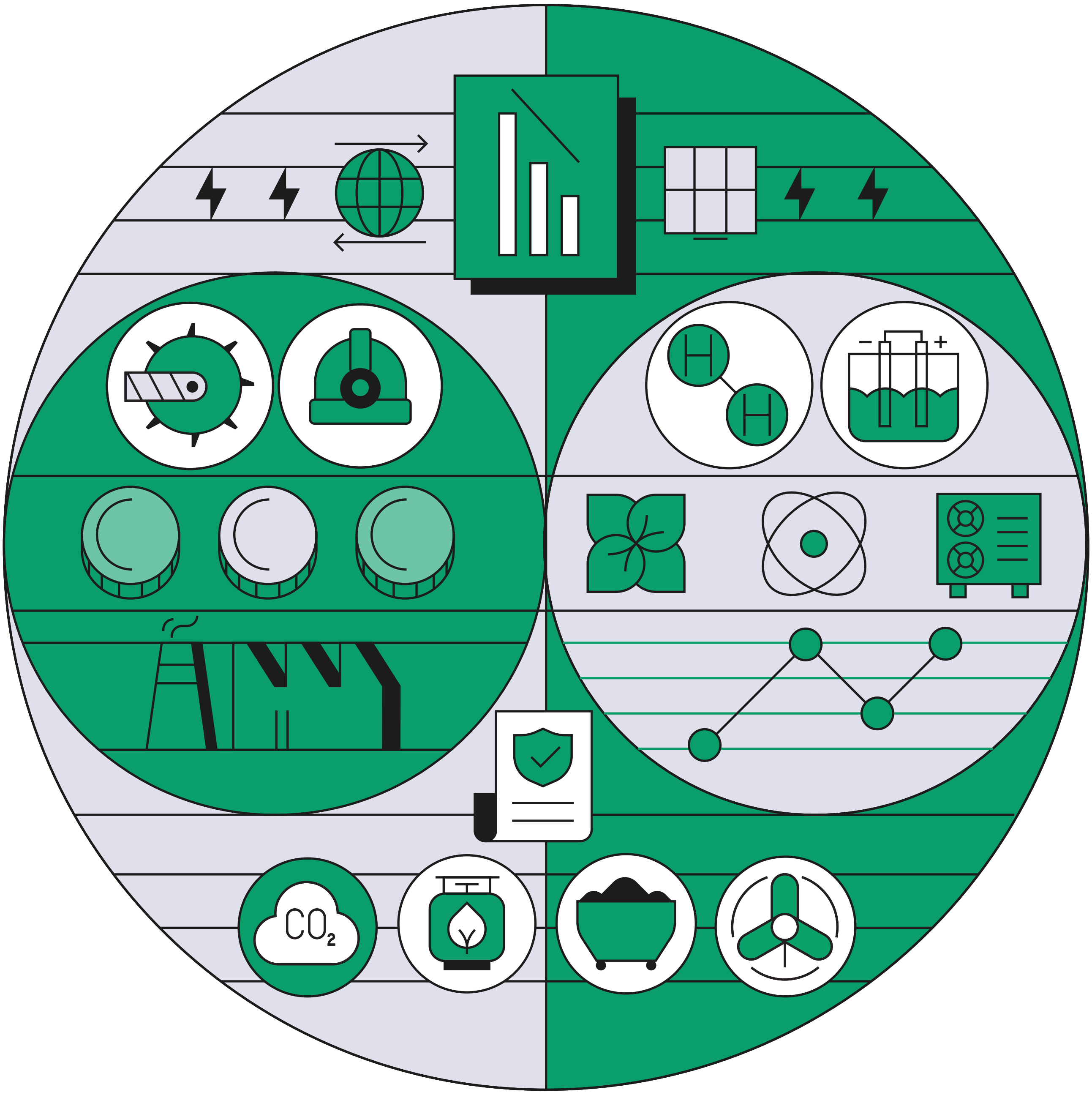
Poland approaching carbon neutrality

Four scenarios for the Polish energy transition until 2040



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Instrat Policy Paper 06/2023

Patryk Kubiczek
Michał Smoleń
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Authors:
Patryk Kubiczek
Michał Smoleń
Wojciech Żelisko

In collaboration with:
Bernard Swoczyna
Jarosław Kopeć
Michał Hetmański

Contact:
Patryk Kubiczek
patryk.kubiczek@instrat.pl

Michał Smoleń
michal.smolen@instrat.pl

Editor (Polish):
Julia Zaleska

Translation:
Wojciech Żelisko
Zofia Borowczyk
Patryk Kubiczek
Michał Smoleń

Cover design and typesetting:
Anna Olczak

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All errors are ours.
Usual caveats apply.

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Instrat Foundation
ul. Hoża 51
00-681 Warsaw
www.instrat.pl

Table of contents

Key findings and numbers

84%

A realistic and economically feasible target for the share of renewable energy in satisfying the domestic electricity demand in 2040 in the ambitious RES and nuclear scenario (S1). Nuclear power (14%) and natural gas (5%) meet the rest of the demand. In the ambitious RES deployment scenario without nuclear power (S2), the RES share reaches 92%.

-68%

CO_2 reduction potential in the analysed sectors (responsible for approx. 75% of domestic emissions) in a 2040 horizon, relative to 2020. Relative to Poland's 1988 Kioto baseline, this is approx. -80%.

6 bln PLN/year

Annual OPEX and CAPEX savings in the electricity, heating, and hydrogen sectors in the ambitious RES and nuclear deployment scenario (S1) compared to the baseline scenario (S3) in 2040. Compared to the slow transition scenario (S4), the difference is 21 bln PLN/year.

1.3 mln t H_2

Economically viable electrolysis-based hydrogen production potential in 2040 under the ambitious RES and nuclear deployment scenario (S1). This value is higher than the current domestic consumption of hydrogen produced from natural gas.

80 GW

Possible peak load in the power system during the windiest and sunniest hours in 2040 under the ambitious RES deployment scenarios (S1, S2).

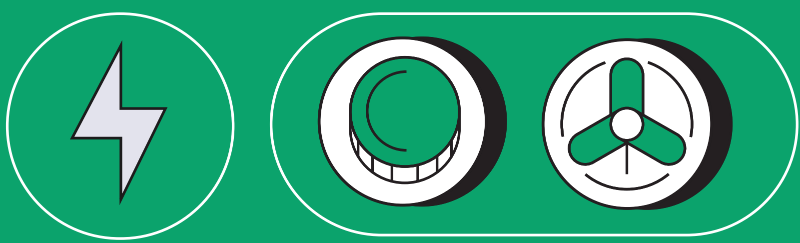
- Using the PyPSA-PL optimisation model of the Polish energy system, we analyse **four energy transition scenarios:**
  - S1 – ambitious RES and nuclear power deployment scenario (RES+NUC),
  - S2 – ambitious RES deployment scenario without nuclear power (RES),
  - S3 – baseline scenario (BASE),
  - S4 – slow transition scenario (SLOW).

- For the purpose of the analyses, **we have expanded the PyPSA-PL model by including new sectors** closely integrated with the electricity sector: district and decentralised heating, light vehicle mobility, and hydrogen production. In addition, we have included energy demand from other sectors and emissions linked to fossil fuel use in other sectors as a set of assumptions for the model. PyPSA-PL identifies the optimal technology mix in terms of investment and operating costs for the entire energy system, assuming a uniform cost of carbon dioxide (CO_2) emissions across all sectors.

- **Availability of clean, renewable energy enables an economy-wide phase-down of fossil fuels.** A power system that produces more electricity, occasionally stabilised by fossil fuels, can be more beneficial in reducing emissions than a smaller system entirely based on zero-emission power plants. This is because the additional electricity output can power heat pumps, electric vehicles or electrolysers, decreasing overall coal, gas, petrol or diesel consumption.

- **Nuclear power can support the Polish energy transition but will not be its pillar.** Investments in RES cannot be held back in the hope of rapid deployment of nuclear power. However, this report shows that these two technologies can work well together.

- **Ensuring energy security in the slow transition scenario (S4) would require more significant investments in natural gas infrastructure** and its increased use. The total yearly cost of providing energy services is higher in this scenario than in others. Therefore, the claim that an ambitious RES-oriented energy transition is an excessive burden on the Polish economy is unjustified.



1. A future marked by clean energy sources and electrification

Poland has irreversibly embarked on the energy transition path, joining global and European efforts to reduce greenhouse gas emissions, primarily linked to burning fossil fuels. The European Union discourages the use of coal and gas in power plants with rising costs of carbon emission allowances. Technological progress is increasing the attractiveness of solar panels, batteries, or heat pumps. High and volatile fossil fuel prices provide another incentive for decarbonisation. In Poland, those are caused by the global energy crisis and the high cost of coal extraction in most Polish mines (WysokieNapiecie.pl, 2023).

Previously, changes in the Polish electricity sector have not always been planned and comprehensive. The blocking of new onshore wind power investments between 2016 and 2023 is the most notorious example of such a mistake. The underestimation of faster RES deployment benefits has also contributed to negligence in developing and modernising electricity grids or adapting conventional power plants to work well with weather-dependent photovoltaic installations and wind turbines. While looking forward to the realisation of long-term national megaprojects (offshore wind power, nuclear power), we have not fully exploited the opportunities to rapidly reduce fossil fuel use by deploying distributed solar and onshore wind power.

Polish transformation strategies have so far insufficiently considered the role of electrification of sectors such as district and decentralised heating, transport, or industry. Heat pumps or other electricity-based technologies are more efficient than conventional solutions. Integrating them into the increasingly low-emission Polish electricity system will increase climate and environmental benefits.

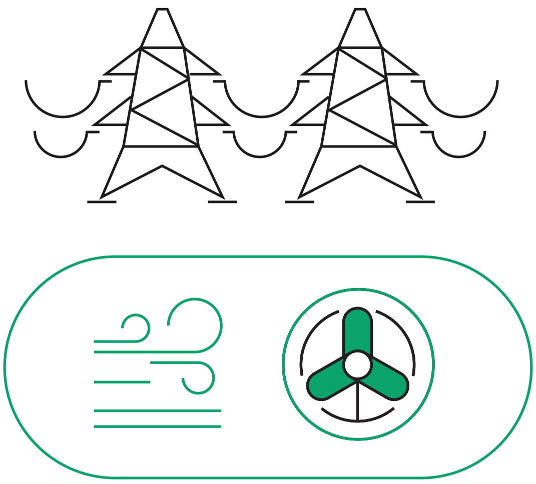
The transformation of the electricity system will have two aspects:

- meeting the current demand for electricity using cleaner energy sources,
- meeting new demand resulting from the spread of electricity-based technologies in various sectors of the economy.

In this report, the Instrat Foundation presents four different scenarios for the development of the Polish energy system until 2040. The aim is to support discussions and assist in developing public policies regarding the future of the Polish energy sector, including a necessary update of *the Energy Policy of Poland until 2040* and *the National Energy and Climate Plan for 2021-2030*.

Our study also includes estimates of the achievable GHG emission reduction target, which can provide a Polish contribution to discussions at EU and international forums on setting such a target for 2040.

We believe that the results of this study will contribute to defining an ambitious climate target for the Polish government and setting a roadmap for the Polish economy – for businesses, local authorities and financial institutions, as well as for citizens involved from the outset.



2. Modelling assumptions

This report presents the results of scenario-based analyses conducted using the PyPSA-PL tool, developed internally by the Instrat team in consultation with the international PyPSA (Python for Power System Analysis) expert community. The main reference point for our analysis is research performed using the PyPSA-Eur optimisation model of the European energy system, which explores the benefits of sectoral integration and the development of a pan-European electricity grid (Neumann et al., 2023).

2.1. Analysis using the PyPSA-PL model

PyPSA-PL is a tool that identifies and simulates cost-optimal development pathways for the Polish energy system. Modelling is based on a range of data and assumptions, including the current structure of the Polish energy sector, future prices of fossil fuels, greenhouse gas emission allowances, the cost of investment in new power plants, and the demand for various energy carriers at any given hour of the year. We have also considered certain technical constraints, such as the achievable pace of constructing new power plants or ensuring appropriate operating parameters of the electricity system.

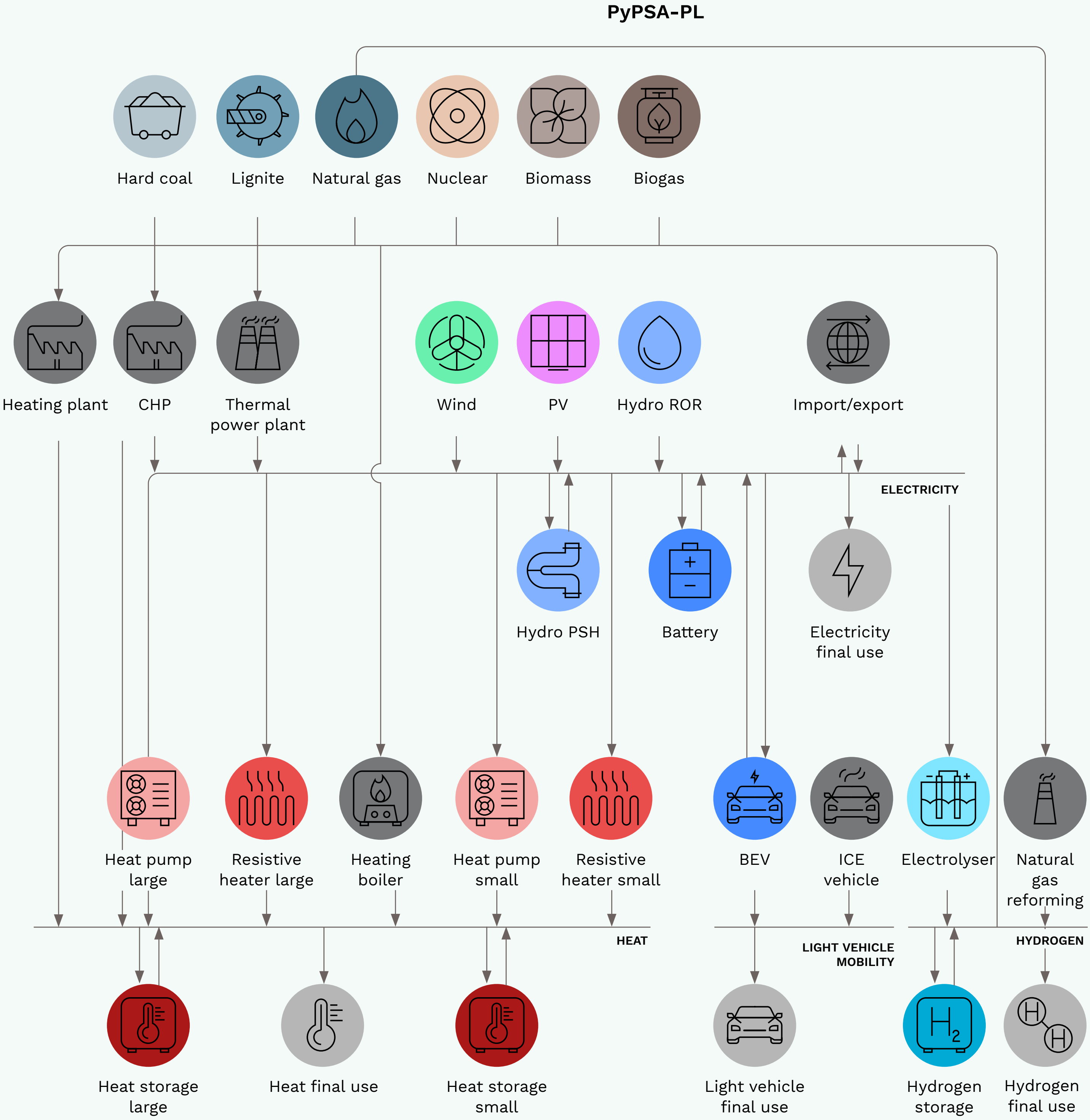
The current model analyses not only the supply of electricity to consumers but also centralised and decentralised heat (integration of district heating and individual heating in buildings), energy for powering light road vehicles, and hydrogen (used in industry).

The utilisation profiles of heat pumps, electric car chargers, or electrolysers for hydrogen production are subject to optimisation. This way, we reflect both the growth in demand for electricity and pending changes in its use characteristics (e.g., charging electric cars during periods of lower electricity prices). Although our model does not consider the entire economy, it directly simulates the functioning of sectors currently responsible for around 60% of greenhouse gas emissions in Poland[1].

Further, we present an illustrative diagram of the latest version of the PyPSA-PL model (Diagram 1). More detailed information on the model's selected assumptions and operation principles can be found in Appendices A and B. The entire model with the complete set of assumptions is also being successively published on the GitHub platform under an open licence, free of charge, allowing its development and replication by the expert community (Kubiczek, 2023b). The full results of the analyses conducted for this report are available on the Zenodo platform (Kubiczek, 2023c).

1 Together with emissions from other energy uses of fossil fuels that we represent indirectly in the model, this is about 75%.

DIAGRAM 1. Technologies, energy carriers, and energy flows in the sectorally integrated version of the PyPSA-PL model



Source: Instrat's own analysis. The diagram is simplified; not all fuel and technology combinations are allowed.

2.2. What are our results?

What will be the cheapest way to supply electricity and heat to Polish consumers in the future? The PyPSA-PL model allows us to answer this question based on a specific set of assumptions regarding prices and technical characteristics of the energy system components. We optimise both investment (such as constructing a new power plant) and operating costs (such as fuel purchase).

The price of CO_2 emission allowances plays a special role in the model. It is this key instrument of the European Union's climate policy that provides an economic incentive to reduce emissions – it is better to build wind turbines than to pay for the increasingly expensive allowances needed to burn coal.

Our model does not directly adopt a predefined reduction target (e.g. a 90% drop in emissions by 2040). Instead, the CO_2 emission cost assumption sets the pace of decarbonisation. The model assumes CO_2 prices corresponding to the Announced Pledges scenario from the International *Energy Agency's World Energy Outlook 2022* (IEA, 2022) for countries committed to reducing their emissions to net zero. This implies a price of around 140 euro/tonne CO_2 in 2030 and 180 euro/tonne CO_2 in 2040. Our results indicate that emission pricing creates an economic incentive for a rapid transformation of the analysed sectors.

In this report, we present four scenarios for the development of the Polish energy system. Each is based on a different set of assumptions about the possible pace of change in the system. For example, the scenario of ambitious RES and nuclear power deployment (S1) assumes that a rapid capacity growth of these technologies is technically possible. Then, the model verifies how cost-efficient it actually is. On the other hand, the slow transition scenario (S4) also involves optimising investments and operations but within the limits set by assumptions of insufficient readiness of the power grid infrastructure or regulatory environment.

Every modelling exercise – including ours – is based on certain assumptions and simplifications that must be considered when interpreting the results. The PyPSA-PL model does not take into account the cost of investments in electricity grids. Instead, we assume that the effectiveness of state institutions, network operators (DSOs, TSO), and other economic actors in Poland regarding grid development are among the key factors differentiating the various energy transition scenarios. Analogously to other models, we consider some technical limitations of the Polish power system's operations only in an approximate way.

A similar limitation applies to district heating, which we treat in an aggregate manner, whereas in reality, it consists of many distinct and isolated systems. Our model also does not analyse issues such as the security of supply of particular fossil fuels or critical raw materials. However, it should be acknowledged that the necessity of rapid deployment of RES and electrification of the economy, as suggested by the cost-based analyses, will reduce dependence on natural gas imports in the next decades.

We do not simulate in detail the operation of the power exchange or the CO_2 allowances market (e.g. strategic actions of large energy enterprises) – we look for the optimal solution from the perspective of the entire system. We recognise that energy markets have limitations, sometimes leading to suboptimal new capacity investments. However, this is an area for state intervention. Similarly, as a general rule, we do not simulate the current shape of regulation and state interventions other than emission pricing (e.g. contracts for difference for hydrogen production)[2]. Instead, we assume that the regulatory environment will evolve to enable positive changes in the Polish and European energy sectors (especially in the ambitious scenarios). The details of our model's limitations are described in Appendix B.

2.3. What is new compared to previous studies?

The Instrat Foundation presented its first scenario for an ambitious energy transition in a series of 2021 publications: *Achieving the goal* (Czyżak and Wrona, 2021), *What's next after coal?* (Czyżak, Sikorski et al., 2021) and *The missing element* (Czyżak, Wrona et al., 2021). The optimal pathway to exploit the potential of renewables inspired expert discussions and contributed to the increase in projected RES capacity in the proposal of the new PEP2040 scenario.

These studies were the starting point for a new edition of the research project launched in 2022. As part of it, in March 2023, we published the report *Poland cannot afford medium ambitions. Savings driven by fast deployment of renewables by 2030* (Kubiczek and Smoleń, 2023), in which we presented the benefits of a more dynamic power system transformation up to 2030. Furthermore, in August 2023, we presented the study *Baseload power. Modelling the costs of low flexibility of the Polish power system* (Kubiczek, 2023a) containing an analysis of the causes and consequences of constraints on integrating high wind and solar output levels in the Polish power system.

This report goes a step further, covering the analysis up to 2040. It also more broadly considers the electrification of district heating, light vehicle mobility, and hydrogen production. Moreover, it incorporates the technical limitations of the power system penetration by non-synchronous sources[3]. For the first time, our model optimises not only the supply of energy but also its use (in addition to the charging of electricity storage units, already taken into account in the previous reports).

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2 We do, however, allow for some exceptions to this rule – we assume that certain technologies may develop faster than optimally due to public support. This applies, for example, to investments in biogas production plants or electrolysers for hydrogen production.

3 In line with the methodology described in the report *Baseload power*, we assume that at any point in time the power system penetration by non-synchronous sources, i.e. solar and wind power, batteries, as well as DC interconnectors, cannot exceed a preset value.

3. How did we develop our scenarios?

This report presents four pathways for the Polish energy transition up to 2040. We have analysed two ambitious scenarios differing by the presence (S1) or lack (S2) of nuclear power in the electricity mix, a baseline scenario (S3) in which RES deployment matches the ambitions presented by the Ministry of Climate and Environment in June 2023 (MKiŚ, 2023), and a pessimistic, slow transformation scenario (S4) in which positive changes occur much slower.

SELECTED ASSUMPTIONS DIFFERENTIATING THE SCENARIOS

The price assumptions are the same for all scenarios. The scenarios differ in their assumptions regarding specificities, such as the possible rate of new capacity additions and annual demand for different energy carriers. More specifically, assumptions that differentiate the scenarios are:

- The maximum level of installed wind and solar capacity in a given year, or the maximum rate of new capacity additions – the more ambitious the scenario, the higher the level of RES capacity can be.

- The maximum rate of new capacity additions for other technologies – including nuclear and gas-fired power plants.

- Final use electricity demand originating from the outside of the modelled sectors – we implicitly assume that the availability of cheap renewable energy leads to faster electrification in industry, heavy transport, and households, increasing baseline electricity demand (i.e., excluding demand from power-to-heat technologies or electric cars).

- Space heating demand – we assume that in more ambitious scenarios, insulation retrofits in buildings (and replacing old inefficient building stock) occur more rapidly, reducing the demand for space heating.

- Car transport – in more ambitious scenarios, the pace of growth of the electric car fleet is higher, and the demand for individual car transport decreases due to support for alternative mobility options (public transport, cycling, etc.).

- Hydrogen demand – it is slightly higher in the ambitious scenarios as those are associated with higher expectations for low-carbon hydrogen use in the transport sector and industry.

- Maximum instantaneous power system penetration by non-synchronous sources (i.e. wind and solar, as well as batteries) – in more ambitious scenarios, power grid investments and the development of ancillary services allow for better integration of RES (Kubiczek, 2023a).

Details of these assumptions can be found in Appendix A.

SCENARIOS ANALYSED

We have considered the following scenarios in the analysis:

- **S1 – ambitious RES and nuclear power deployment scenario (RES+NUC)** – this scenario assumes the Polish state recognises the energy transition as a key challenge of our time. A several-fold increase in investments and the mobilisation of state institutions, infrastructure operators, and the private sector contribute to modernising and expanding the electricity grid. Spatial planning regulations are friendly to RES deployment, and authorities have sufficient resources to ensure that the relevant administrative processes proceed without unnecessary delays. The nuclear programme is being implemented at a spectacularly fast pace for Europe (with a delay of only about two years compared to current declarations). We are no longer building new gas-fired power plants after 2030, even if the alternatives are initially more expensive. Thanks to widespread support programmes, buildings in Poland are undergoing thorough insulation retrofits, which reduce space heating demand. Polish citizens are gradually shifting to electric cars and public transport.

- **S2 – ambitious RES deployment scenario without nuclear power (RES)** – this scenario is identical to the previous one (S1); however, the nuclear programme is abandoned or significantly postponed so that no nuclear reactor is operational until at least 2040.

- **S3 – baseline scenario (BASE)** – in this scenario, the state creates good conditions for the energy transition, but to a lesser extent than in the ambitious scenarios. For this reason, the maximum rate of RES deployment corresponds to the targets presented in the governmental document *Scenario no. 3 for the pre-consultation of the NCEP/PEP2040 update* (MKiŚ, 2023) published in June 2023. It should be emphasised that achieving even such targets requires several significant measures, e.g. a thorough modernisation of the electricity grid. Nuclear power can be deployed as fast as in the S1 scenario (very high pace).

- **S4 – slow transition scenario (SLOW)** – in this scenario, the low effectiveness of the state intervention leads to a low pace of the energy transition. A lack of grid connection approvals or long and costly administrative processes halt investments in onshore wind and solar PV. The nuclear programme is running five years behind schedule. The problem of delays also applies to offshore wind power or even new gas capacity. Heat demand remains high due to the slow pace of insulation retrofits in buildings.

It should be stressed that the assumptions for the scenarios do not directly address installed capacities, e.g., installed solar or wind power. They only set maximum levels that can be reached if it is cost-effective from a system-wide point of view.

4. Four scenarios for the Polish energy transition

This chapter will present modelling results of the four scenarios for the Polish energy transition. These have been developed according to the assumptions presented above.

For context, we provided average historical data for the 2019-2021 reference period[4] or, in the case of the electricity sector, for 2022. We assume that the first significant deviations in the energy system trajectory between scenarios occur in 2030 due to differences in investments completed in 2026 and beyond.

We optimised the energy system cost sequentially for 2030, 2035 and 2040. For each of those years and each scenario, we present the following model outputs:

- **Key electricity sector data:**
  - **Installed electrical capacity** – installed capacity of power plants of various kinds, as well as of storage units, interconnectors (enabling cross-border electricity trade), and DSR (demand side response, i.e. remunerated reduction of electricity consumption by end users at the request of the transmission system operator).
  - **Electricity production and trade** – the structure of the annual production, broken down by various kinds of power plants, also considering net exports or imports and the use of DSR.
  - **Structure of domestic electricity demand** – electricity use, distinguishing between electricity demand from centralised and decentralised power-to-heat technologies, electric cars, and electrolysers, as well as from final use in households, industry, and other electrified sectors.
- **Key heating sector data:**
  - **Installed capacity in district heating** – installed thermal capacity of various centralised combined heat and power generators, heat-only boilers, power-to-heat technologies, and heat storage units.
  - **Heat production in district heating** – the structure of annual centralised heat production, considering the different types of heat generation technologies with (or without) cogeneration.

4 Later in the report referred to simply as 2020.

  - **Installed capacity in decentralised heating** – installed thermal capacity in individual heating installations (conventional boilers, heat pumps, peak resistive heaters) and distributed heat storage.

  - **Heat production in decentralised heating** – the structure of annual decentralised heat production, considering different technologies.

- **Selected profiles of electricity generation and use in 2040 over three-day periods:**

  - **in May** – characterised by good windiness on two of the three days, sunny days, low, but non-zero, heat demand (a relatively favourable period for a RES-based energy system),

  - **in February** – low wind and little sunshine, high heat demand (unfavourable period for a RES-based energy system).

In the remainder of this chapter, we present comparative data on system-wide costs and emissions for each scenario. In-depth results for each sector are presented in the next chapter.

4.1. Scenario 1: ambitious deployment of RES and nuclear power

In scenario 1 (RES+NUC scenario), the model has the most freedom to find the most effective path for the Polish energy system. Our assumptions enable a rapid deployment of RES and nuclear power. Almost full exploitation of this potential turns out to be optimal.

ELECTRICITY – FIGURE 1

In 2040, Polish wind and solar power plants account for 73% of annual electricity production.

- In the 2020s, Poland is further filling the gap caused by past negligence, mainly regarding wind power. Clean and cheap electricity from RES displaces fossil fuels from the electricity mix, as those are burdened by the high CO_2 emission fees.

- In the 2030s, wind and solar play a vital role in the electrification of other sectors, contributing to a decline in coal and natural gas use in residential boilers, petrol or diesel in transport, and methane in industrial hydrogen production.

- In 2040, Poland already has 59 GW in solar power and 52 GW in wind power (including more than 17 GW in the Baltic Sea). To this end, it will be necessary to drastically increase the rate of investment in the modernisation of electricity grids, as well as the adaptation of the system – both on a technical side, by permitting RES installations and battery storage facilities to provide ancillary services, and on the market side, by creating appropriate incentives for the use of energy mainly during high RES generation hours.

With almost 6 GW of nuclear power capacity, Poland can reduce the baseload operation of carbon-intensive power plants. In the ambitious scenarios (S1 and S2), we assume that by 2040, the Polish power system will be mostly independent of the forced baseload operation of dispatchable turbine-equipped power plants, although not fully (we assume that they must account for 5% of instantaneous generation, vs ca. 35-40% of the generation today). Nuclear power plants can replace CO_2-emitting coal or gas-fired plants in this role, especially given the high cost of biogas or hydrogen. Nuclear power also provides support at times of low RES generation, although due to limited capacity, it can only meet a fraction of the hourly demand. However, it is essential to bear in mind that the construction of nuclear power plants may take longer than assumed or never be completed, leading to billions of PLN in extra costs.

We still need many dispatchable fossil fuel power plants in 2040, but they only account for less than 5% of annual production. With the deployment of clean energy sources, overall production from fossil fuels is declining rapidly. Coal and gas power plants will increasingly only serve to stabilise the majority of production from wind and solar (before being replaced in this role by low-carbon ancillary services or nuclear power plants). On the other hand, Poland will still experience long periods of unfavourable weather for RES in 2040, requiring coal or gas units to come online with full load. Decommissioning conventional power plants fully will be thus much more difficult than minimising their use. Maintaining rarely used units will require appropriate market instruments, such as continuing the capacity market. Ultimately, power plants powered by hydrogen (or other synthetic fuels), biogas or biomethane may take over the role of dispatchable peaking capacity. However, the high production costs of these fuels and their limited scalability are significant barriers.

Demand for electricity from coal declines rapidly – from the current approx. 115 TWh to as little as approx. 8% of this figure as early as 2030. Because of the higher emissions per electricity unit, lignite power plants are hit the hardest by the carbon allowance costs, resulting in their dispatch only in the coldest moments of the year. Hard coal will be affected too, as demand for this fuel in power generation would decline from approx. 40 million tonnes per year to approx. 5 million tonnes per year – the equivalent of the production of two or three medium-sized mines.

Our price scenario indicates that coal – the current foundation of the Polish energy system – will lose market share not only to clean energy sources but also to new gas-fired power plants with lower ETS costs. The model suggests that the remnants of coal-fired power generation (the most efficient units operating at supercritical parameters) may survive until 2040 in an economically justifiable manner, mainly due to the assumption of the ban on financing the construction of new gas-fired units after 2030.

The availability of clean energy enables the electrification of sectors. This applies primarily to decentralised heating, to a limited extent to centralised (district) heating, and later to hydrogen production, because of which annual electricity consumption rises to almost 310 TWh in 2040 (against 160 TWh in 2022). The rapid deployment of wind and solar power increases the profitability of investments in power-to-heat technologies, i.e. heat pumps and resistive heaters. In 2030, the utilisation factor of 2 GW of electrolysers (in line with the target of the Polish Hydrogen Strategy) is minimal but increases significantly in the next decade (see section 5.4 for results for hydrogen). The importance of electrification for the future of the electricity sector is not only due to additional demand but also to its partial flexibility (e.g., the possibility of powering electrolysers at times of high RES generation). Transforming the Polish power sector would be much more complex and costly without higher demand flexibility.

HEATING – FIGURE 2

The profound transformation of the electricity sector is accompanied by a major shift of heat production methods. However, district heating and decentralised heating follow different paths.

In district heating, the leading trend is to move towards efficient combined heat and power generation – initially also gas-fired, and after 2030, increasingly based on environmentally sustainable agricultural biomass and biogas. If the potential for bioenergy cannot be realised due to limited fuel availability, this will translate into a higher use of fossil fuels. Large-scale heat storage plays a vital role as one of the key energy storage technologies for the country's entire energy system.

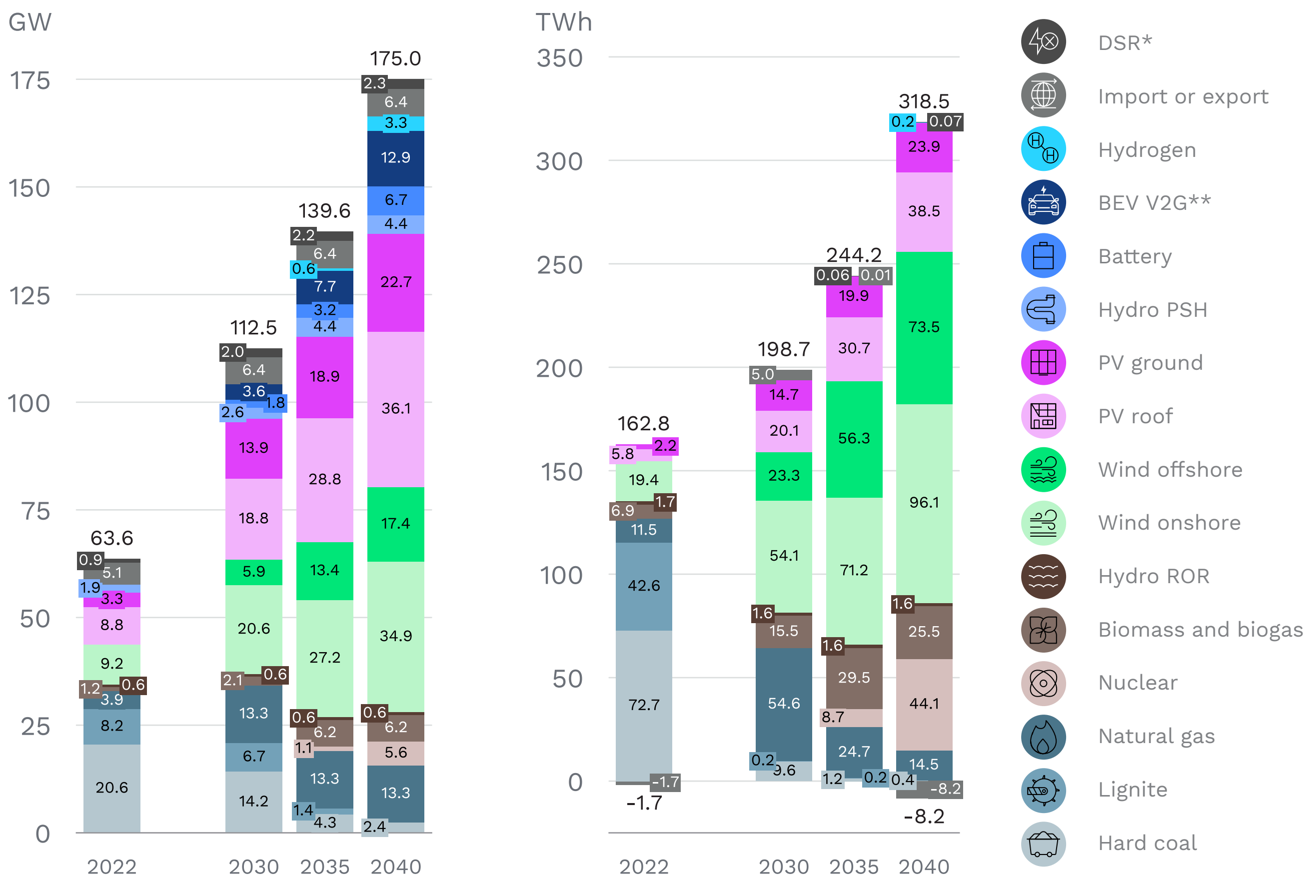
In the decentralised heating of individual buildings, the future lies primarily in electrification – mainly heat pumps (2/3 of heat production in 2040) equipped with supporting peak resistive heaters. In the ambitious scenario, we are phasing out coal combustion in households as early as 2030 (to improve air quality, but also for economic reasons), while gas by 2040.

The coupling between the power and district heating sectors promotes the electrification of decentralised heating in buildings. CHP plants in district heating support the power system on windless winter nights and also contribute to stabilising the system's operating parameters throughout the year. The use of heat pumps in buildings, on the other hand, enables shifting away from the least efficient use of coal and gas – burning them in residential boilers.

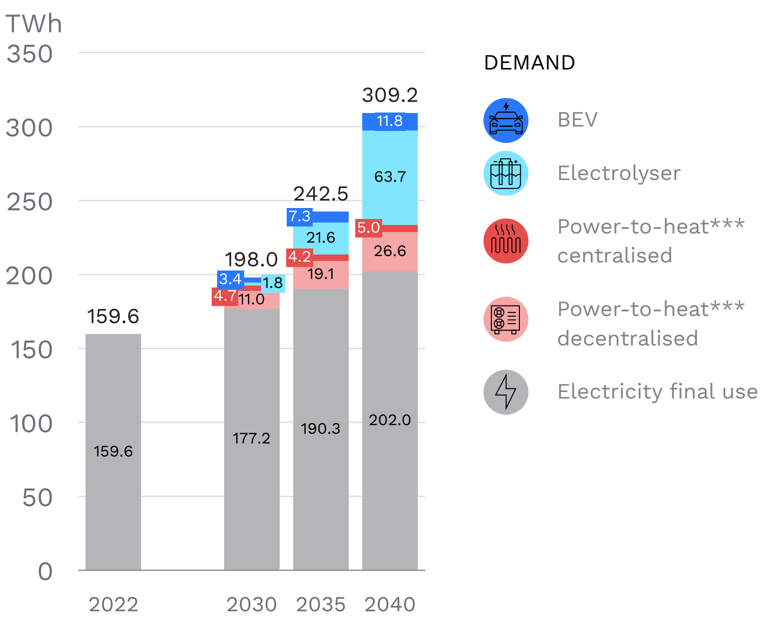
FIGURE 1. Electricity sector in the ambitious RES and nuclear power deployment scenario (S1)

A. INSTALLED ELECTRICAL CAPACITY (GW)

B. ELECTRICITY PRODUCTION AND EXCHANGE (TWh)



C. STRUCTURE OF DOMESTIC ELECTRICITY DEMAND (TWh)



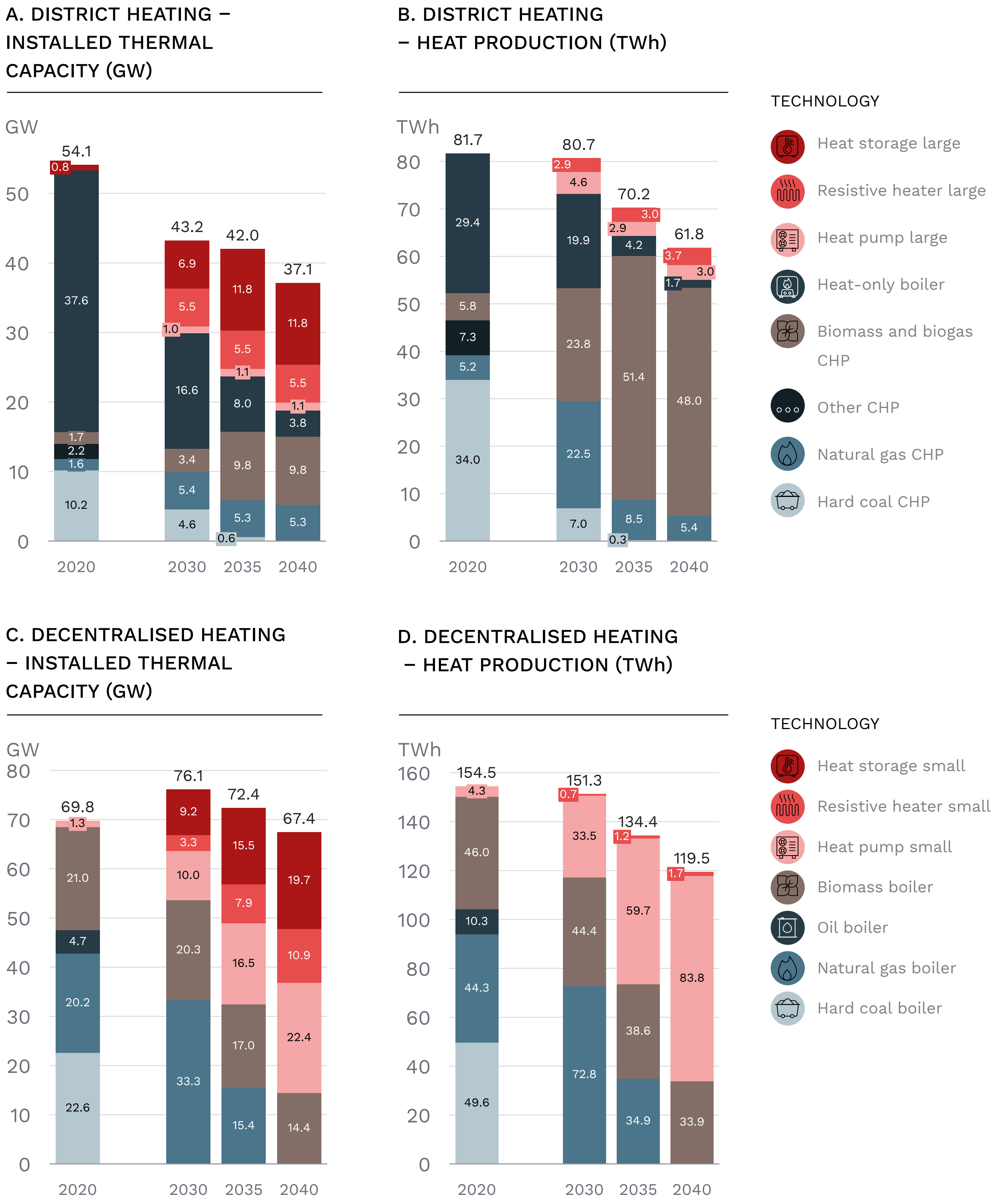
Source: Instrat's own analysis. 2022 – historical data based on ARE. 2030-2040 – results of the PyPSA-PL optimisation model. Net capacity and production are shown, i.e. excluding the own demand of the conventional generating units. Electricity demand includes transmission and distribution losses.

* DSR – Demand Side Response; remunerated reduction of electricity consumption by end users at the request of the transmission system operator.

** V2G – vehicle-to-grid; supplying power to the grid from electric vehicle (BEV) batteries.

*** Centralised power-to-heat technologies are large heat pumps and resistive heaters in district heating networks; individual power-to-heat technologies are small heat pumps and peak resistive heaters in buildings.

FIGURE 2. Heating sector in the ambitious RES and nuclear power deployment scenario (S1)



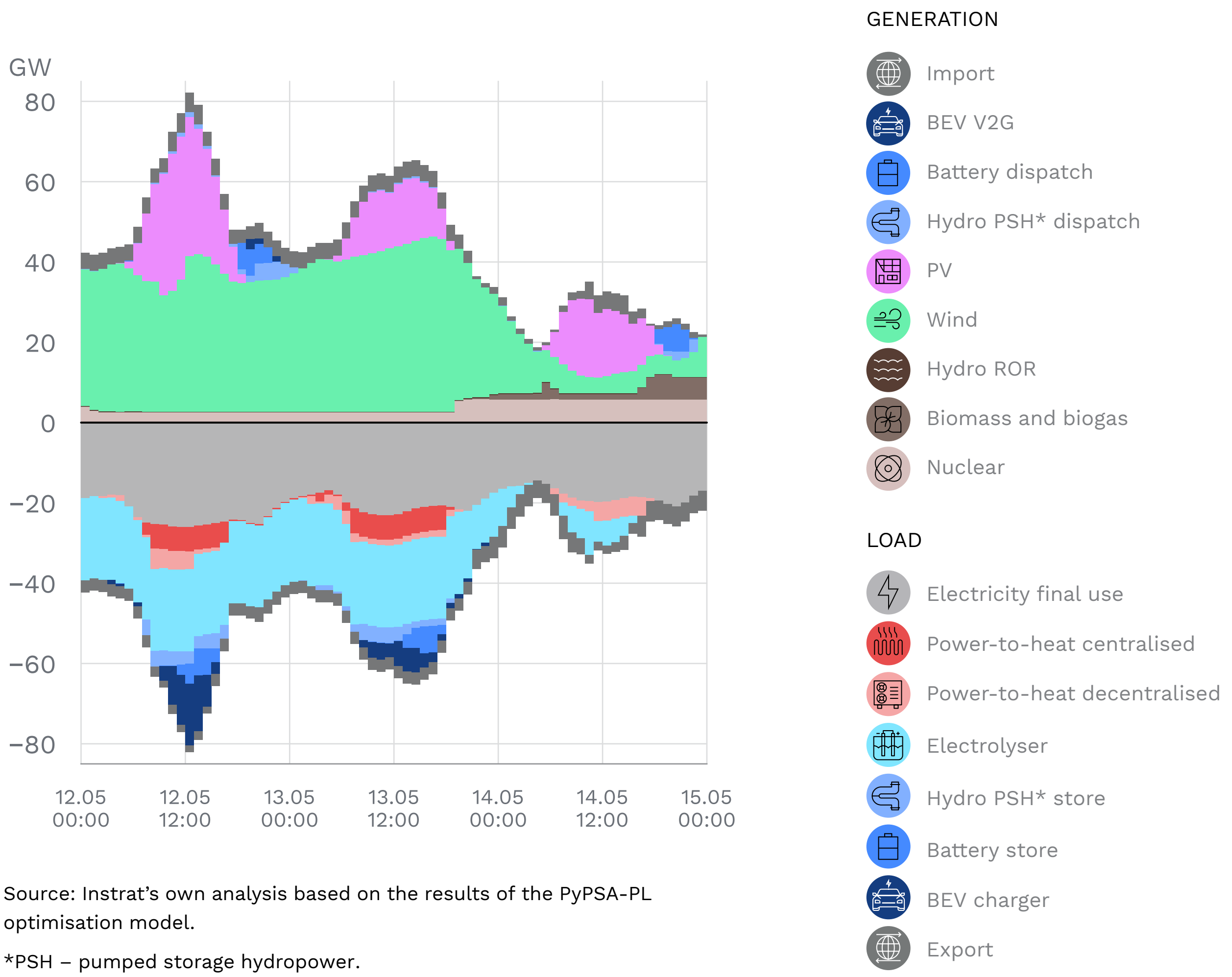
Source: Instrat's own analysis. 2020 – average of 2019-2021 historical data. Historical data for district heating based on ARE, URE, Forum Energii, and own assumptions; for decentralised heating based on GUS, Eurostat, and own assumptions. The historical installed capacity in decentralised heating is an estimate. 2030-2040 – results of the PyPSA-PL optimisation model. We assume that from 2030 onwards, heat-only boilers burn only natural gas. For decentralised heating, we assume that a small heat pump operates jointly with a peak resistive heater and heat storage (without fuel-fired boilers being separate systems). The shown thermal capacity of heat pumps should be interpreted as a temperature-independent peak heat output.

SELECTED PERIODS OF POWER SYSTEM OPERATION

LATE SPRING – FIGURE 3

On the first two days of the selected period in May, our energy system experiences an abundance of clean energy – high generation from wind enables powering hydrogen production in electrolysers. Sunny hours are an excellent time to charge electric cars, batteries, pumped storage hydropower plants, and to use large heat pumps or resistive heaters to store heat in district heating systems. Electricity and heat storage units can then satisfy a part of the demand after sunset. On the third day, generation from wind drops significantly. Nuclear power plants reach their full available output level, and electrolysers and residential heat pumps are used only during sunlight hours. After dark, biomass and biogas power plants start up, providing the system with the necessary flexibility.

FIGURE 3. Sample profile of electricity production and consumption in late spring 2040 (GW) in the ambitious RES and nuclear power deployment scenario (S1)



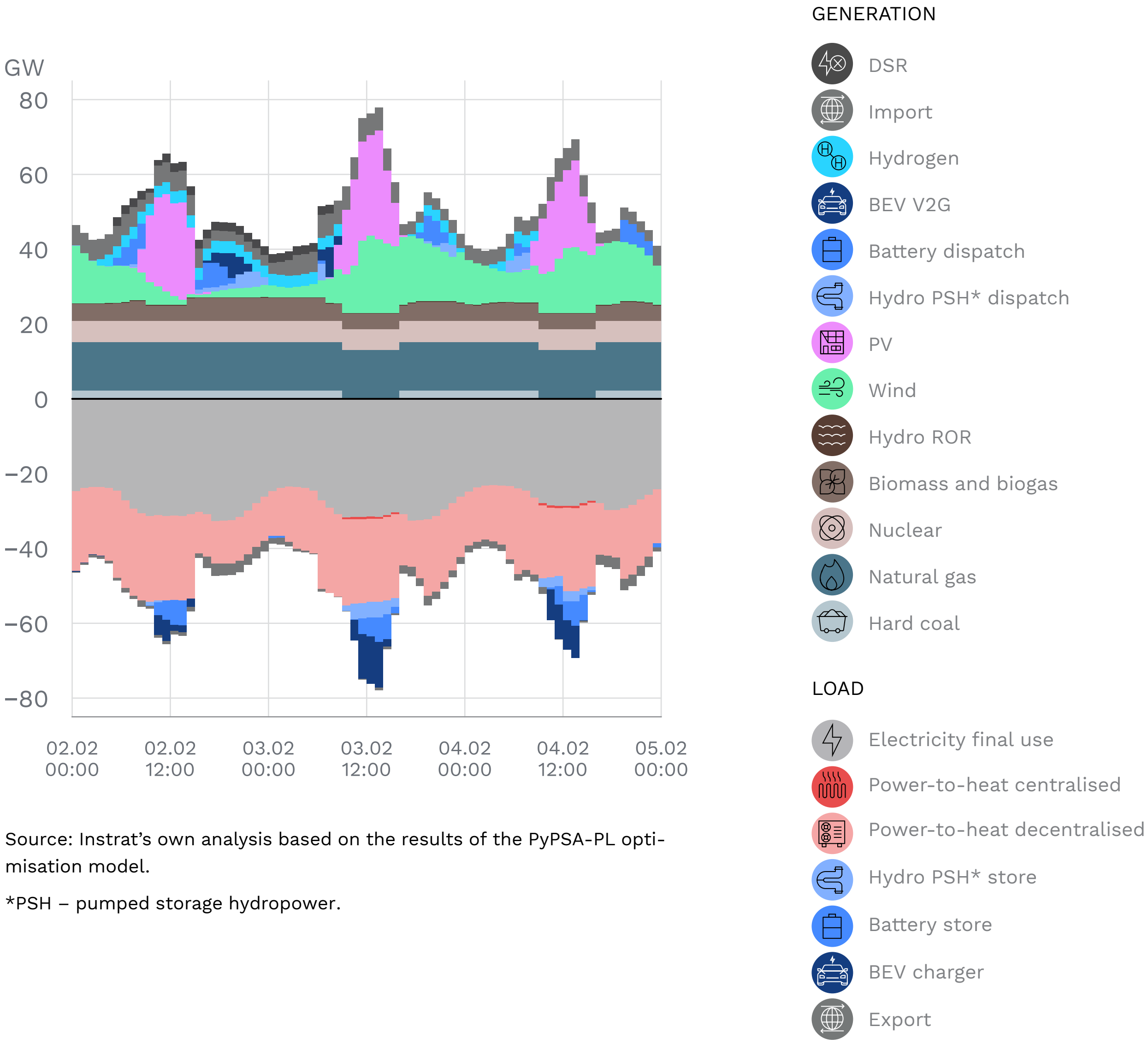
Source: Instrat's own analysis based on the results of the PyPSA-PL optimisation model.

*PSH – pumped storage hydropower.

WINTER – FIGURE 4

This selected adverse weather period in February (low wind, low temperature) poses a challenge to our energy system. Solar power plants operate only for a few hours daily, and wind generation remains low. The demand for electricity increases dramatically due to the need to power many heat pumps operating at low temperatures. As nuclear power plants only meet a small proportion of demand, CHP plants, gas and hydrogen plants, biomass and biogas units, and even the last coal-fired units must be put into operation. An analysis of this period shows why maintaining dispatchable capacities is necessary, especially in view of the electrification of heat production in buildings. The role of widespread insulation retrofits should also be emphasised, without which the electrification of heating would translate into even higher demand peaks in the Polish power system.

FIGURE 4. Sample profile of electricity production and consumption in winter 2040 (GW) in the ambitious RES and nuclear power deployment scenario (S1)



Source: Instrat's own analysis based on the results of the PyPSA-PL optimisation model.

*PSH – pumped storage hydropower.

4.2. Scenario 2: ambitious RES deployment without nuclear power

The Polish economy can also drastically reduce emissions without nuclear power. The process of majority decarbonisation of the Polish power sector should, in any case, take place before the possible first unit is connected to the grid. Therefore, scenarios S1 (RES+NUC) and S2 (RES) are almost identical until 2035, with significant differences emerging only in 2040.

ELECTRICITY – FIGURE 5

In the S2 scenario, we reach 59 GW in solar power and 56 GW in wind power in 2040. Together, these technologies account for 82% of total electricity production. The abandonment of nuclear power deployment leads to a slightly higher level of optimal investment in offshore wind power (21 GW in 2040), offering a more stable production profile at higher investment costs than onshore wind power. Achieving such a high level of weather-dependent RES capacities requires massive investments in the electricity grid – this transition pathway will not succeed without the high institutional capability of the state.

Biomass and biogas account for 6 GW of dispatchable capacity operating at the base of the electricity system in 2040. They are also characterised by a certain degree of flexibility. According to our assumptions, in 2040, our system needs at least 5% of such power sources in each hour of the year. The detailed modelling of bioenergy development is particularly complex due to trade-offs with the agricultural and forestry sectors. Limited biomass availability, especially in the face of increasing biodiversity conservation standards, may hinder its development. If bioenergy does not develop to the level indicated, this will translate into higher use of fossil fuels.

Gas-fired power plants function as peak capacity in the system. Although their capacity is more than twice as high as low-carbon biomass and biogas units, their annual production is about 20% lower due to emission costs. Coal-fired power plants are needed but only occasionally used (transitioning to using coal power plants solely as backup sources happens as early as 2035). Due to required investment costs, it may be more cost-effective to maintain 4 GW of coal capacity until 2040 than to replace it with additional hydrogen power plant capacity, which anyhow reaches about 6 GW. Overall, however, fossil fuel use is higher than the S1 (RES+NUC) scenario; the capacity of fossil fuel-powered units in 2040 is higher compared to the S3 (BASE) baseline scenario with much lower RES ambitions.

The rapid RES deployment speeds up the electrification of sectors. As in the previous scenario, electrification of heating is most important until 2030, and after that, the uptake of electrolysers consuming surplus production from renewables increases (53 TWh in 2040). However, the gap caused by the lack of nuclear power plants is noticeable, especially in the utilisation factor of electrolysers (down by around 15% – cf. section 5.4) and electrified heat in district heating (down by 30%), which is also due to the increased role of conventional, biomass, and biogas CHP plants.

HEATING – FIGURE 6

The transformation of district heating proceeds in the S2 scenario similarly to S1, with the abandonment of the nuclear programme translating into slightly higher (by about 2 TWh) heat production in gas-fired CHP plants; the role of electrification is declining even further.

Heating supply in buildings is again dominated by small heat pumps working together with peak resistive heaters and heat storage. Due to the challenges of meeting peak demands in winter, electrification of district heating is occurring somewhat more slowly. Still, the differences in heat pump capacity and generation are only a few per cent, which is due to the generally high effectiveness of these technologies in reducing fossil fuel consumption. The difference between the RES+NUC and RES scenarios is more apparent in the production of hydrogen, a process with much lower cost-efficiency.

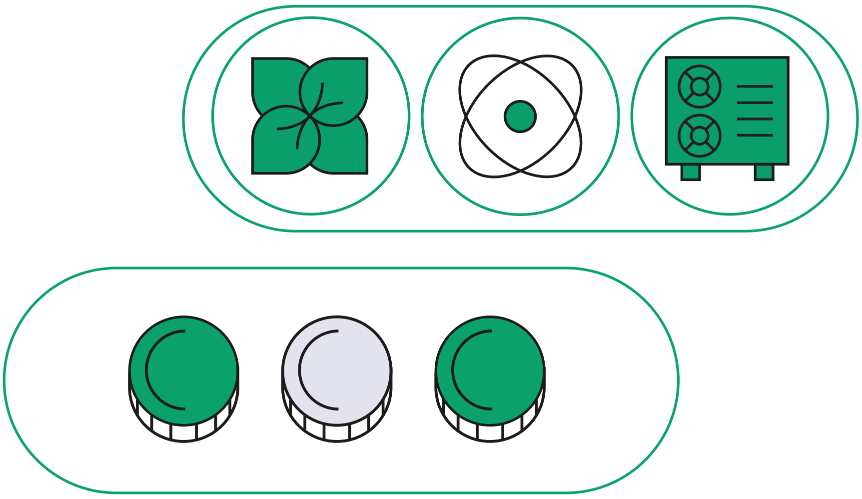
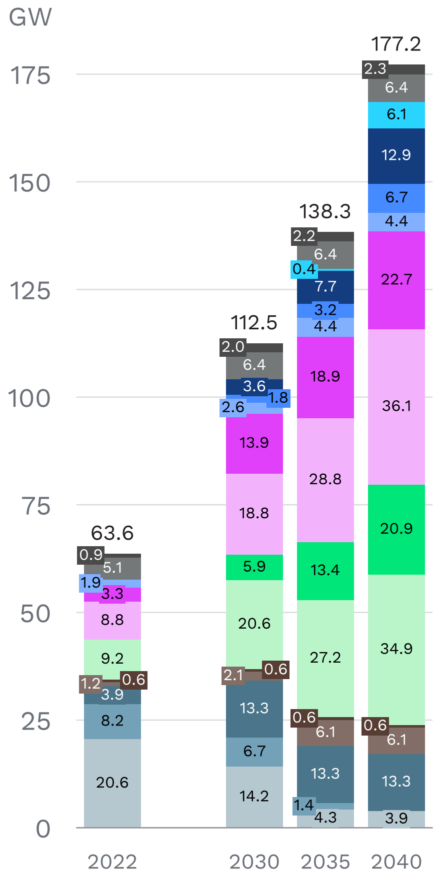
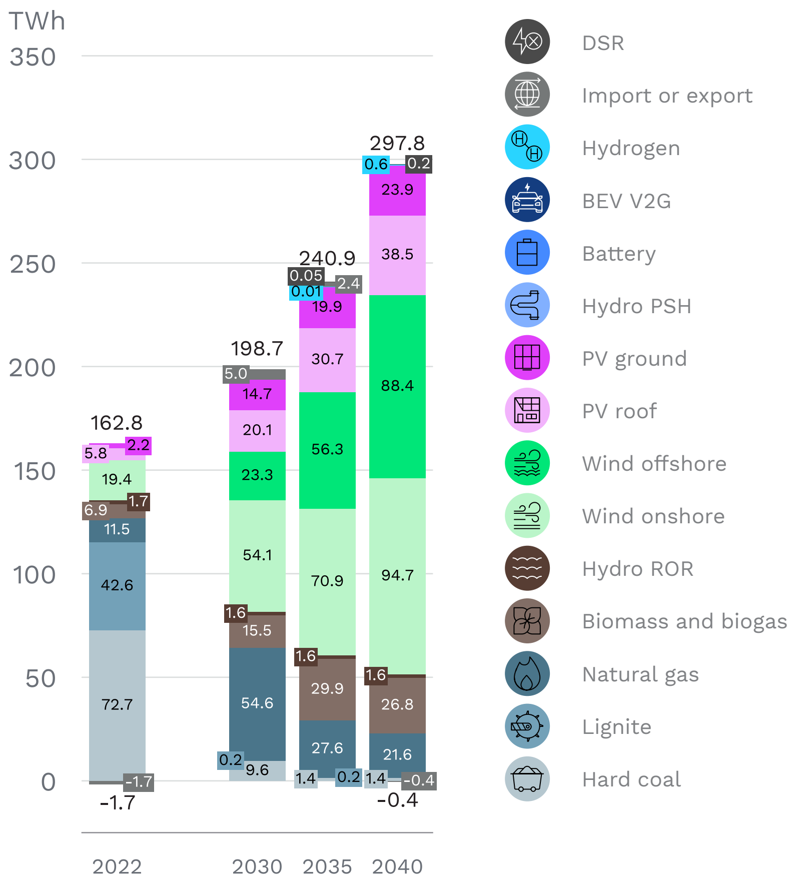


FIGURE 5. Electricity sector in the ambitious RES deployment scenario without nuclear power (S2)

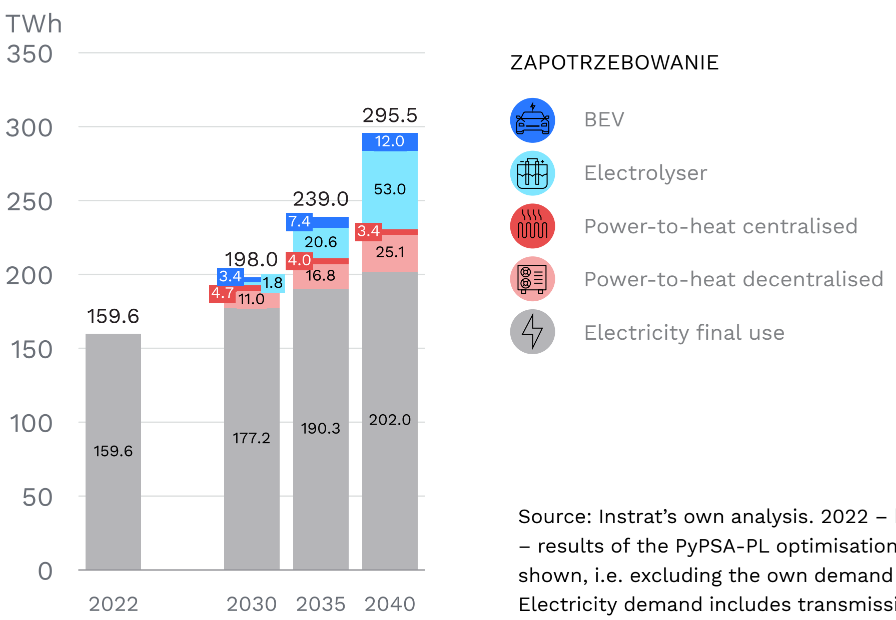
A. INSTALLED ELECTRICAL CAPACITY (GW)



B. ELECTRICITY PRODUCTION AND EXCHANGE (TWh)

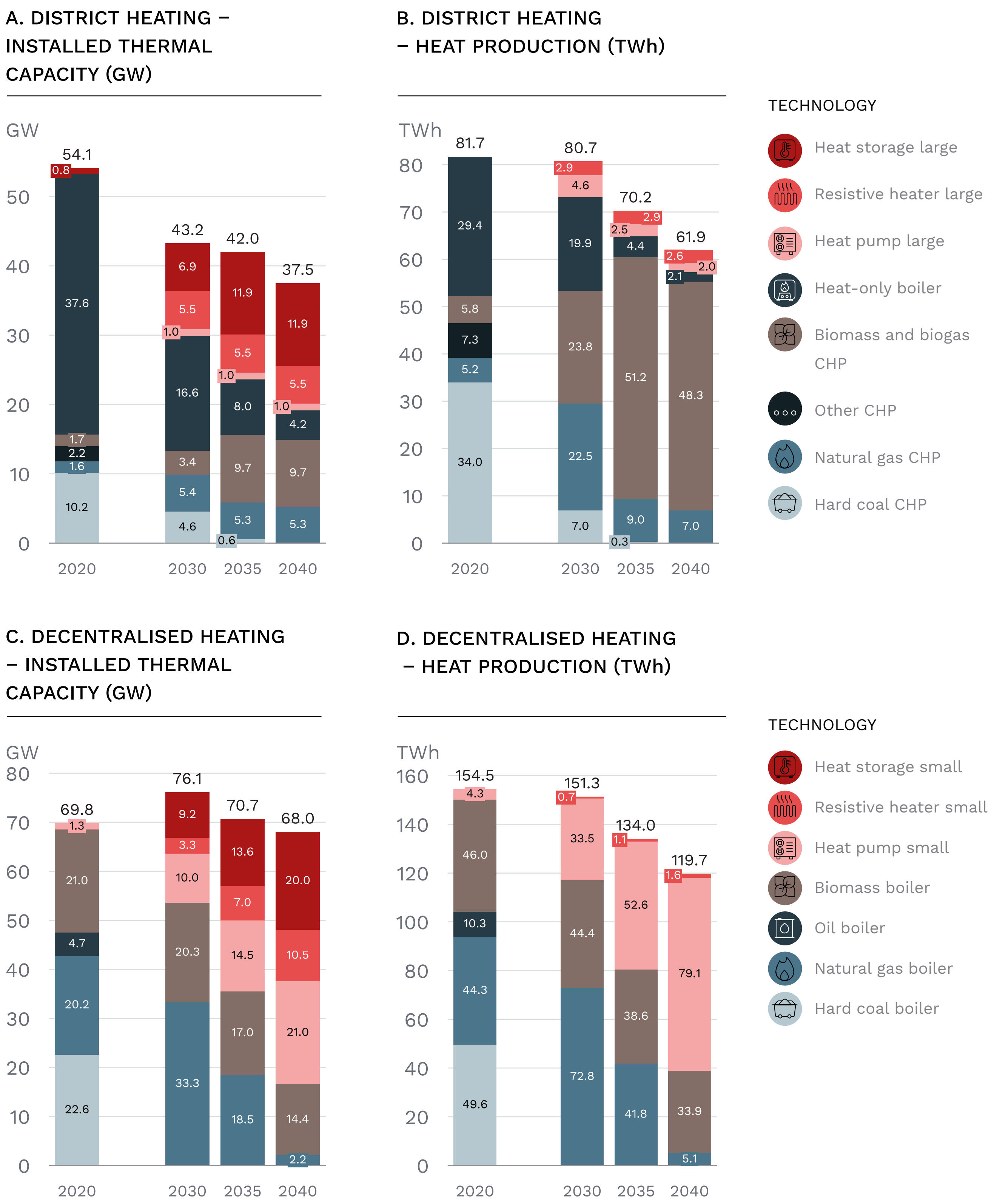


C. STRUCTURE OF DOMESTIC ELECTRICITY DEMAND (TWh)



Source: Instrat's own analysis. 2022 – historical data based on ARE. 2030-2040 – results of the PyPSA-PL optimisation model. Net capacity and production are shown, i.e. excluding the own demand of the conventional generating units. Electricity demand includes transmission and distribution losses.

FIGURE 6. Heating sector in the ambitious RES deployment scenario without nuclear power (S2)



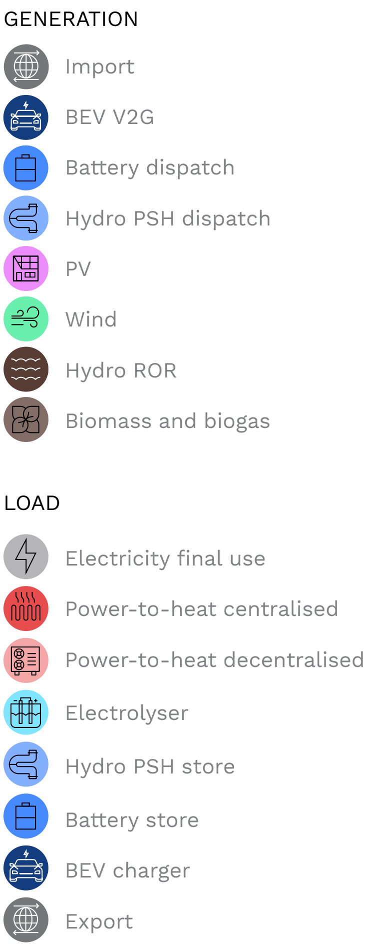
Source: Instrat's own analysis. 2020 – average of 2019-2021 historical data. Historical data for district heating based on ARE, URE, Forum Energii, and own assumptions; for decentralised heating based on GUS, Eurostat, and own assumptions. The historical installed capacity in decentralised heating is an estimate. 2030-2040 – results of the PyPSA-PL optimisation model. We assume that from 2030 onwards, heat-only boilers burn only natural gas. For decentralised heating, we assume that a small heat pump operates jointly with a peak resistive heater and heat storage (without fuel-fired boilers being separate systems). The shown thermal capacity of heat pumps should be interpreted as a temperature-independent peak heat output.

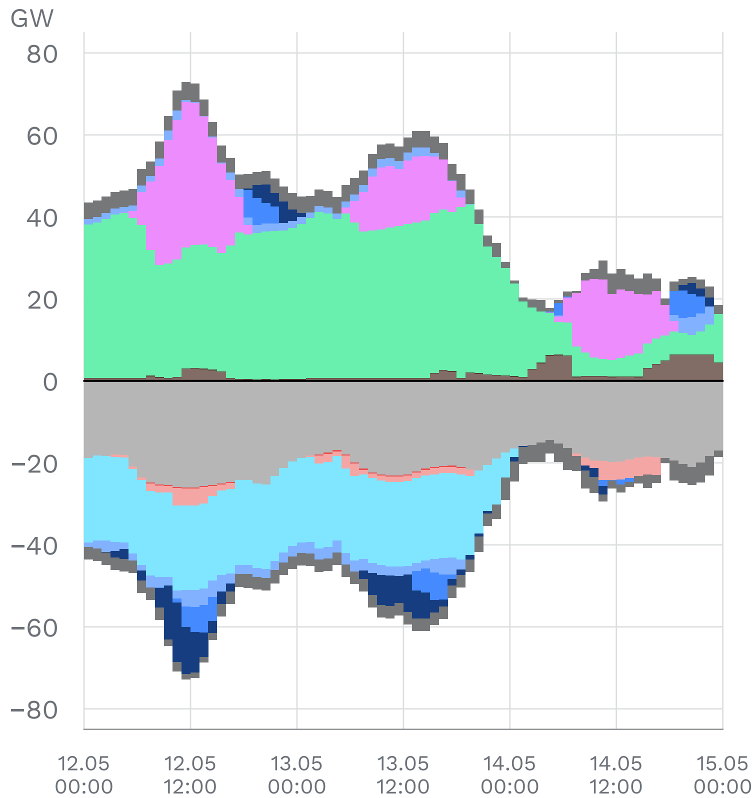
SELECTED PERIODS OF POWER SYSTEM OPERATION

LATE SPRING – FIGURE 7

In the first two days, system operation is similar to the S1 scenario (RES+NUC). The system relies on high production from wind and solar and is stabilised by dispatchable synchronous biomass or biogas power plants and pumped storage hydropower (PSH)[5]. During the evening hours, electric car batteries can cover part of the demand through V2G service. However, the third day is more challenging – given the low generation from wind, electrolysers have to be switched off, and biomass plants are switched on after dark.

FIGURE 7. Sample profile of electricity production and consumption in late spring 2040 (GW) in the ambitious RES deployment scenario without nuclear power (S2)





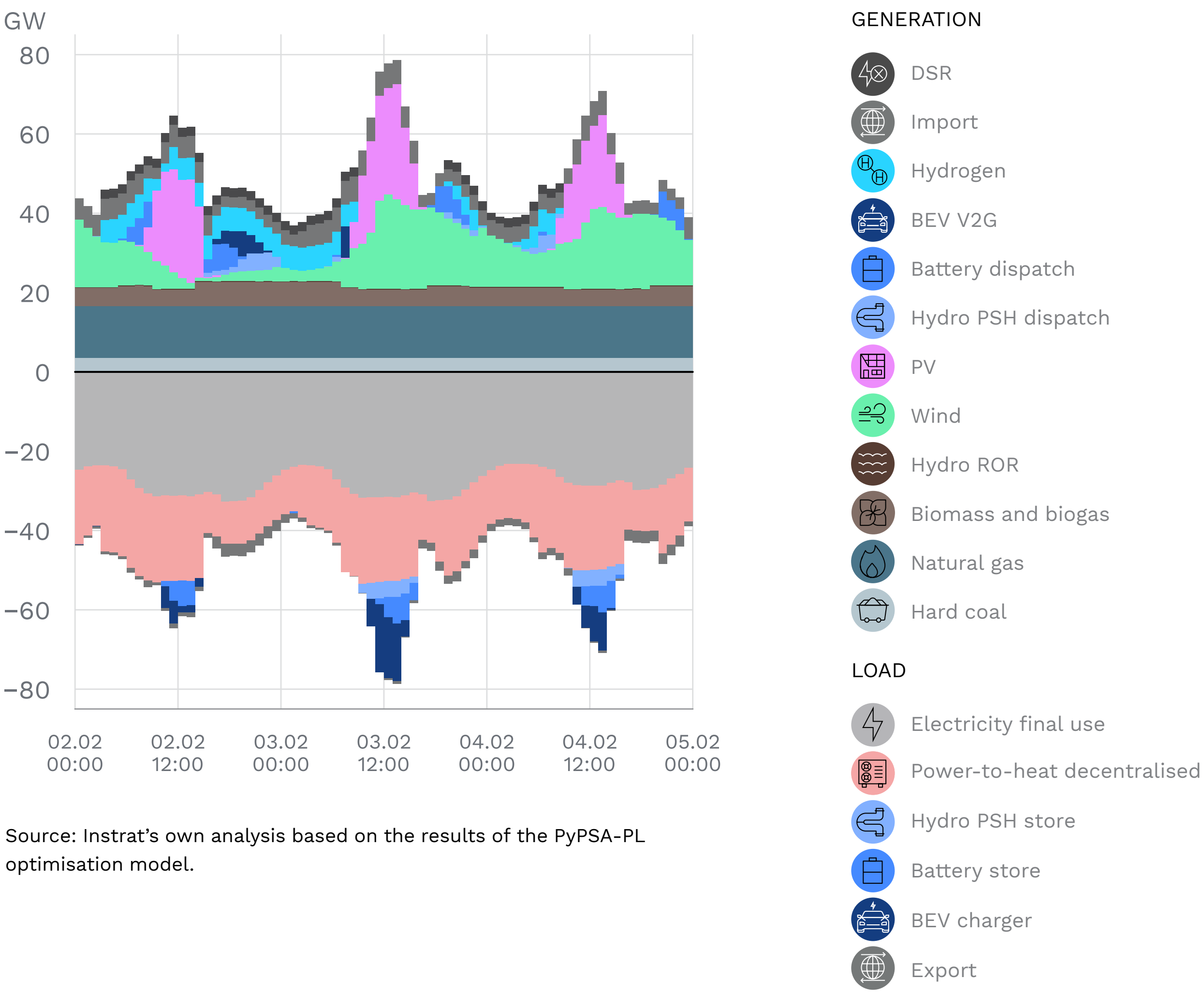
Source: Instrat's own analysis based on the results of the PyPSA-PL optimisation model.

5 Some domestic PSH units can pump water, while at the same moment some others can run it down to generate power. This may not seem economically justifiable, but it provides synchronous and dispatchable power, meets the power system inertia needs, etc., so it may be more cost-efficient than running a thermal power plant for regulation purposes only. Alternatively, PSH turbines operating at idle can be used as so-called synchronous compensators.

WINTER – FIGURE 8

The limited generation from wind and solar in February leaves a gap of around 20 GW of demand that has to be met by thermal power and CHP plants (gas, biogas and biomass, coal, and at some hours also hydrogen). Electrified residential heating puts a significant load on the power system. Residential heating and other energy storage and the partially flexible electricity demand of BEVs enable a good utilisation of solar power during the midday hours. In some particularly challenging hours, DSR services are triggered, allowing up to 2.3 GW of power not to be supplied at high remuneration to end consumers. A total of 200 GWh are not delivered throughout the year – the highest of all the scenarios analysed. It is more cost-efficient to pay remuneration for this volume than to keep additional peak capacity running for only around 100 hours per year.

FIGURE 8. Sample profile of electricity production and consumption in winter 2040 (GW) in the ambitious RES deployment scenario without nuclear power (S2)



Source: Instrat's own analysis based on the results of the PyPSA-PL optimisation model.

4.3. Scenario 3: baseline

In the baseline scenario (BASE), the maximum deployment of RES corresponds to the projections presented by the Ministry of Climate and Environment in June 2023 (MKiŚ, 2023). However, the maximum nuclear power deployment pace is delayed by two years compared to the official plans. This set of assumptions can be considered very optimistic regarding nuclear power deployment, moderately optimistic about offshore wind farms, and relatively pessimistic about solar power and onshore wind.

ELECTRICITY – FIGURE 9

In the baseline scenario, Poland's electricity sector is approaching decarbonisation in 2040 – by that year, we produce only 6% of electricity from fossil fuels.

However, the slower pace of change translates into higher emissions, both in the transition period and in 2040. The limited access to clean and cheap renewable energy reduces the profitability of electrification in other sectors.

Weather-dependent RES are the primary energy source in 2040, accounting for approximately 66% of annual electricity production. Offshore wind farms play a vital role in this scenario. It is profitable for all kinds of wind and solar installations to reach the highest capacity level allowed in the assumptions. This indicates that, even in 2040, there is not enough RES capacity in the system – increasing it could reduce the demand for natural gas and biogas in the electricity, heating, and industrial sectors. Extensive investment in the electricity grid would be required, but not as large as in the previous scenarios (S1 and S2). Compared to the Ministry of Climate and Environment projection, curtailed renewable energy is significantly lower due to greater system flexibility, (partial) demand optimisation, and slightly slower deployment of nuclear power plants.

Nuclear power plays relatively the most significant role in this scenario compared to the other pathways – it accounts for 16% of annual electricity production and leads to partial displacement of dispatchable biomass, biogas or natural gas-based capacities in the 2030s. It is also crucial in terms of providing inertia to the electricity system – in the baseline scenario, we assume that synchronous sources must always account for at least 15% of the generation mix in 2040. Nuclear power plants operate continuously, at least at the technical minimum.

The baseline scenario particularly relies on energy mega-projects related to implementing technologies currently non-existent in our technology mix (nuclear power plants, offshore wind farms). Delays in their implementation would, therefore, be especially costly.

The delayed deployment of clean energy sources makes the baseline scenario include a transition period with higher natural gas consumption. Moreover, due to the higher utilisation factor of fossil fuel power plants in the 2030s, building additional gas-fired units to replace carbon-intensive and expensive coal-fired power plants becomes cost-effective. Large investments in gas-fired generation infrastructure before 2030 make it unjustified to leave coal-fired power plants as a capacity reserve until 2040.

Without cheap energy from RES, electrification progresses more slowly. This is particularly evident in the heating and hydrogen sectors. Electrolysis-based hydrogen production is half as low as in the S1 scenario (section 5.4). The rapid development of the hydrogen economy, based on domestic production, is directly dependent on the growth of RES capacity in the electricity system.

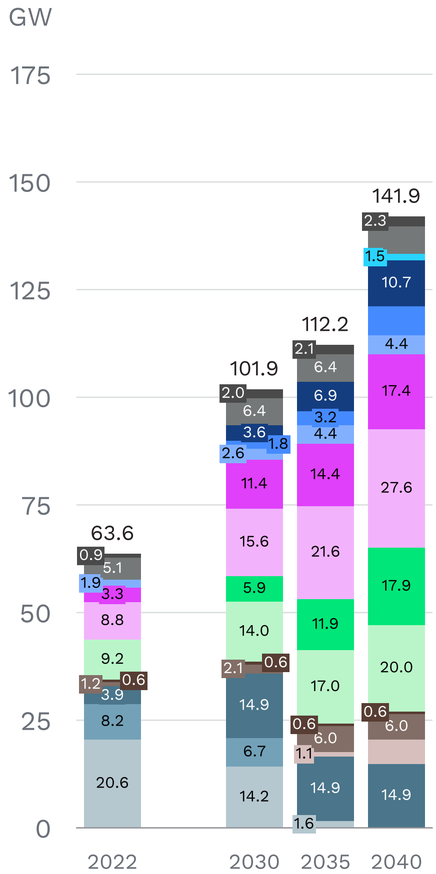
HEATING – FIGURE 10

In the baseline scenario, the transformation of district heating relies on the broad deployment of CHP technologies. In the late 2020s, gas-fired units rapidly replace coal-fired capacity. Already in the 2030s, fossil fuels are mainly used as a backup for bioenergy-based systems. Overall, heat demand is higher than in more ambitious scenarios due to lower insulation retrofit rates in buildings.

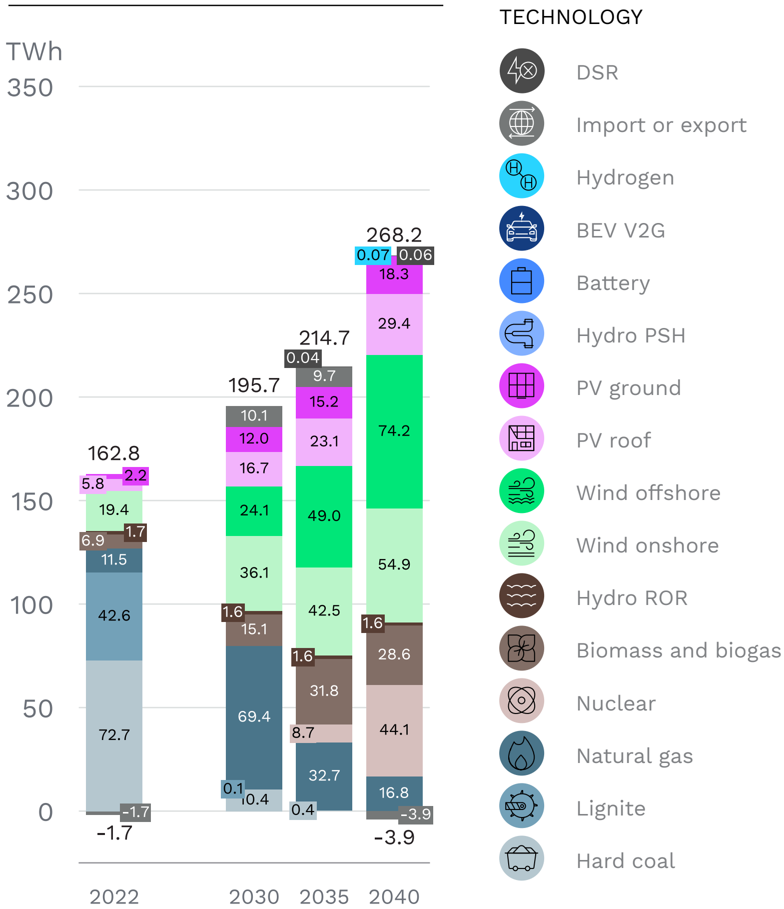
The lower availability of clean energy from RES significantly reduces the cost-efficiency of small heat pumps. Their capacity and annual generation are about 20% lower than in the ambitious scenario (RES+NUC) despite the higher overall heat demand, of which small heat pumps cover about 50%. Biomass boilers, as well as natural gas boilers (whose generation reaches a still non-negligible 28 TWh in 2040), meet the rest of the demand.

FIGURE 9. Electricity sector in the baseline scenario (S3)

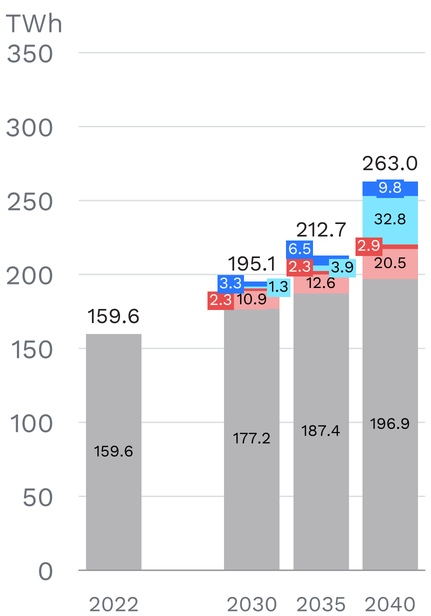
A. INSTALLED ELECTRICAL CAPACITY (GW)

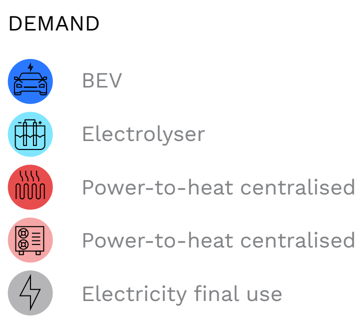


B. ELECTRICITY PRODUCTION AND EXCHANGE (TWh)



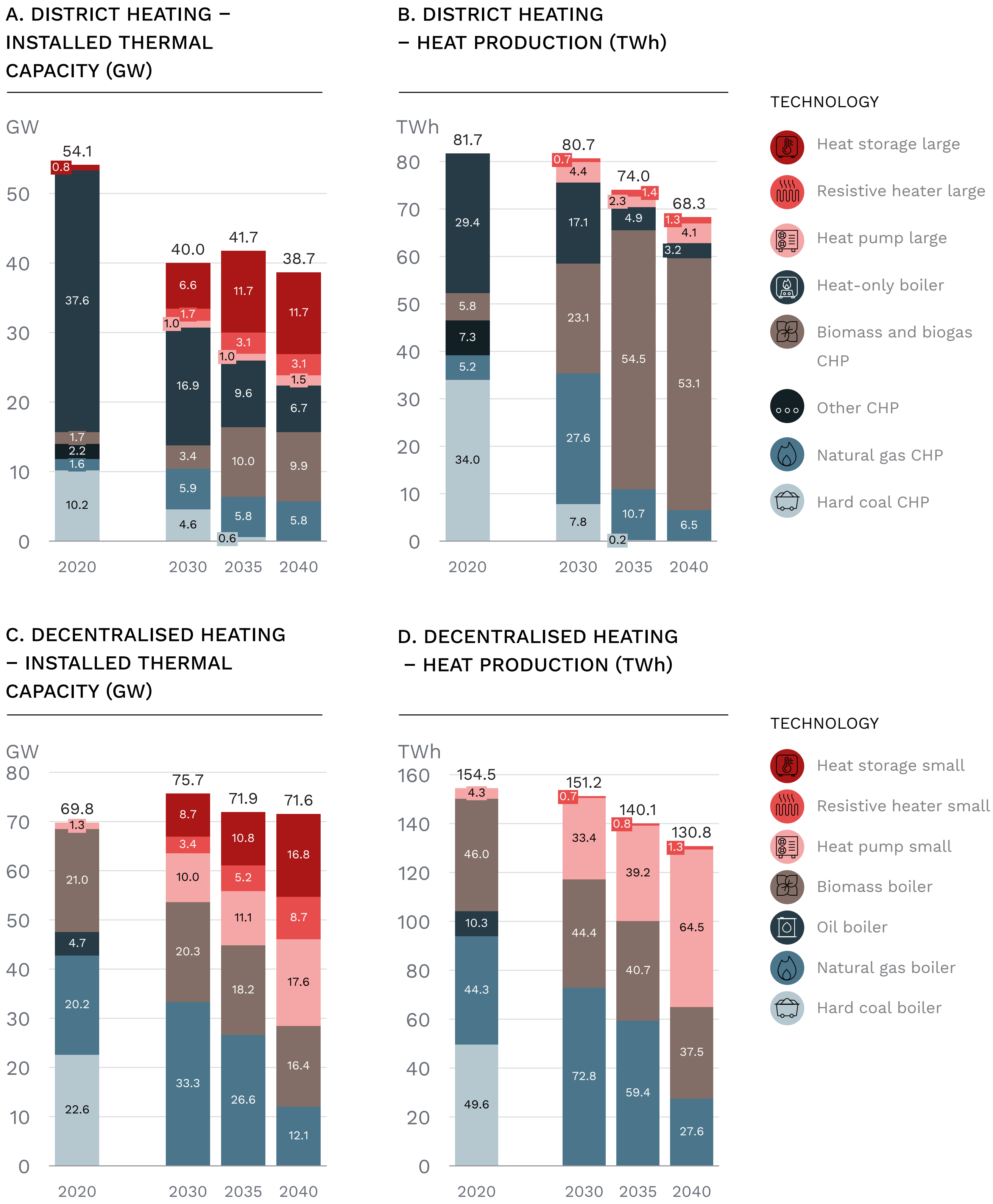
C. STRUCTURE OF DOMESTIC ELECTRICITY DEMAND (TWh)





Source: Instrat's own analysis. 2022 – historical data based on ARE. 2030-2040 – results of the PyPSA-PL optimisation model. Net capacity and production are shown, i.e. excluding the own demand of the conventional generating units. Electricity demand includes transmission and distribution losses.

FIGURE 10. Heating sector in the baseline scenario (S3)



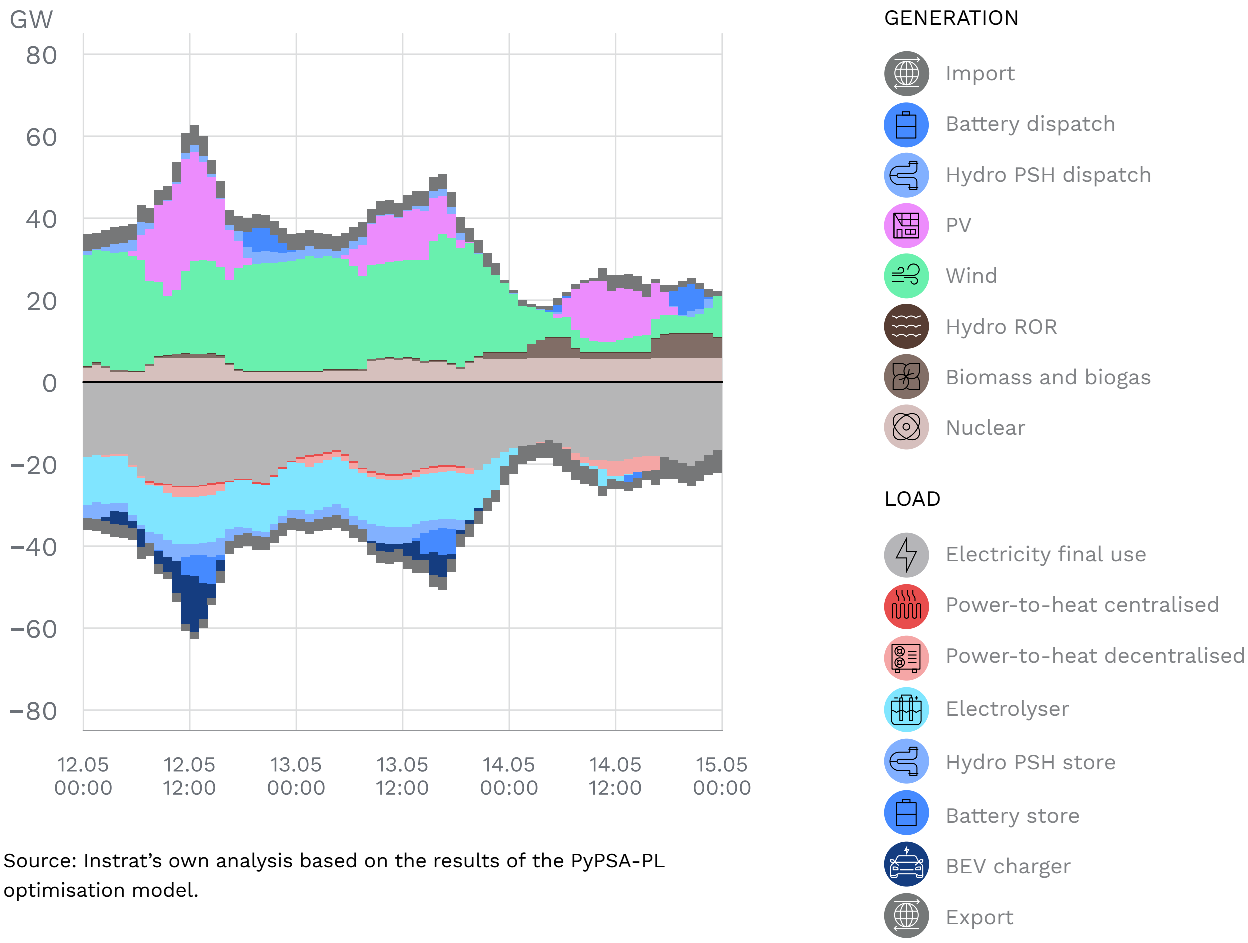
Source: Instrat's own analysis. 2020 – average of 2019-2021 historical data. Historical data for district heating based on ARE, URE, Forum Energii, and own assumptions; for decentralised heating based on GUS, Eurostat, and own assumptions. The historical installed capacity in decentralised heating is an estimate. 2030-2040 – results of the PyPSA-PL optimisation model. We assume that from 2030 onwards, heat-only boilers burn only natural gas. For decentralised heating, we assume that a small heat pump operates jointly with a peak resistive heater and heat storage (without fuel-fired boilers being separate systems). The shown thermal capacity of heat pumps should be interpreted as a temperature-independent peak heat output.

SELECTED PERIODS OF POWER SYSTEM OPERATION

LATE SPRING – FIGURE 11

In the baseline scenario, on windy and sunny days in 2040, our system relies almost entirely on renewables. It is stabilised by nuclear power, and the demand flexibility is significantly improved by hydrogen production, although the electrolysers have a lower capacity than in the ambitious RES scenarios (additional electrolysers are not yet cost-effective). Even when wind weakens, the system can rely on the operation of clean nuclear power and bioenergy, as well as energy storage charged during sunny hours. This will mainly be possible in the warm months of the year – the electrification of heating will exacerbate the differences in power demand between summer and winter.

FIGURE 11. Sample profile of electricity production and consumption in late spring 2040 (GW) in the baseline scenario (S3)

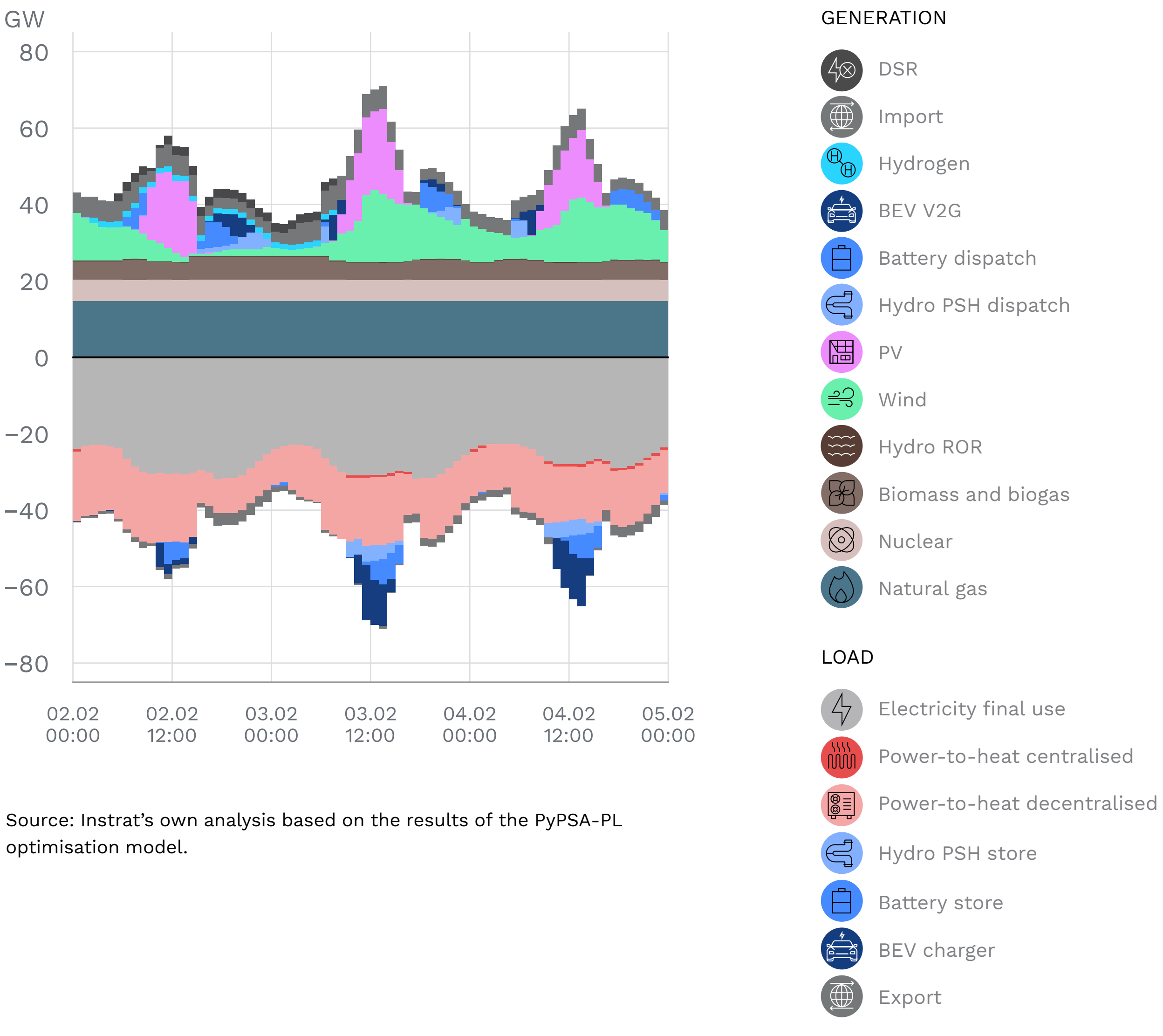


Source: Instrat's own analysis based on the results of the PyPSA-PL optimisation model.

WINTER – FIGURE 12

On less windy February nights, the system relies primarily on a combination of dispatchable units – nuclear, bioenergy, and gas – used at full capacity. However, even in such an unfavourable period, RES generating electricity at certain hours can play an important role in combination with heat and electricity storage. As this scenario puts constraints on onshore wind power development, we see that even the more windy winter days still see significant use of carbon-intensive natural gas.

FIGURE 12. Sample profile of electricity production and consumption in winter 2040 (GW) in the baseline scenario (S3)



Source: Instrat's own analysis based on the results of the PyPSA-PL optimisation model.

4.4. Scenario 4: slow transition

The energy transition pathways described earlier presume intensive and effective state actions supporting RES deployment. A prerequisite for their implementation is also a positive attitude to change among local authorities and investors. Poland's slower energy transition remains a real risk without this unprecedented mobilisation.

In the slow transition scenario (SLOW), large-scale projects are implemented too slowly, and the deployment of distributed energy sources loses momentum due to technical grid limitations and an unfavourable legal environment.

ELECTRICITY – FIGURE 13

Nevertheless, the S4 scenario is still a transition path – in 2040, weather-dependent RES account for more than half of annual electricity generation. The Polish power system has about 36 GW of solar and 26 GW of wind power (the optimum solution is to deploy these energy sources at the maximum rate allowed by the scenario assumptions). Even in the best weather, stabilising these clean energy sources requires the continuous, significant operation of synchronous conventional power plants (at least 25% of instantaneous production in 2040). Regarding flexibility, such a power system is not much different from the current one in Poland.

The slow transition scenario means a high level of natural gas, biomass, and biogas use even in 2040. Coal appears in the electricity mix for the last time in 2030. As fossil fuel power plants keep a relatively high utilisation factor throughout the 2030s, building as much as almost 18 GW of gas-fired capacity is cost-effective. Changes in gas-fired capacity would occur even faster, but we have assumed an upper limit for the investment rate in this technology[6]. Extending the life of coal-fired power generation would, in principle, be possible, e.g. for political reasons, but would involve further increases in costs and emissions. The utilisation factor of gas-fired capacity is gradually declining thanks to the deployment of RES and the first nuclear units being connected to the grid. Despite the above, in 2040 electricity generation from natural gas still reaches 34.2 TWh.

The Polish electricity system often relies on cheaper energy purchased from neighbouring countries. Our electricity trade balance is at its lowest in 2030, but even in 2040, net imports amount to 12.6 TWh. The ability to import electricity reduces systemic costs and emissions but comes at the price of outgoing cash flows – we are helping our neighbours repay their RES investments rather than using these funds for our domestic projects.

6 The construction of a large number of gas-fired power plants in a short period of time can face barriers related to the availability of contractors, trained staff, the operational capacity of investors, etc.

Slow RES deployment limits the electrification of sectors. Electricity demand across the economy reaches 221 TWh, compared to 309 TWh in the ambitious S1 scenario (RES+NUC). In comparison to the S1 scenario, we see a 38% lower electricity demand from small heat pumps and resistive heaters. The use of electricity for district heating diminishes by more than three times, and electrolysis-based hydrogen production is marginal even in 2040 (less than 4 TWh of electricity demand for electrolysis against almost 64 TWh in the S1 scenario). This confirms the claim that the hydrogen economy strongly depends on the rapid growth of emission-free energy sources with low variable costs.

HEATING – FIGURE 14

The slow transition scenario (S4) assumes a slow pace of insulation retrofits in buildings, leading to high heat demand. The annual production of heat reaches 227 TWh, compared to 181 TWh in the RES+NUC scenario.

In district heating, most heat is produced by CHP units (mainly fossil fuel-based in 2030, later using biomass or biogas – assuming the scalability of those solutions). The system also retains significant heat-only capacities, which are used less frequently. The capacity of heat-only boilers is higher than in the other scenarios due to the assumption of limited heat storage capacity in district heating systems.

The slow transition in the electricity sector limits the economic viability of small heat pumps – they account for 36% of heat production in 2040. Natural gas boilers remain the primary source of decentralised heating in buildings, although their use gradually declines in the 2030s. The use of biomass in decentralised heating remains similar to that in 2020 throughout the period considered.

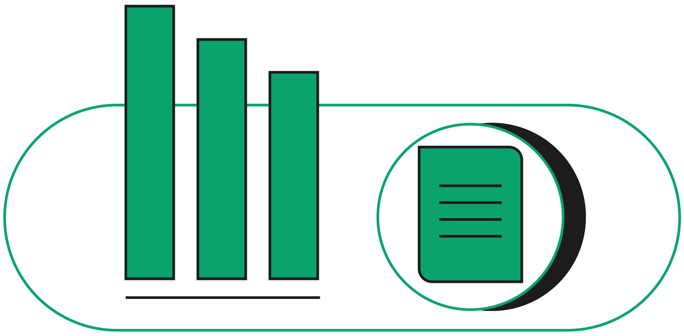
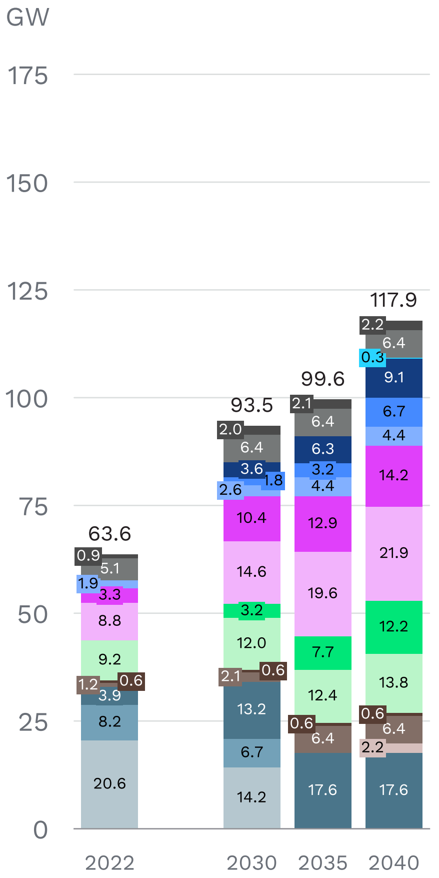
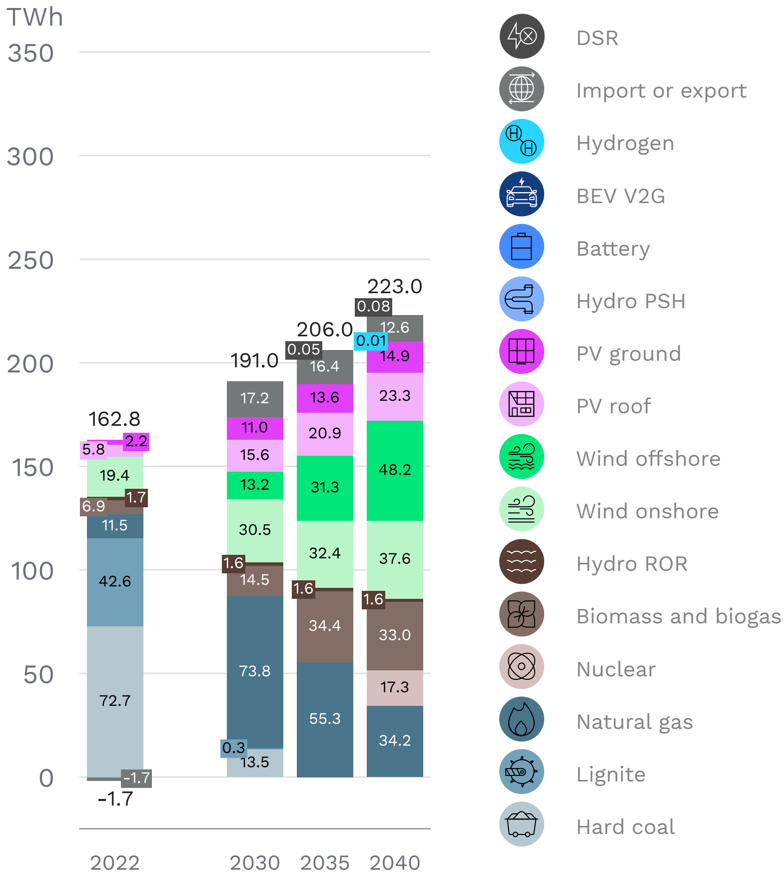


FIGURE 13. Electricity sector in the slow transition scenario (S4)

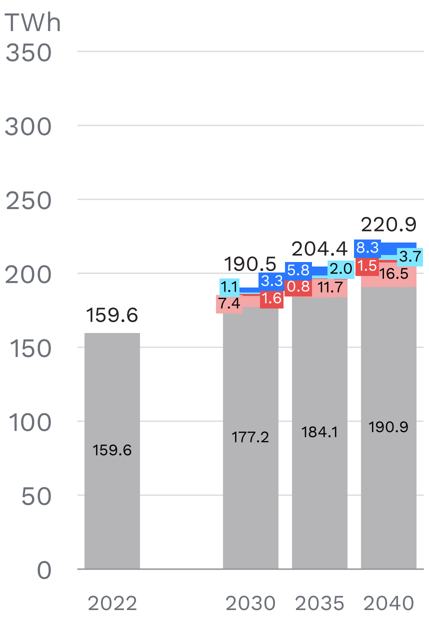
A. INSTALLED ELECTRICAL CAPACITY (GW)

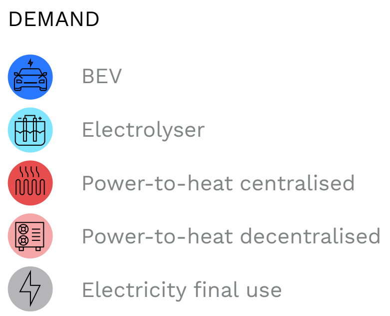


B. ELECTRICITY PRODUCTION AND EXCHANGE (TWh)



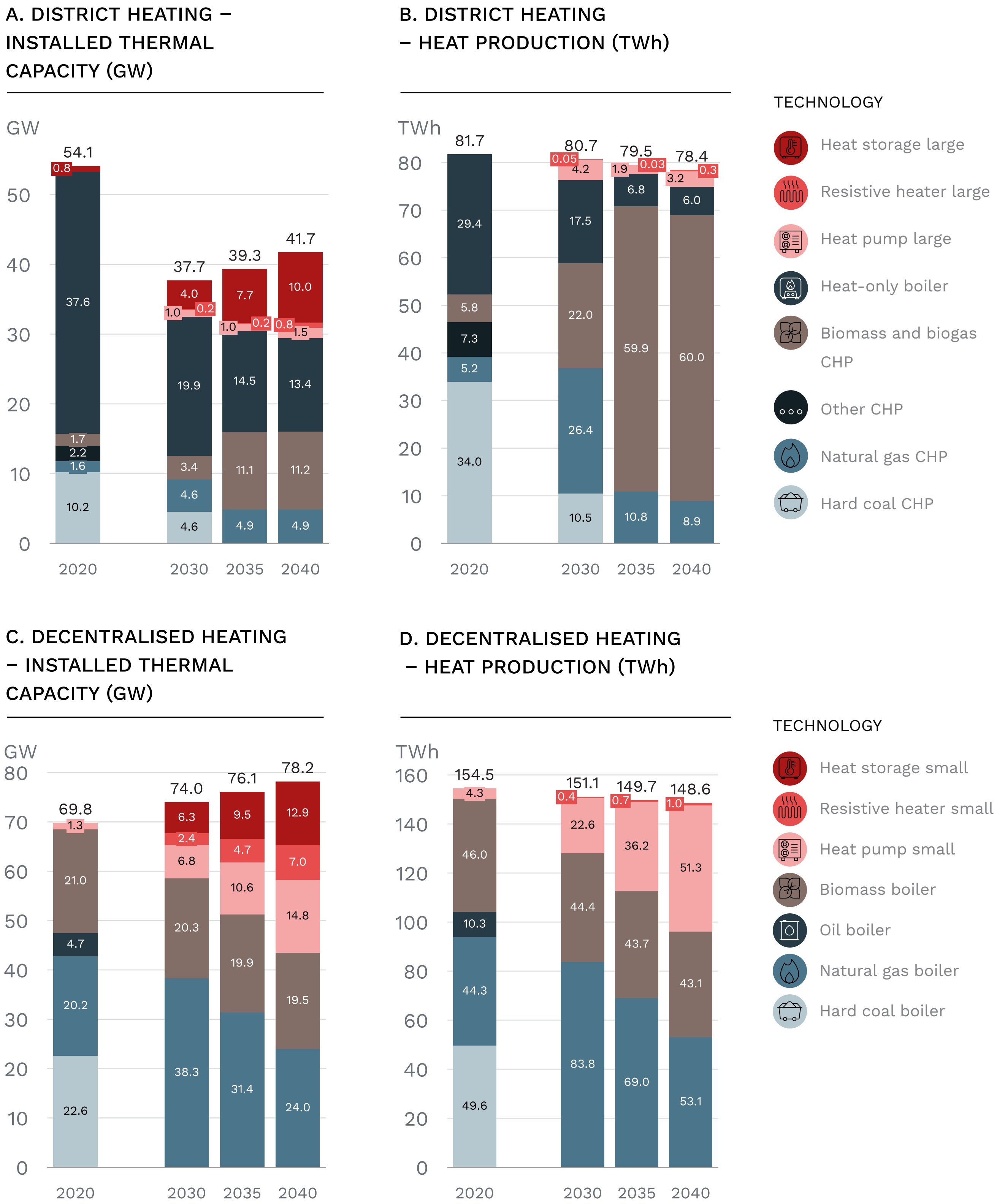
C. STRUCTURE OF DOMESTIC ELECTRICITY DEMAND (TWh)





Source: Instrat's own analysis. 2022 – historical data based on ARE. 2030-2040 – results of the PyPSA-PL optimisation model. Net capacity and production are shown, i.e. excluding the own demand of the conventional generating units. Electricity demand includes transmission and distribution losses.

FIGURE 14. Heating sector in the slow transition scenario (S4)



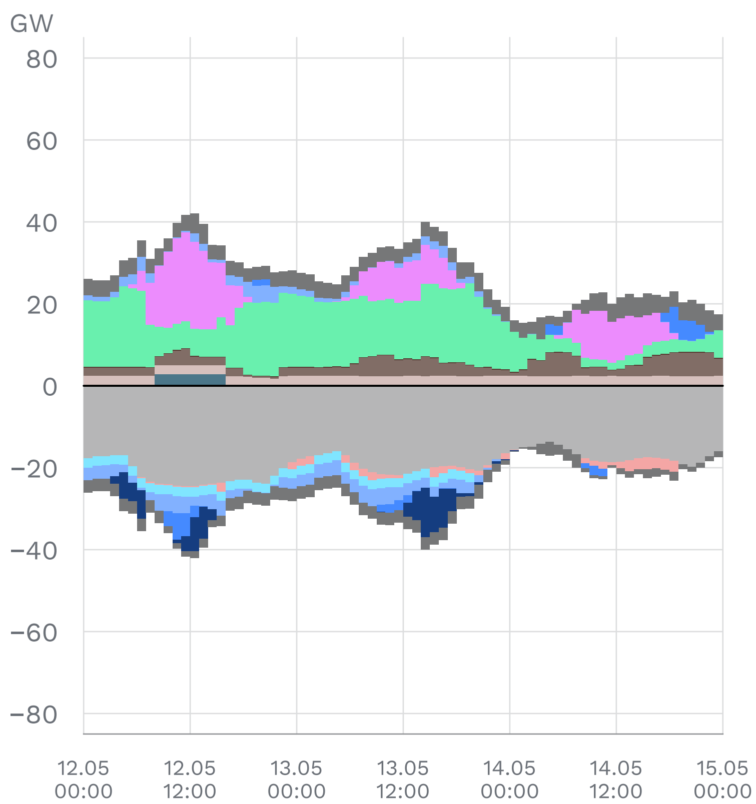
Source: Instrat's own analysis. 2020 – average of 2019-2021 historical data. Historical data for district heating based on ARE, URE, Forum Energii, and own assumptions; for decentralised heating based on GUS, Eurostat, and own assumptions. The historical installed capacity in decentralised heating is an estimate. 2030-2040 – results of the PyPSA-PL optimisation model. We assume that from 2030 onwards, heat-only boilers burn only natural gas. For decentralised heating, we assume that a small heat pump operates jointly with a peak resistive heater and heat storage (without fuel-fired boilers being separate systems). The shown thermal capacity of heat pumps should be interpreted as a temperature-independent peak heat output.

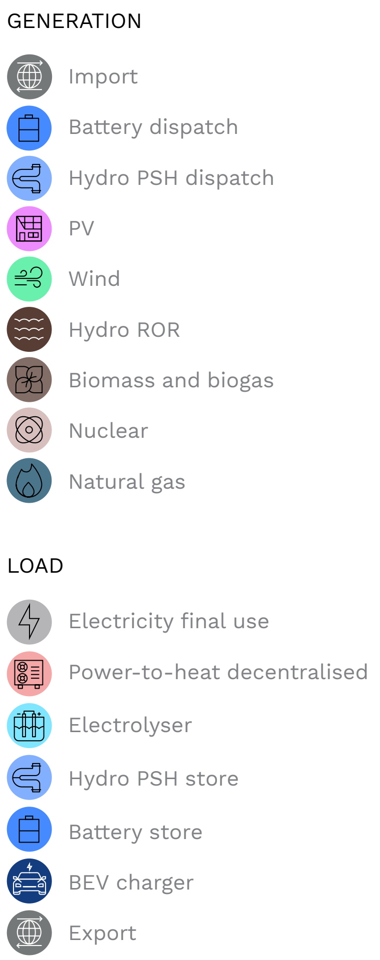
SELECTED PERIODS OF POWER SYSTEM OPERATION

LATE SPRING – FIGURE 15

During the analysed period in May, the Polish power system is coping mainly without the contribution of CO_2-emitting capacities. Most of the production comes from wind and solar. Poland's first nuclear power plants are operating at the system's base. The variable nature of the operation of bioenergy power plants is due to the need to complement variable generation from weather-dependent RES and to ensure at least a 25% share of dispatchable synchronous sources at times of high RES generation. On the demand side, the electricity available to power the electrolysers remains low even on windy and sunny days. Charging batteries (including those of BEVs) and pumping water in PSH plants play a more prominent role.

FIGURE 15. Sample profile of electricity production and consumption in late spring 2040 (GW) in the slow transition scenario (S4)



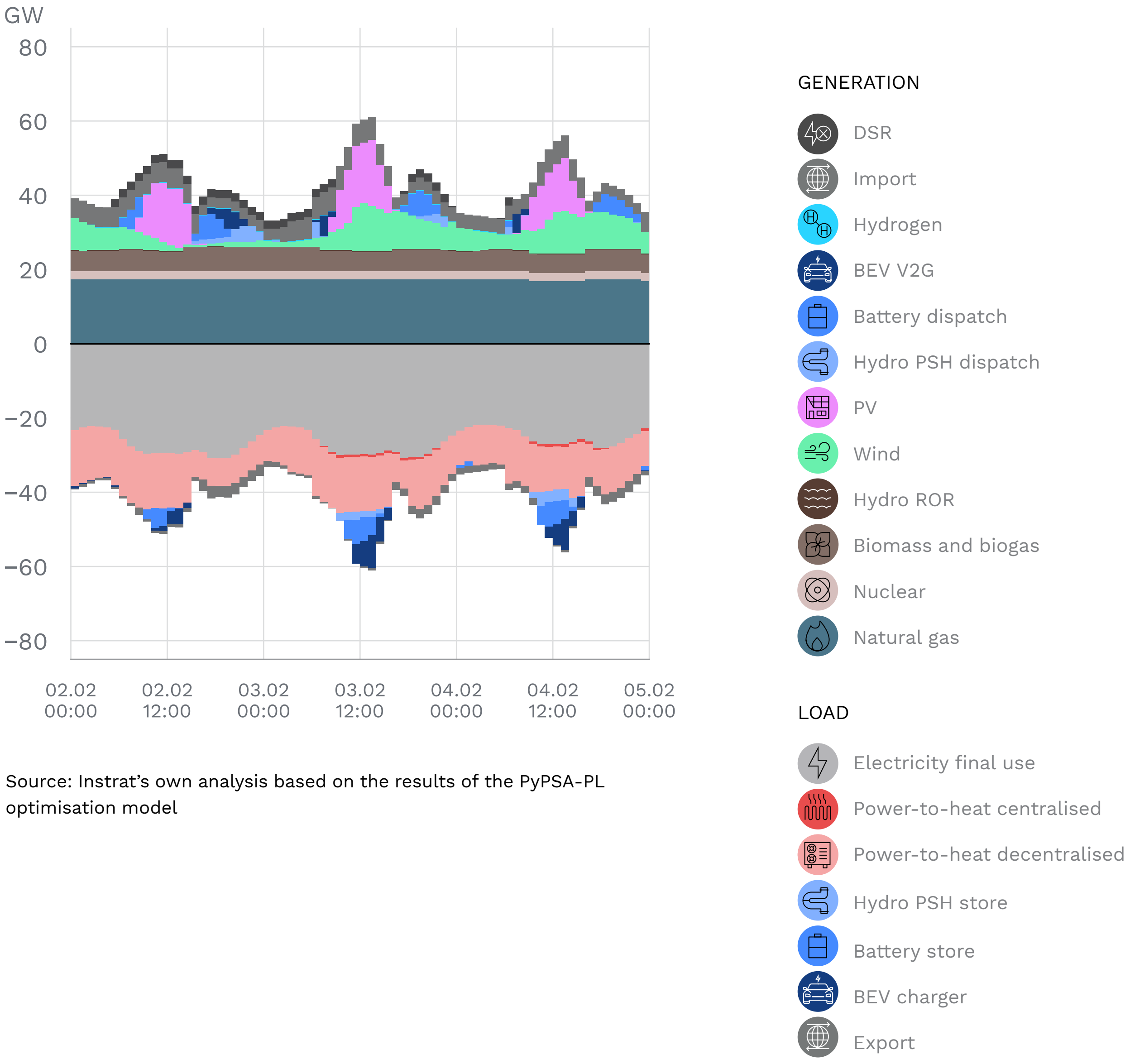


Source: Instrat's own analysis based on the results of the PyPSA-PL optimisation model.

WINTER – FIGURE 16

During the challenging period in February, our gas, nuclear, biomass and biogas power plants operate at almost maximum available capacity. The system is also significantly supported by imported electricity. At rare moments of higher generation from RES, the electricity demand from residential heat pumps and resistive heaters (supplying heat to heat storage), electric cars, and storage technologies is increasing. At certain times, additional electricity is so hard to provide that it becomes cost-effective to use a DSR service (remunerated reduction of electricity consumption by end users – a total of only 80 GWh of electricity per year is not delivered).

FIGURE 16. Sample profile of electricity production and consumption in winter 2040 (GW) in the slow transition scenario (S4)



Source: Instrat's own analysis based on the results of the PyPSA-PL optimisation model

4.5. Comparison of CO_2 emissions, fuel consumption, and system costs between scenarios

CO_2 EMISSIONS

The ambitious RES and nuclear power deployment scenario (S1) achieves the best outcome from a climate protection perspective. Emissions from the energy use of fossil fuels (including hydrogen production), compared to approximately 294 million tonnes CO_2 in 2020[7], differ in each scenario (Figure 17):

- ambitious RES and nuclear power deployment scenario (S1) – 93 million tonnes CO_2 in 2040 (68% reduction),
- ambitious RES deployment scenario without nuclear power (S2) – annual emissions are only slightly higher than S1 at 99 million tonnes CO_2 in 2040 (66% reduction),
- baseline scenario (S3) – 116 million tonnes CO_2 in 2040 (61% reduction),
- slow transition scenario (S4) – emissions are as high as 141 million tonnes CO_2 in 2040 (52% reduction).

All scenarios involve a significant decrease in annual energy-related emissions. However, only those focusing on rapid RES deployment (S1, S2) allow Poland to come close to EU's emission reduction targets.

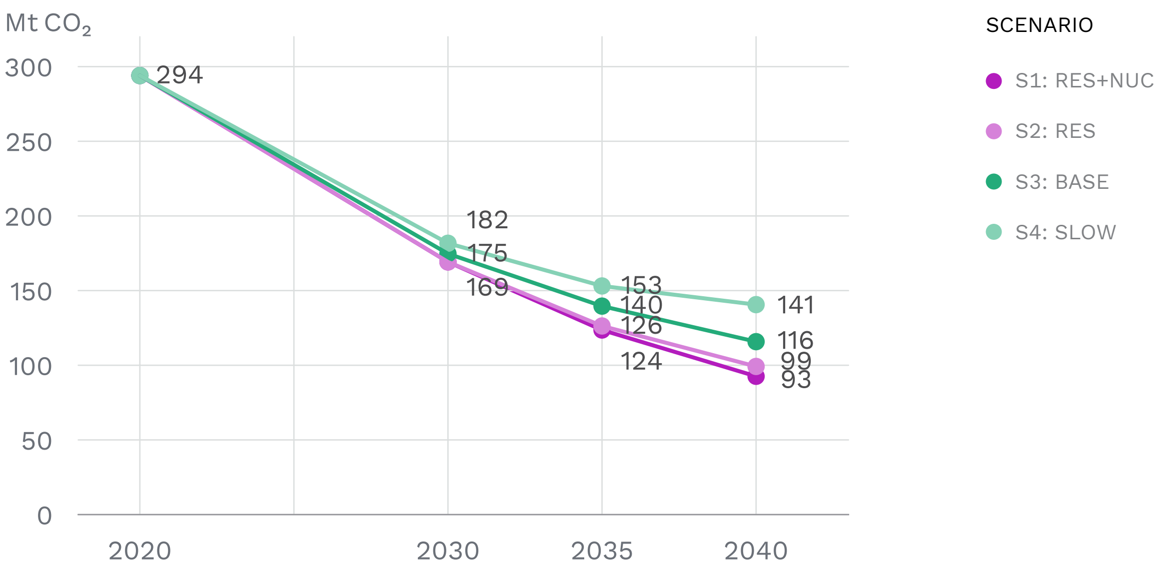
According to the Kyoto Protocol, the base year for setting emission reduction targets for Poland is 1988[8]. Our modelling considers (directly or indirectly) sectors accounting in 2020 for about 75% of total annual GHG emissions in Poland. If we assume that emissions from the sectors we analyse also accounted for 75% of the total in the base year 1988, then relative to the base year 1988, the decrease in emissions in 2040 in the S1 scenario is about 80% (for the S2 scenario it is 77%). In practice, however, decarbonisation in other sectors may be slower.

7 The value provided for 2020 is an average from the 2019-2021 reference period. The total greenhouse gas emissions in 2019-2021 amounted on average to 386 million tonnes of CO_2-equivalent annually (KOBiZE, 2023).

8 In 1988, Poland emitted 578 million tonnes of CO_2-equivalent (KOBiZE, 2023).

Work is currently underway to agree on the EU emission reduction target for 2040. The proposed target is 90% at the EU level (ESABoCC, 2023). This number is not directly achievable in Poland in the ambitious transition scenarios. However, specific challenges (large share of energy-intensive industry in GDP, high heating needs, small hydropower potential) and delays must be considered when setting targets for Poland. Therefore, scenarios S1 and S2 would still be an ambitious contribution to the EU's climate policy[9].

FIGURE 17. Annual CO_2 emissions from energy use of fossil fuels and hydrogen production (Mt CO_2)



Source: Instrat's own analysis. 2020 – average of 2019-2021 historical data based on KOBiZE, Eurostat, and own assumptions. 2030-2040 – numbers based on the PyPSA-PL model results and assumptions on emissions associated with the unmodelled energy use of fossil fuels.

In 2020, electricity, district heating, and decentralised heating generated the majority of energy-related CO_2 emissions (around 60%). In the S1 scenario, their share could fall to 6% (Figure 14). In absolute terms, this is a drop from around 180 million tonnes of CO_2 to only 6 million tonnes of CO_2. In the 2030s, efforts to reduce emissions from the use of fossil fuels in heavy transport and industry for energy purposes (e.g. high-temperature heat production) or for process purposes (e.g. cement production – process emissions, however, do not count towards the values presented in this report) will therefore become increasingly important. These are so-called hard-to-abate sectors.

9 A more detailed modelling of energy demand for fossil fuels outside the sectors represented in PyPSA-PL could indicate even greater potential for emission reductions.

According to our analyses, individual transport in Poland may also be such a sector. **Replacing more than 20 million active ICE cars with electric cars (BEV) is a challenge for decades**, given that new car registrations do not exceed 400 000 annually (PZPM, 2023). Despite the assumption of declining demand for this type of mobility in scenarios S1 and S2 (e.g. as a result of the promotion of public transport) and the ambitious growth rate of the BEV fleet, emissions from the light vehicle sector in 2040 amount to approx. 32 million tonnes CO_2, a decrease of only around 20% relative to 2020 (see Figure 18).

FUEL CONSUMPTION

In all scenarios, the demand for thermal coal (i.e. used to produce energy) falls sharply – already in the 2030 perspective (Figure 19A). This demand in scenarios S1 and S2 falls from 1 700 PJ (approx. 80.2 million tonnes of hard coal equivalent[10]) in 2020 to 300 PJ (14.2 million tonnes) in 2030. Even this estimate may be overestimated if natural gas displaces hard coal from the sectors that are not directly modelled, just as that happens in the electricity and district heating sectors.

In the directly modelled sectors, the demand for hard coal in 2030 in scenarios S1 and S2 is only about 105 PJ in the electricity sector (5 million tonnes). Scenarios S3 and S4 have marginally higher demand. The shift away from coal is dictated by the increasing cost of CO_2 allowances, resulting in its displacement by renewables; or, if not possible, by natural gas, which is characterised by lower emissions per unit of energy.

Demand for natural gas increases successively in all scenarios until 2030, after which it decreases (Figure 19B). The peak consumption in 2030 ranges from 1 090 PJ (30 bcm in high-methane gas equivalent[11]) in scenarios S1 and S2 to 1 240 PJ (34 bcm) in scenario S4. Already in 2035, gas demand falls in scenarios S1 and S2 to today's level of 680 PJ (about 19 bcm) or even lower.

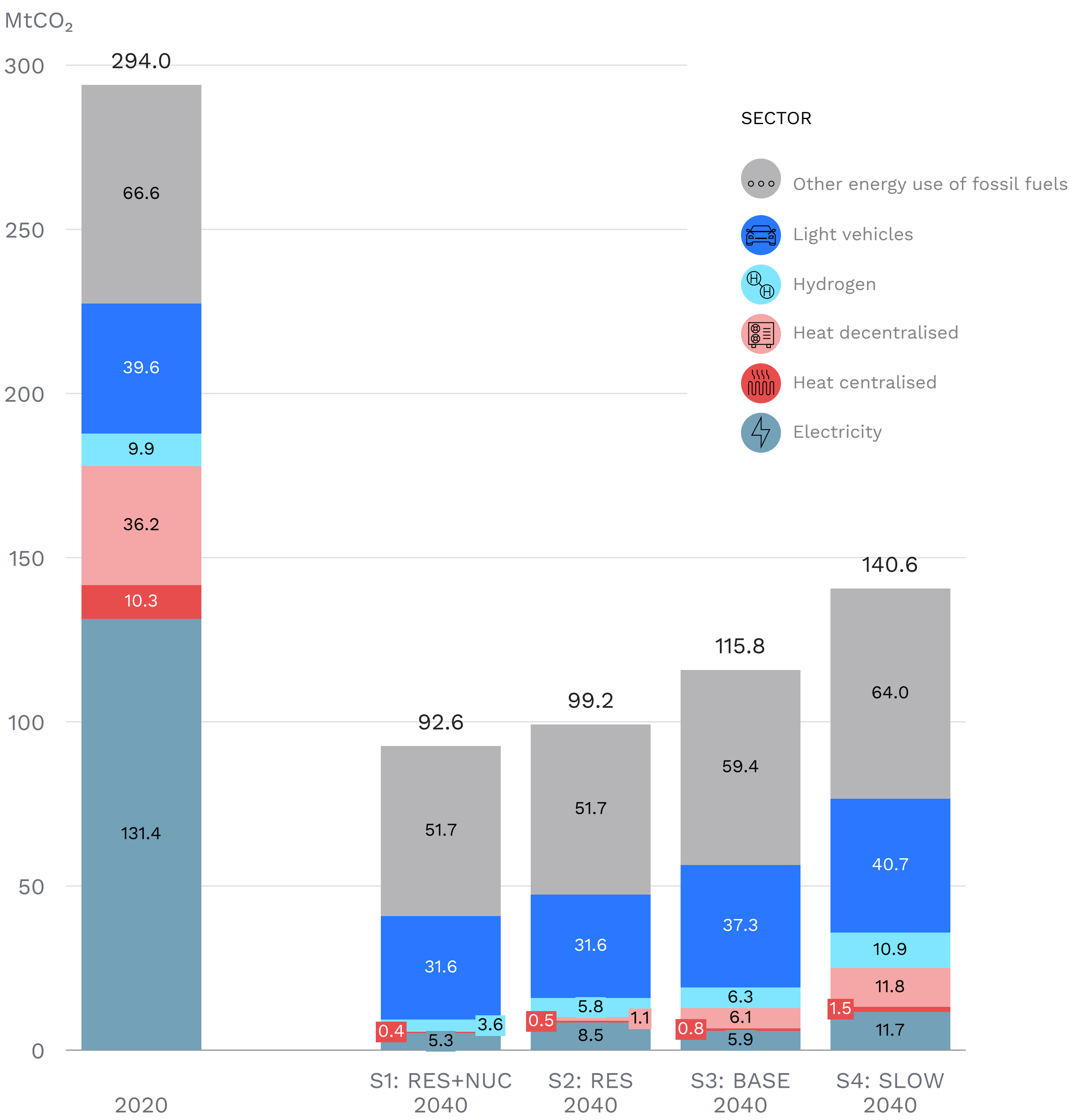
The decline continues in subsequent years as well. One of the main challenges of decarbonisation in the 2040s will be maintaining this decline rate by replacing natural gas with so-called green gases such as biomethane or hydrogen from electrolysis.

10 Assuming the lower calorific value of hard coal of 21.2 MJ/kg.

11 Assuming the lower calorific value of high-methane gas of 36.6 MJ/m3.

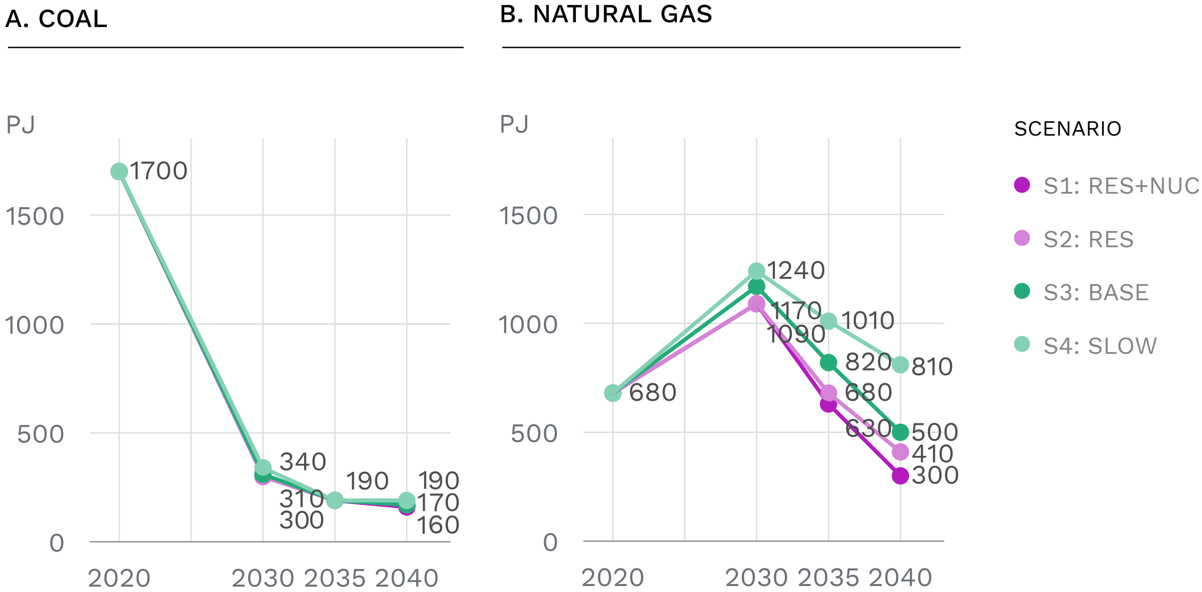
FIGURE 18. CO_2 emissions from fossil fuel energy use and hydrogen production in 2040 (Mt CO_2).

Electricity and district heating are decarbonised to a great extent by 2040. Other sectors are becoming a priority for decarbonisation policy.



Source: Instrat's own analysis. 2020 – average of 2019-2021 historical data based on KOBiZE, Eurostat, and own estimates. Total annual average emissions amounted in that period to 386 Mt CO_2. 2040 – numbers based on PyPSA-PL model results. Emissions from combined heat and power (CHP) plants (producing both electricity and system heat) were included in the electricity sector emissions. Emissions from other energy uses of fossil fuels (such as decentralised heat demand in industry and agriculture, and heavy road, water and air transport) are not represented in the PyPSA-PL model – they are an assumption coupled with assumptions about the demand for energy carriers (the reduction in unmodelled emissions comes at the expense of increased demand for electricity and hydrogen).

FIGURE 19. Coal and natural gas consumption for energy use and hydrogen production (PJ)



Source: Instrat's own analysis. 2020 – historical data based on Eurostat, KOBiZE, and own assumptions. 2030-2040 – calculations based on PyPSA-PL model results and assumptions on unmodelled energy-related fuel use.

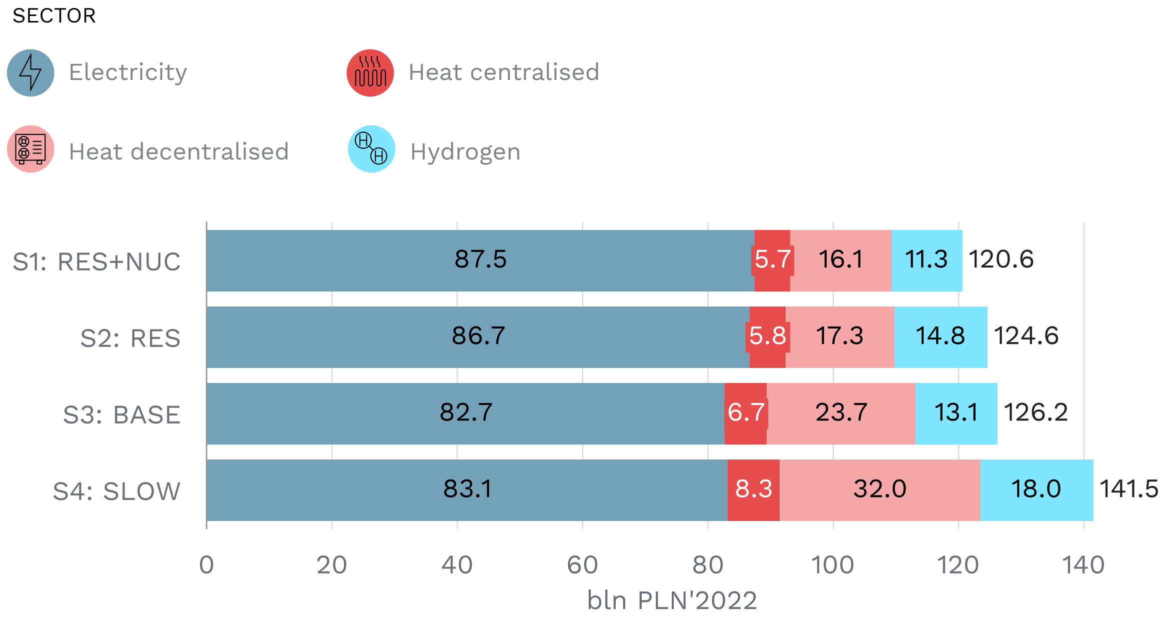
SYSTEM COSTS

The ambitious RES and nuclear power deployment scenario (S1) achieves the lowest annual system costs among the considered scenarios. In 2040, they amount to approximately PLN 121 billion – these costs include the annual coverage of electricity, heat, and hydrogen demand (Figure 16). Relative to the S3 scenario, the S1 scenario is cheaper by approximately PLN 6 billion per year, and relative to the S4 scenario by up to PLN 21 billion per year. This is mainly due to a reduction in heating costs.

Annual system costs are subject to optimisation in the PyPSA-PL model. By system costs, we mean the annual operating costs (OPEX) of generating, converting, and storing all modelled energy carriers – these include the costs of purchasing fuel and CO_2 emission allowances[12] (variable costs), as well as fixed infrastructure maintenance costs. In addition, we include the investment cost converted into annual installments (annuitised CAPEX). We provide a full decomposition of annual system costs by technology and the total overnight investment costs in Appendix C. However, we do not include costs associated with extending and maintaining electricity grids – these would be highest in the ambitious S1 and S2 scenarios.

12 We also attribute a cost to CO_2 emissions resulting from activities that (at least currently) are not covered by the ETS, as every tonne of CO_2 emitted into the atmosphere can be associated with the so-called social cost of carbon (Rennert et al., 2022).

FIGURE 20. Annual system cost in 2040 decomposed into electricity, heating and hydrogen sectors (billion PLN'2022)



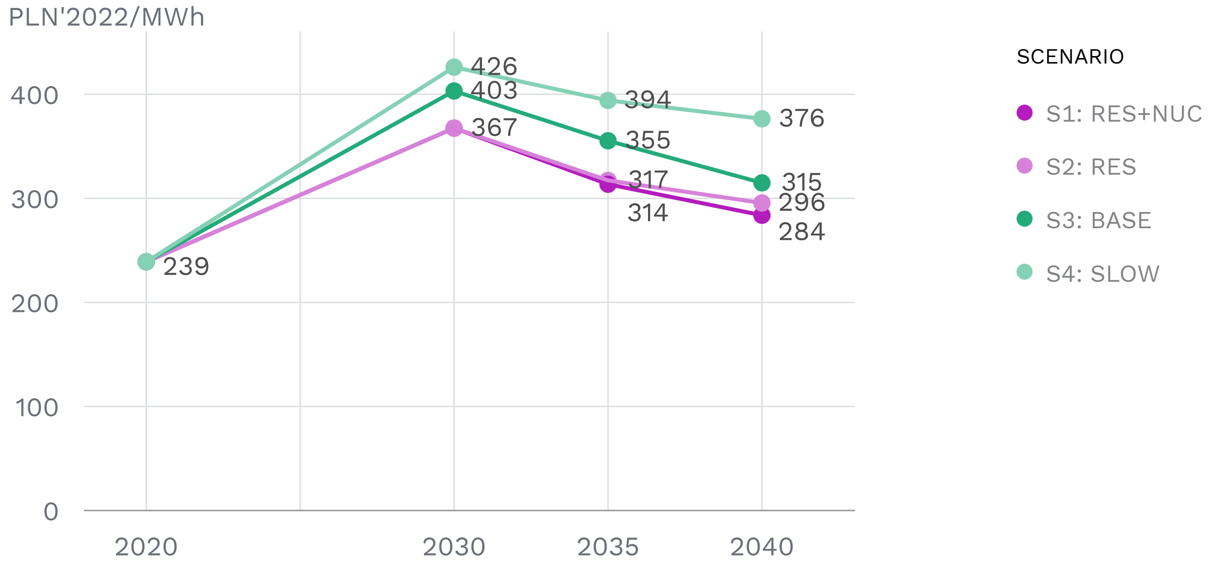
Source: Instrat's own analysis based on the results of the PyPSA-PL model. The cost components included are annuitised CAPEX, annual fixed and variable OPEX costs, including CO_2 emissions. Electricity transmission and distribution costs are not included. Costs related to light vehicle mobility are also present in the PyPSA-PL model. We do not show them here because this sector is not strictly an energy sector. The costs of the construction and operation of CHP plants are included entirely in the 'electricity' category.

Among system costs, electricity costs dominate – this sector is becoming increasingly important as the energy transition progresses. This is happening as a result of widespread electrification. To get a complete picture of the energy system, however, it is necessary to include other sectors in the economic calculation as well, which is exactly what we do in the PyPSA-PL model. It then turns out, for example, that despite the large volume of clean hydrogen production from electrolysis, it is not cost-effective to use it on a large scale to balance the electricity system. Clean hydrogen, in a more cost-efficient manner, displaces grey hydrogen produced from natural gas in industry rather than electricity produced from gas.

The average cost of producing one megawatt-hour of electricity is also an important indicator differentiating the scenarios (Figure 21). Here, the disparity is even more pronounced than in the total system cost. The average unit cost of electricity production already in 2030 in scenarios S1 and S2 (367 PLN/MWh) may be 9% lower than in the baseline scenario S3. In 2040, the difference between the unit costs of scenarios S1 and S3 remains at a similar level, while the difference with respect to scenario S4 increases. In 2040, a megawatt-hour of electricity in scenario S1 is as much as 25% cheaper relative to the scenario S4. This indicates a long-term return on investment in infrastructure with relatively high CAPEX but low OPEX variable costs, such as solar and wind power plants, as well as nuclear. A breakdown of the unit cost components is shown in Figure 22, and a full decomposition by technology can be found in Appendix C.

FIGURE 21. Average unit cost of electricity production (PLN'2022/MWh)

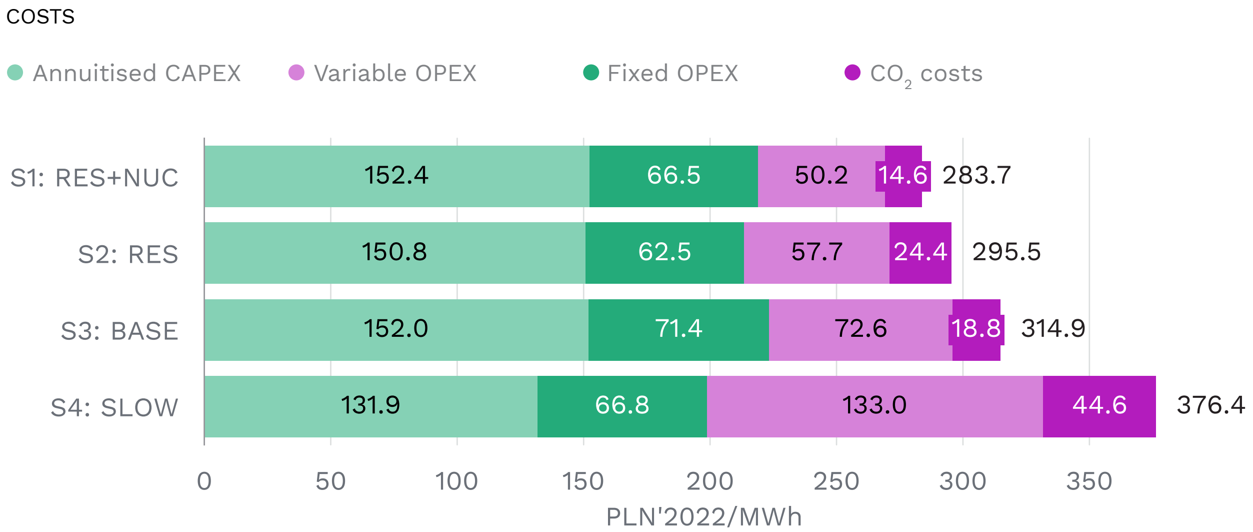
The investment required for the energy transition will increase the average cost of electricity production relative to 2020. However, this cost will decrease over time.



Source: Instrat's own analysis. 2020 – average historical data for 2019-2021 based on ARE. 2030-2040 – based on PyPSA-PL model results. Only investments commissioned between 2026 and 2040 are included in the calculation of the CAPEX component.

FIGURE 22. Average unit cost of electricity production in 2040 by cost component (PLN'2022/MWh)

Ambitious RES deployment means savings not only on the total system cost but also the unit cost of electricity production. Investments in RES pay for themselves through lower fuel purchase costs and CO_2-related costs.



Source: Instrat's own analysis based on the results of the PyPSA-PL model. Costs associated with electricity transmission and distribution were not included. The cost of CO_2 emissions was separated from the variable cost of OPEX. The useful electricity volume was defined as the final electricity use and the sectoral demands related to heat and hydrogen production, minus the energy consumed to produce the hydrogen burned in the power plants. Only infrastructure directly related to electricity generation and storage was included in the cost calculation.

5. How do sectors change? Takeaways for the Polish energy transition strategy

In this section, we present selected findings for each of the modelled sectors, supplemented by comparisons between scenarios or more detailed modelling results.

5.1. Electricity

It is not renewables but natural gas that will be coal's greatest competitor in the next few years. Assuming the rapid RES deployment (scenarios S1 and S2), the only chance to keep coal-fired power plants in the system in an economically justifiable manner is to use them as backup electricity sources, activated on exceptionally cold days with high electricity demand. This would avoid overly significant investments in new gas infrastructure. In the event of a slowdown in RES development (scenarios S3 and S4), the large scale of the necessary gas infrastructure means that backup coal units are no longer needed.

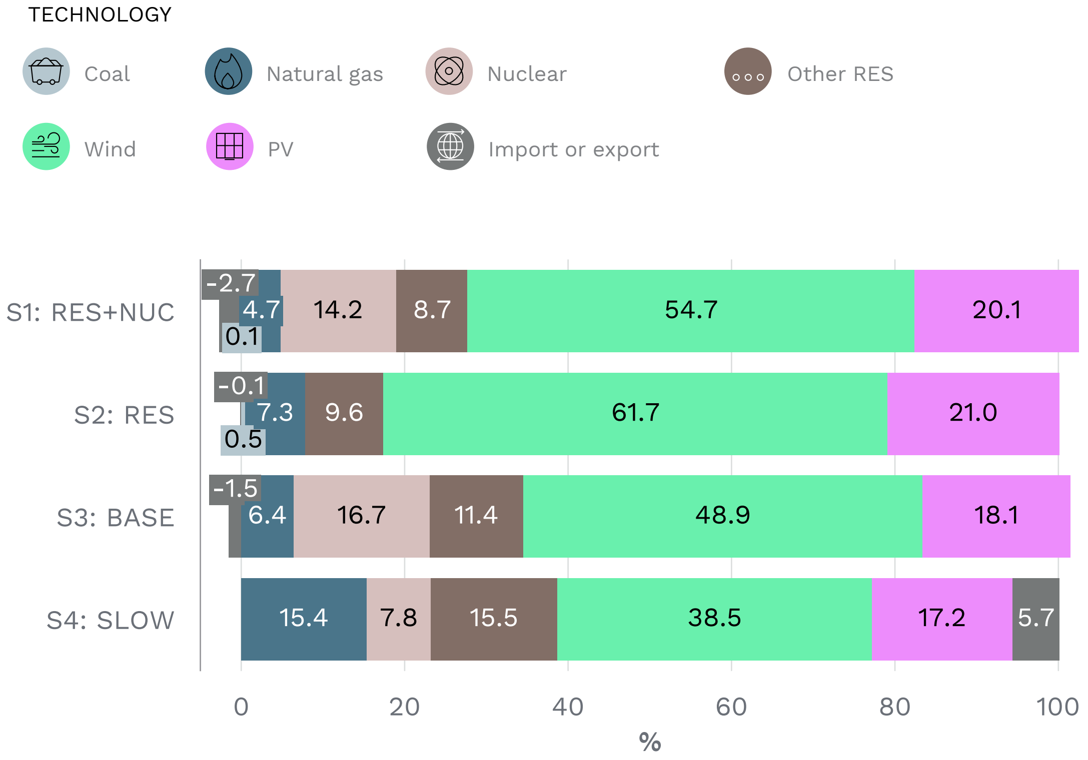
Our model indicates that nuclear power plants could enter the installed capacity mix in a cost-optimal manner, although this involves large investments over the next several years. On the other hand, the benefits of these investments extend over many decades beyond 2040.

Our assumption of a two-year delay in the possible commissioning of nuclear units (which is a rather ambitious assumption anyway) implies that in 2040 nuclear power could meet only about 14% of domestic electricity demand (Figure 23). This means that nuclear plans should not slow down RES development. Nuclear will complement RES, not the other way around (at least in the 2040 perspective).

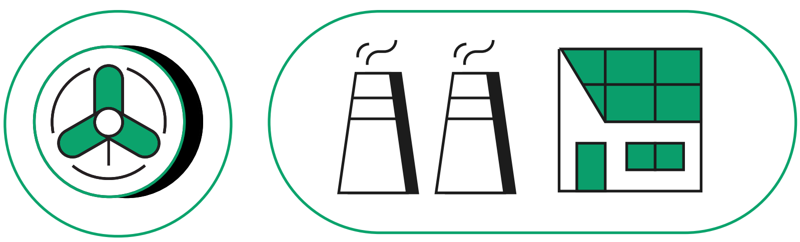
Moreover, the ambitious scenario without nuclear power (S2) is characterised by only a slightly higher level of RES capacity than the ambitious scenario with nuclear power (S1). This shows that **with adequate development of dispatchable capacity (batteries and OCGT hydrogen plants), the lack of a nuclear programme in Poland does not pose a blackout threat**.

In addition, the ambitious non-nuclear scenario (S2) performs similarly to the nuclear scenario S1 in terms of electricity generation costs (the difference is mainly due to profits from nuclear electricity exports), heat pump deployment, and green hydrogen production (Section 5.4). This scenario is associated with slightly higher CO_2 emissions due to the necessity of higher utilisation of dispatchable natural gas power plants.

FIGURE 23. Share of generation technologies and trade in satisfying domestic electricity demand in 2040 (%)



Source: Instrat's own analysis based on the results of the PyPSA-PL optimisation model. The presence of trade means that the total share of generation technologies in satisfying domestic demand can exceed 100%.



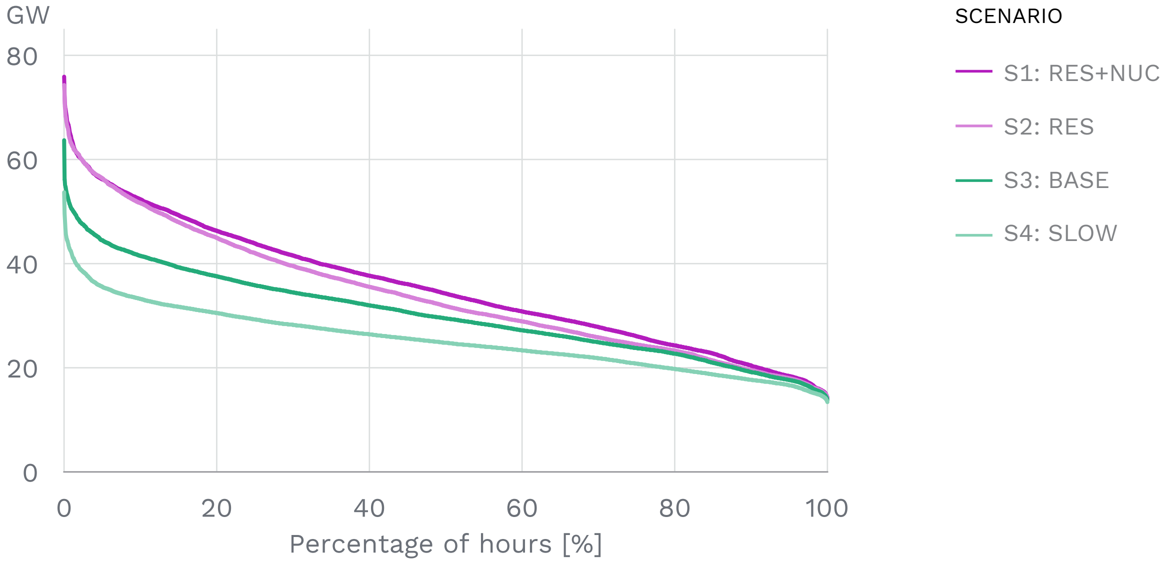
The ambitious RES deployment scenarios (S1, S2) indicate that the maximum instantaneous load on the electricity system could reach as much as 80 GW in 2040 (Figure 24). This happens when the availability of clean wind and solar energy is at its highest, which causes electricity storage units, electrolysers, and resistive heaters in district heating to operate at full capacity (Figure 26). Hence, the load of 80 GW will not necessarily be entirely visible in the national power system. Much of the power from weather-dependent RES can be consumed locally; this can be accomplished by locating electrolysers or batteries close to the RES installations. An optimisation model that considers the cost of grid infrastructure development (which PyPSA-PL does not currently do) would probably also indicate a lower optimal level of maximum electric load. Nevertheless, the fact that the current maximum load in the Polish power system is only about 28 GW (PSE, 2023a) means that the ambitious RES deployment targets presented in scenarios S1 and S2 are undoubtedly a major challenge for transmission and distribution system operators.

Power-to-heat technologies (heat pumps and resistive heaters) are essential contributors to peak power demand. The peak demand they generate can reach as much as 30 GW in scenarios S1 and S2 and exceeds 15 GW in each scenario (Figure 25). This peak power demand occurs when heat demand and weather-dependent RES production are relatively high. This is an efficient way to convert abundantly available electricity into heat, which can then be stored in anticipation of the coldest hours.

The most difficult moments for the system are those of low wind and solar energy generation and high non-shiftable-in-time demand. These are moments of so-called high residual power demand. It turns out that the maximum residual demand in the S1 scenario is about 50 GW, a large part of which, as much as 16 GW, comes from decentralised heat pumps and peak resistive heaters installed in buildings (Figure 26). The system copes with this demand by using a mix of dispatchable power plants burning different fuels (including hydrogen, mainly natural gas). It also discharges electricity storage (including electric car batteries as part of the V2G service) and activates the DSR service to reduce final electricity use. Electricity imports play a marginal role.

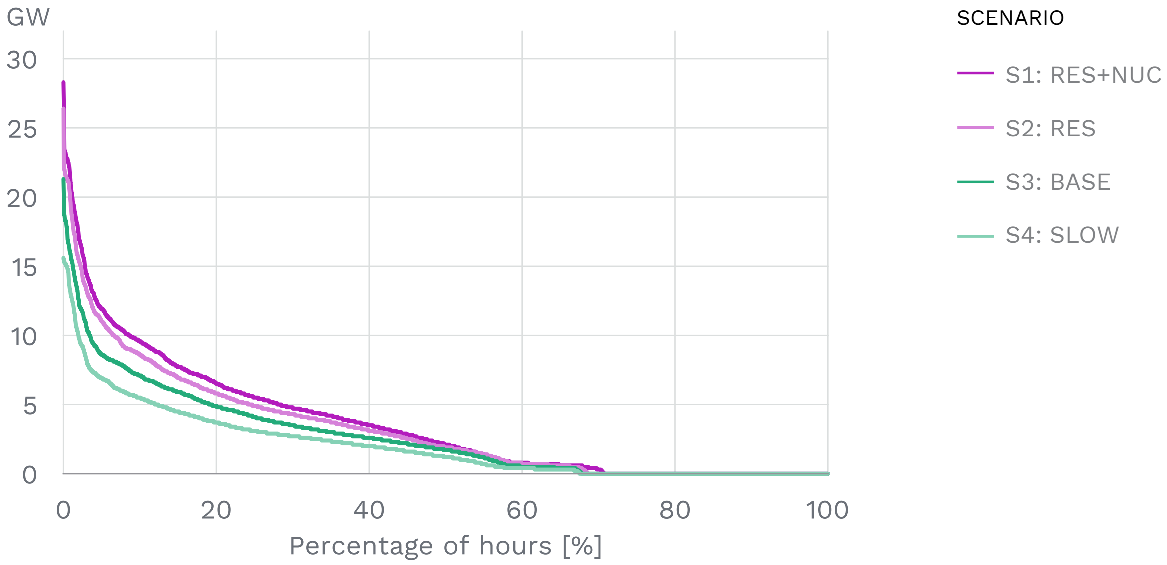
However, our model indicates that the simultaneous development of heat pumps and the buildout of large hydrogen OCGT peaking capacity (with a utilisation rate of 1%) in scenarios S1 and S2 make economic sense. This indicates the need to properly design future public support schemes to replace the current capacity market.

FIGURE 24. Cumulative distribution of total hourly electrical power demand in 2040 (GW)



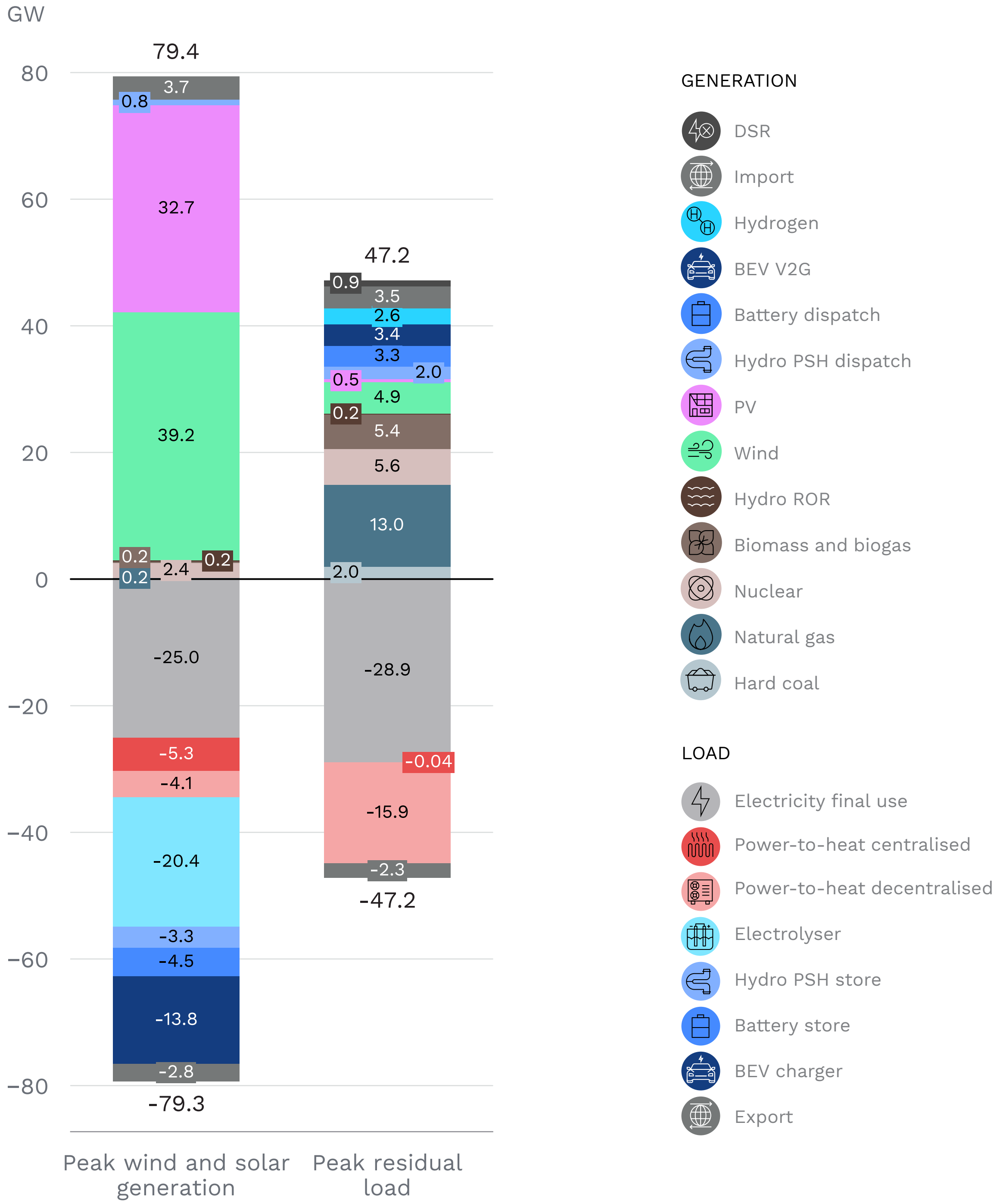
Source: Instrat's own analysis based on the results of the PyPSA-PL optimisation model. The total power demand shown in the graph takes into account: electricity final use, power-to-heat technologies, electric car charging, and electrolysis.

FIGURE 25. Cumulative distribution of hourly electrical power demand for heat generation (power-to-heat) in 2040 (GW)



Source: Instrat's own analysis based on the results of the PyPSA-PL optimisation model. Power-to-heat includes heat pumps and resistive heaters.

FIGURE 26. Structure of electrical power generation and load in 2040 at hours of highest wind and solar generation and highest residual demand (GW) – ambitious RES and nuclear deployment scenario (S1)



Source: Instrat's own analysis based on the results of the PyPSA-PL optimisation model. The values shown are the average power levels in the 40 peak hours of residual demand (i.e. total demand minus generation from wind and solar) and in the 40 peak hours of generation from wind and solar.

5.2. District and decentralised heating

Heat pumps in buildings have great potential for reducing emissions from decentralised heating. However, the increase in their capacity is limited by peak power availability in the electricity system (section 5.1). Residential heat pumps also compete (and win) with systemic heat pumps for this power. While residential heat pumps displace less efficient fossil fuel boilers, systemic heat pumps in our scenarios do not displace CHP plants supporting the electricity system. Our results suggest that using CHP in district heating systems may still be more cost-efficient than the large-scale uptake of systemic heat pumps for many years to come.

While systemic heat pumps play a minor role in our scenarios, the buildout of resistive heaters supplying district heating networks is optimal in each scenario. Due to the low investment costs of this technology, it constitutes a cost-effective method of using surplus wind and solar power.

Notably, a prerequisite for the effective use of CHP to meet both heat and electricity demand is to make CHP operations more flexible by deploying long-term heat storage facilities (Table 1), which are much cheaper than electricity storage per unit of energy stored. Heat storage is also necessary to store the heat generated by resistive heaters. Heat stored during warmer weeks can then be used for heating during exceptionally cold weeks, as in the example of a heat generation profile in district heating presented in Figure 27A.

TABLE 1. Heat storage capacity (GWh)

Storage type	Scenario	2030	2035	2040
Heat storage in district heating	S1: RES+NUC	50	300	550
	S2: RES	50	300	550
	S3: BASE	25	150	275
	S4: SLOW	5	30	55
Heat storage combined with heat pumps and resistive peak heaters in decentralised heating	S1: RES+NUC	10	65	95
	S2: RES	10	60	100
	S3: BASE	9	40	73
	S4: SLOW	7	25	53

Source: Instrat's own analysis based on PyPSA-PL results.

Concerning small heat pumps and peak resistive heaters in decentralised heating, the key is to use small-scale heat storage units (Table 1) to reduce peak power demand, which brings tangible system benefits. We present an example of a heat generation profile in a decentralised system based on these technologies in Figure 27B; in that figure, one notices hours when heat storage helps cover the peak heat demand, significantly reducing the electrical power demand.

Due to the treatment of all district heating systems in Poland in an aggregate manner (as a so-called copper plate), our assumptions on the high use of CHP in district heating networks may be too optimistic.

Our results indicate the potential cost-effectiveness of using CHP in district heating systems. However, when planning the energy transition, each system should be approached individually, looking, for example, for the opportunities to efficiently use waste heat from local industrial plants or data centres. In such cases, the coefficient of performance (COP) of systemic heat pumps drawing heat from these sources may be much higher than that resulting from our conservative assumption of using 50% ambient air and 50% wastewater as heat sources for systemic heat pumps.

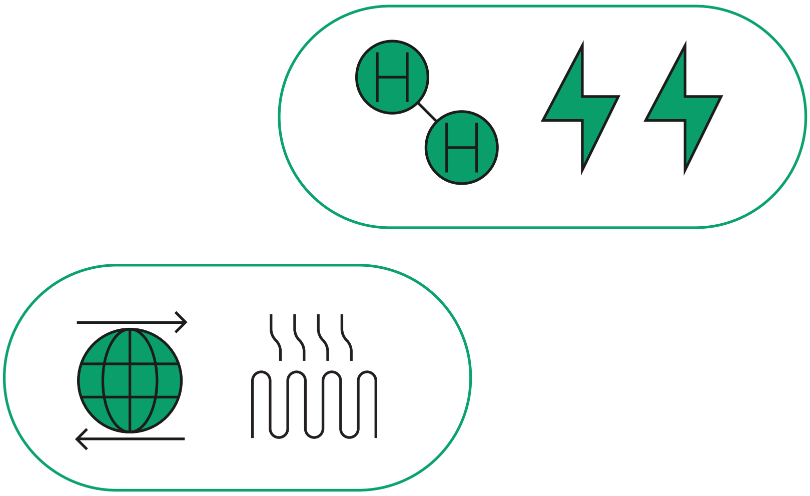
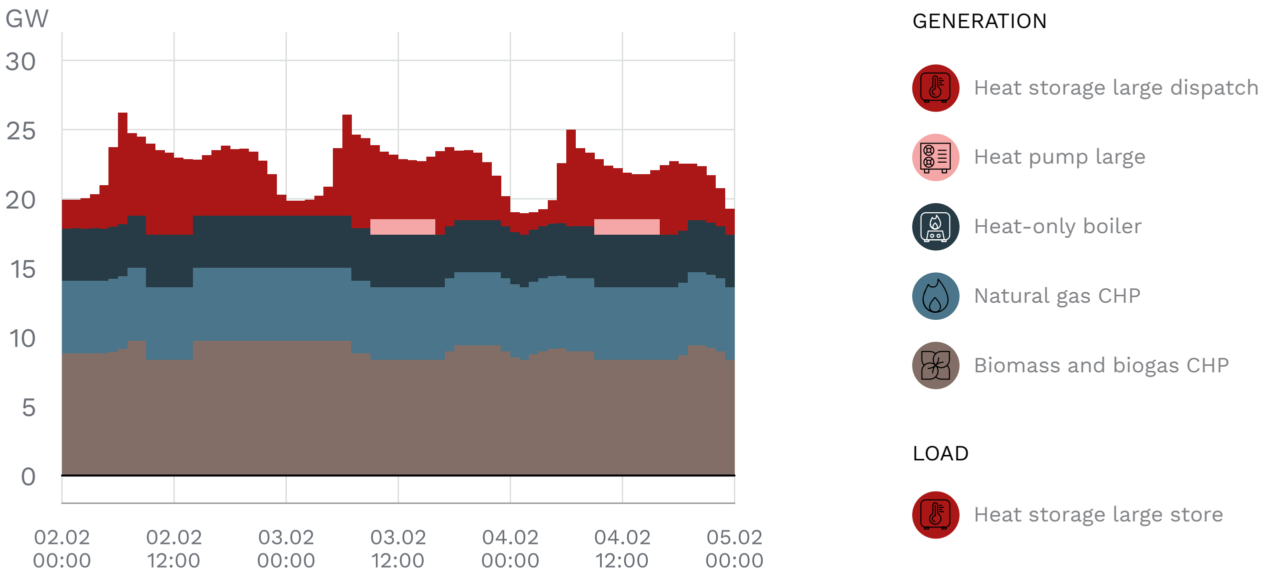


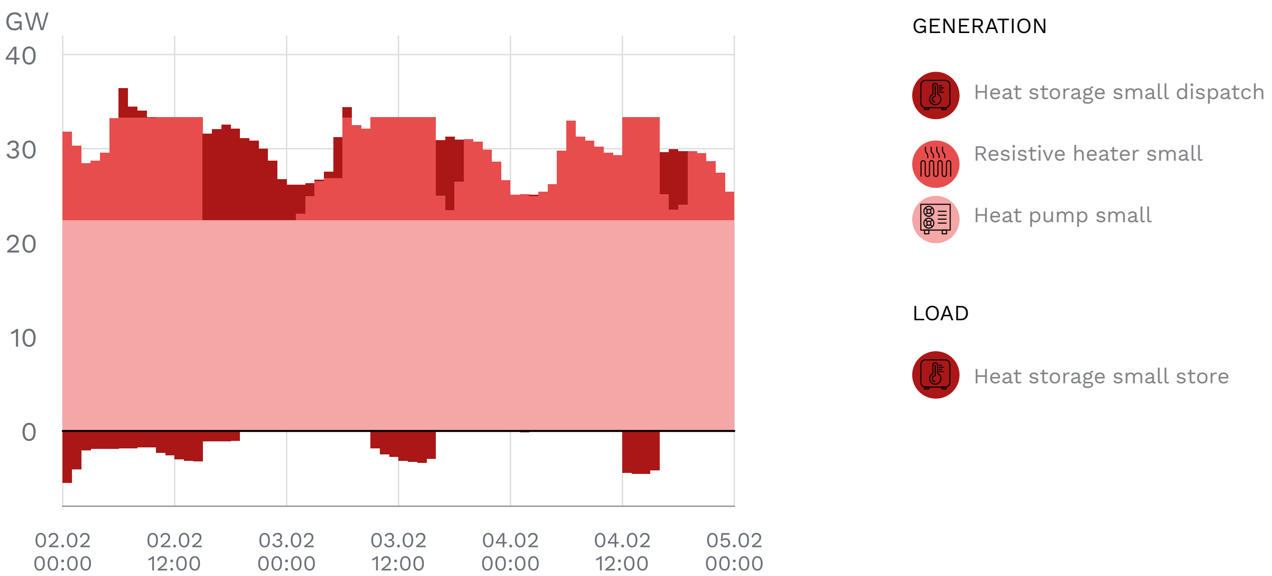
FIGURE 27. Example of heat generation profile in winter 2040 (GW) – ambitious RES and nuclear deployment scenario (S1)

With the optimised use of heat storage, the peak thermal power demand of the generating sources can be reduced. In the case of heat pump-based heating, this means less peak demand for electrical power.

A. DISTRICT HEATING



B. BUILDINGS WITH DECENTRALISED HEAT PUMPS, PEAK RESISTIVE HEATERS, AND HEAT STORAGE



Source: Instrat's own analysis based on the results of the PyPSA-PL optimisation model. There is no charging of heat storage in district heating in the period shown (Figure 27A).

5.3. Electromobility of light vehicles

For the light vehicle mobility sector, we only optimise the annual operating costs of the vehicles, i.e. maintenance and fuel costs. The high price of petroleum-based fuels[13] causes the PyPSA-PL model to indicate the maximum assumed potential of electric vehicles as optimal. We do not include the CAPEX cost, as we do not expect significant differences in the price of electric and ICE vehicles in the 2030-2040 timeframe, and the choice of vehicle model is often dictated by criteria other than energy efficiency.

A fleet of battery electric vehicles is both a consumer and a supplier of (stored) electricity in the model. It has a very high potential for electricity storage – for a fleet of 4.7 million BEVs in 2040 in scenarios S1 and S2, this is about 155 GWh (equal to about 39 GW of four-hour dedicated battery energy storage). When used optimally, the V2G service – i.e. supporting the electricity system by BEVs at times of high demand – could significantly contribute to covering the system's short-term electricity storage needs.

For example, in the S1 scenario in 2040, BEVs absorb 13.3 TWh and return 1.5 TWh of electricity to the system. This means that the net demand from BEVs is 11.8 TWh in this scenario (shown in Figure 1C), and the ratio of energy absorbed for V2G to energy absorbed for driving is only about 13%.

However, it is unknown to what extent BEV owners will be willing to participate in the V2G service when given the opportunity. It is also difficult to answer today whether the price incentives will be strong enough to make charging and discharging profiles of such vehicles as flexible as those derived from our optimisation model (e.g. Figures 3 and 4).

It is worth noting that the assumptions for V2G strongly influence the resulting optimal level of dispatchable capacity in the power system (which also has implications for the optimal installed heat pump capacity – see sections 5.1 and 5.2). We have conservatively assumed that only 25% of the chargers will be bidirectional (i.e. able to facilitate the V2G service) – for scenarios S1 and S2, this means approximately 12.9 GW of electrical capacity supporting the power system. Considering that storing electricity for the power system is not the primary purpose of BEVs, we also impose the condition of an adequate charge level for EV batteries at 7 am – we assume that it cannot be less than 75%. This limits the possibility of using electric vehicles as long-term electricity storage. We represent the accelerated degradation of EV batteries as an additional V2G cost of PLN 50/MWh.

We believe that how electric cars will be used and the future availability of charging infrastructure (including V2G) are among the main uncertain assumptions of our energy system model. Adjusting these assumptions could result in both an increase (in the case of less flexible charging and discharging profiles) or a decrease (in the case of broader availability of V2G infrastructure) in system costs in the sectors analysed.

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13 We take into account the cost of CO_2 emissions and, in an estimated way, the cost of petroleum refining.

5.4. Hydrogen production

From 2035 onwards, our model indicates the optimal level of electrolyser capacity based on system cost optimisation, ensuring that surplus electrical power is used efficiently. The installed electrical capacity of electrolysers in 2040 (Figure 28A) is:

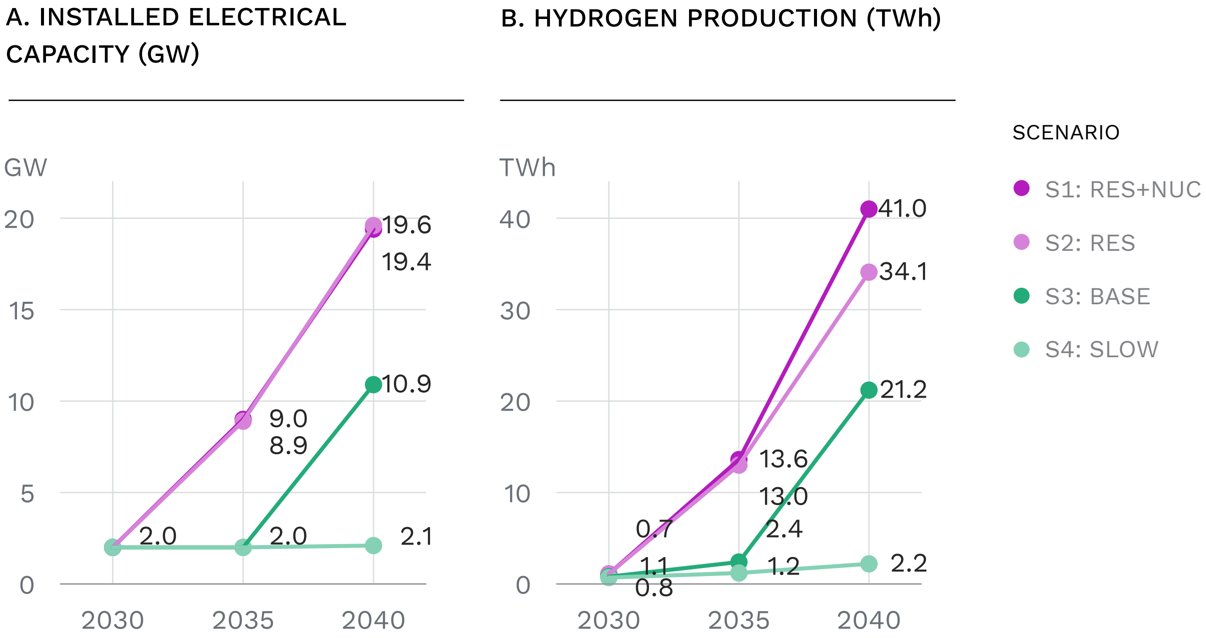
- in scenarios S1 and S2 – approximately 20 GW,
- in scenario S3 – approximately 11 GW,
- in scenario S4 – only about 2 GW.

In none of the scenarios does the simulated level of green hydrogen production fully meet the total assumed hydrogen demand. Thus, in 2040, part of the demand is further met by grey hydrogen production from steam methane reforming (the model does not incorporate hydrogen imports, although they are quite a realistic possibility). **This indicates that the risk of building too much power generation capacity in the electricity sector should not be an argument against the simultaneous ambitious deployment of RES and nuclear power**, as electrolysis is a cost-effective way of using any excess capacity. However, the limited deployment of offshore wind farms in the S1 (RES+NUC) scenario casts doubt on the viability of developing additional offshore wind farms solely for hydrogen production (see Figure 28).

The production potential for green hydrogen from electrolysis in 2040, in the ambitious RES and nuclear deployment scenario (S1), amounts to **around 41 TWh** (1.2 million tonnes). In the ambitious scenario without nuclear power (S2), it is **around 34 TWh** (1 million tonnes). These values are equal to or slightly higher than the amount of grey hydrogen currently produced in Poland (around 1 million tonnes per year). In the baseline scenario (S3), the potential for green hydrogen production in 2040 is about 21 TWh (0.6 million tonnes), and in the slow transition scenario (S4), it is just over 2 TWh. In the latter, the (green) hydrogen economy is virtually non-existent (Figure 28B).

Even in the ambitious S1 and S2 scenarios, the economically viable production of green hydrogen in 2030 (assuming 2 GWe of electrolysers are commissioned due to subsidies) is less than 1 TWh. **The hydrogen economy is not likely to develop significantly until around 2035 (scenarios S1 and S2) or 2040 (baseline scenario S3).** It is possible that, as a result of public support for green hydrogen production, the sector will develop somewhat earlier. This is not optimal from the point of view of short-term emission reductions. However, it may be a necessary condition to prepare the Polish economy for a hydrogen ‘revolution’ in the late 2030s.

FIGURE 28. Installed capacity of electrolysers and electrolysis-based hydrogen production



Source: Instrat's own analysis based on the results of the PyPSA-PL optimisation model.

Electrolysis-based hydrogen production will be seasonal (due to the high availability of solar energy and low heating demand during the summer months), and the assumed final use demand for this energy carrier is constant. The capacity required in 2040 to store hydrogen in scenarios S1 and S2 (assuming the total hydrogen supply is balanced by grey hydrogen produced at existing facilities) is approximately 1-1.5 TWh (Table 2). The currently existing natural gas storage facilities would allow (after appropriate adjustment) for storing much higher volumes of hydrogen. For this reason, the size and number of these underground storage facilities are not a constraint on developing the Polish hydrogen economy.

TABLE 2. Long-term hydrogen storage capacity (GWh)

Scenario	2030	2035	2040
S1: RES+NUC	0	80	1 150
S2: RES	0	70	1 530
S3: BASE	0	0	240
S4: SLOW	0	0	0

Source: Instrat's own analysis based on PyPSA-PL results. Capacity is provided in units of hydrogen's lower calorific value.

Explanations and abbreviations

ARE	Energy Market Agency (*Agencja Rynku Energii*)
BEV	Battery electric vehicle
CAPEX	Capital expenditure (i.e. investment costs)
CHP	Combined heat and power generation
CO_2	Carbon dioxide
DSO	Distribution system operator
DSR	Remunerated reduction of electricity consumption by end users at the request of the transmission system operator (Demand Side Response)
ENTSO-E	European Network of Transmission System Operators for Electricity
ETS	Emissions Trading System
GDDKiA	General Directorate for National Roads and Highways (*Generalna Dyrekcja Dróg Krajowych i Autostrad*)
GUS	Statistics Poland (*Główny Urząd Statystyczny*)
ICE	Internal combustion engine
IMGW	Institute of Meteorology and Water Management (*Instytut Meteorologii i Gospodarki Wodnej*)
KOBiZE	National Centre for Emissions Management (*Krajowy Ośrodek Bilansowania i Zarządzania Emisjami)*
KPEiK	National Energy and Climate Plan for 2021-2030 (*Krajowy plan na rzecz energii i klimatu na lata 2021-2030*)
MKiŚ	Ministry of Climate and Environment (*Ministerstwo Klimatu i Środowiska*)
NECP	National Energy and Climate Plan
OCGT	Open cycle gas turbine
OPEX	Operating costs
PEP2040	Energy Policy of Poland until 2040 (*Polityka energetyczna Polski do 2040 r.*)
PLN'2022	Polish zloty – real 2022 value
Power-to-heat	Technologies enabling the generation of useful heat due to electricity consumption, e.g. heat pumps and resisitive heaters
PSE	Polish TSO (*Polskie Sieci Elektroenergetyczne*)
PSH	Pumped storage hydropower
PV	Photovoltaics
PyPSA-PL	Optimisation model of the Polish energy system created by Instrat Foundation based on the PyPSA framework (Python for Power System Analysis)
RES	Renewable energy sources
SNSP	System Non-Synchronous Penetration
TSO	Transmission system operator (in Poland: *Polskie Sieci Elektroenergetyczne* – PSE)
URE	Energy Regulatory Office (*Urząd Regulacji Energetyki*)
V2G	Bidirectional vehicle-to-grid electricity transmission service

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Appendix A – detailed scenario assumptions

TABELA A.1. Demand and consumption assumptions for energy carriers in the scenarios considered

Demand /consumption	Scenario	Unit	2020*	2025	2030	2035	2040
Electricity (1)	RES+NUC and RES (S1, S2)	TWh	159.4	168.3	177.2	190.3	202.0
	BASE (S3)		168.3	168.3	177.2	187.4	196.9
	SLOW (S4)		177.2	168.3	177.2	184.1	190.9
Heat for space heating (2)	RES+NUC and RES (S1, S2)	TWh	190.3	177.8	174.1	144.6	120.6
	BASE (S3)		202.0	177.8	174.1	155.2	138.5
	SLOW (S4)		159.4	177.8	174.1	170.3	166.6
Heat for water heating (2)	RES+NUC and RES (S1, S2)	TWh	168.3	46.6	47.7	48.3	49.0
	BASE (S3)		177.2	46.6	47.7	48.3	49.0
	SLOW (S4)		187.4	46.6	47.7	48.3	49.0
Hydrogen (3)	RES+NUC and RES (S1, S2)	TWh**	196.9	35.5	36.4	45.3	53.0
	BASE (S3)		159.4	35.5	36.4	39.9	43.2
	SLOW (S4)		168.3	35.5	36.4	38.4	40.5
Light vehicle mobility (4)	RES+NUC and RES (S1, S2)	bln vkm***	177.2	226.2	237.8	226.1	194.2
	BASE (S3)		184.1	226.2	237.8	237.8	237.8
	SLOW (S4)		190.9	226.2	237.8	243.8	250.0
Other energy use of fossil fuels and associated CO_2 emissions (5)	RES+NUC and RES (S1, S2)	TWh**	181.7	251.4	252.2	221.1	194.2
		mln t CO_2	177.8	66.7	66.9	58.8	51.7
	BASE (S3)	TWh**	174.1	251.4	252.2	237.2	223.6
		mln t CO_2	144.6	66.7	66.9	63.0	59.4
	SLOW (S4)	TWh**	120.6	251.4	252.2	246.3	240.9
		mln t CO_2	181.7	66.7	66.9	65.4	64.0

Source: Instrat's own analysis based on data from Eurostat, GUS, KOBiZE, and own assumptions.

(1) Does not take into account demand from power-to-heat technologies, light electric vehicles (BEVs), own needs of power plants. Takes into account network losses.

(2) Takes into account centralised and decentralised heat. Does not take distribution losses into account. Our estimated share of district heating in meeting the total heating needs for 2019-2021 is approximately 32%.

(3) It takes into account direct final use and use as a substrate for other products, such as ammonia.

(4) Includes passenger cars and light-duty vehicles (LDVs).

(5) Not directly represented in the PyPSA-PL model.

* The value for 2020 shown in the table is the average of the 2019-2021 data.

** Given as lower calorific value.

*** For the purposes of our analysis, we assume that 0.210 kWh of electricity (with an electric drive efficiency of 85%) or 0.713 kWh of the lower calorific value of petroleum fuel (with an internal combustion drive efficiency of 25%) is required per vehicle-kilometre.

TABLE A.2. Assumptions for the installed capacity (or its maximum additions) of generation and storage technologies in the scenarios considered

Technology	Scenario	Unit	2026–2030	2031–2035	2036–2040
PV – ground	RES+NUC and RES (S1, S2)	GWe	max. +1 annually		
	BASE (S3)		max. 11.4	max. 14.4	maks. 17.4
	SLOW (S4)		max. 10.4	max. +0.5 annually	
PV – roof	RES+NUC and RES (S1, S2)	GWe	max. +2 annually		
	BASE (S3)		max. 15.6	max. 21.6	maks. 27.6
	SLOW (S4)		max. 14.6	max. +1 annually	
Wind – onshore	RES+NUC and RES (S1, S2)	GWe	max. 20.6	max. +2 annually	
	BASE (S3)		max. 14	max. 17	max. 20
	SLOW (S4)		max. 12	max. +0.75 annually	
Wind – offshore	RES+NUC and RES (S1, S2)	GWe	max. 5.9	max. +1.5 annually	
	BASE (S3)		max. 5.9	max. +1.2 annually	
	SLOW (S4)		max. 3.2	max. +0.9 annually	
Agricultural biomass-fired CHP plants (1)	RES+NUC and RES (S1, S2)	GWe	1	no limit	
	BASE (S3)				
	SLOW (S4)				
Biogas plants (1)	RES+NUC and RES (S1, S2)	GWt*	1.5	no limit	
	BASE (S3)				
	SLOW (S4)				
Biogas storage at biogas plants (1)	RES+NUC and RES (S1, S2)	GWht**	0	no limit	
	BASE (S3)				
	SLOW (S4)				
Biogas-fired CHP engines (1)	RES+NUC and RES (S1, S2)	GWe	0.65	no limit	
	BASE (S3)				
	SLOW (S4)				
Run-of-river hydroelectric	RES+NUC and RES (S1, S2)	GWe	0.61	0.61	0.61
	BASE (S3)				
	SLOW (S4)				
Large nuclear power plants (1)	RES+NUC (S1)	GWe	0	max. 1.1	max. 4.7
	RES (S2)		0	0	0
	BASE (S3)		0	max. 1.1	max. 4.7
	SLOW (S4)		0	0	max. 2.2
Small nuclear power plants (1)	RES+NUC (S1)	GWe	0	0	max. 0.9
	RES (S2)		0	0	0
	BASE (S3)		0	0	max. 0.9
	SLOW (S4)		0	0	0
Coal-fired power and CHP plants (including industrial) (1)	RES+NUC and RES (S1, S2)	GWe	20.4	early decommissioning allowed**	
	BASE (S3)				
	SLOW (S4)				
Natural gas-fired power and CHP plants (including industrial)	RES+NUC and RES (S1, S2)		no limit	no new investment	
	BASE (S3)		no limit	no new investment	
	SLOW (S4)		max. +1.5 annually		no new investment

Technology	Scenario	Unit	2026–2030	2031–2035	2036–2040
Hydrogen-fired power and CHP plants (1)	RES+NUC and RES (S1, S2)	GWe	0	no limit	
	BASE (S3)				
	SLOW (S4)				
Pumped storage hydropower plants (3)	RES+NUC and RES (S1, S2)	GWe	2.63	4.37	4.37
	BASE (S3)				
	SLOW (S4)				
Large batteries (3, 5)	RES+NUC and RES (S1, S2)	GWe	1	2	5
	BASE (S3)				
	SLOW (S4)				
Small batteries (3, 5)	RES+NUC and RES (S1, S2)	GWe	0.73	1.23	1.73
	BASE (S3)				
	SLOW (S4)				
DSR (3, 6)	RES+NUC and RES (S1, S2)	GWe	2.02	2.17	2.31
	BASE (S3)		2.02	2.14	2.25
	SLOW (S4)		2.02	2.10	2.18
Heat pumps – buildings (7)	RES+NUC and RES (S1, S2)	GWt***	max. 10	no limit	
	BASE (S3)				
	SLOW (S4)				
Heat pumps – district heating	RES+NUC and RES (S1, S2)	GWt***	max. 1	no limit	
	BASE (S3)				
	SLOW (S4)				
Heat storage – district heating	RES+NUC and RES (S1, S2)	GWht****	max. 50	max. +50 annually	
	BASE (S3)		max. 25	max. +25 annually	
	SLOW (S4)		max. 5	max. +5 annually	
Electrolysers (1)	RES+NUC and RES (S1, S2)	GWe (electrical capacity)	2	no limit	
	BASE (S3)				
	SLOW (S4)				
BASE (S3)	RES+NUC and RES (S1, S2)	mln vehicles	max. 1.3	max. 2.8	max. 4.7
	SLOW (S4)		max. 1.3	max. 2.5	max. 3.9
	OT (S4)		max. 1.3	max. 2.3	max. 3.3

Source: Instrat's own analysis based on own assumptions and (MKiŚ, 2023).

(1) Installed capacity up to 2030 is not subject to optimisation.

(2) Based on optimising annual operating costs (including fixed maintanence cost).

(3) Installed capacity is not subject to optimisation in any year range.

(4) We assume that the average annual mileage of the vehicle fleet is 9 700 km per vehicle and the maximum average hourly speed of the fleet is 55 km/h.

(5) Large batteries have a capacity-to-power ratio of 4h, while small batteries have a capacity-to-power ratio of 2h.

(6) Demand Side Response; remunerated reduction of electricity consumption by end users at the request of the transmission system operator.

(7) The values given are the peak heat pump output (without peak resistive heater) independent of temperature. Assuming that a typical '8 kW' heat pump has a peak output of 4 kWt, 10 GWt of thermal output corresponds to 2.5 million heat pumps.

* Lower calorific value of biogas per unit time.

** Lower calorific value of biogas.

*** Thermal power.

**** Thermal energy.

TABLE A.3. Assumptions on the achievable share of non-synchronous sources in the instantaneous electricity generation mix (maximum SNSP)

Parameter	Scenario	Unit	2020–2025*	2030	2035	2040
Max. SNSP	RES+NUC and RES (S1, S2)	%	60–65	85	90	95
	BASE (S3)			75	80	85
	SLOW (S4)			65	70	75

Source: Instrat's own analysis based on own assumptions.

* The value shown for 2020-2025 is based on an estimate (Kubiczek, 2023a).

TABLE A.4. Assumptions for energy carrier prices and CO_2 emission prices

Parameter	Scenario	Unit	2020	2025	2030	2035	2040
CO_2 emission allowances (EU ETS)	RES+NUC and RES (S1, S2)	EUR/tCO_2	29.5	102.6	138.6	159.2	179.7
	BASE (S3)						
	SLOW (S4)						
Natural gas	RES+NUC and RES (S1, S2)	PLN/GJ*	14.4	65.1	36.0	34.2	32.4
	BASE (S3)						
	SLOW (S4)						
Hard coal	RES+NUC and RES (S1, S2)	PLN/GJ*	14.3	17.0	11.9	11.5	11.0
	BASE (S3)						
	SLOW (S4)						
Agricultural biomass / biogas substrate (1)	RES+NUC and RES (S1, S2)	PLN/GJ*	32.8	39.1	31.8	31.8	31.8
	biogas substrate (1)						
	SLOW (S4)						

Source: Instrat's own analysis based on energy.instrat.pl, (IEA, 2022), and own assumptions.

(1) For the biogas substrate, we assume the same price per unit calorific value of biogas as for agricultural biomass.

* Price in relation to the lower calorific value of the fuel.

TABLE A.5. Assumptions on the 2025 installed capacity for technologies subject to investment optimisation in the scenarios considered

Technology	Unit	Installed capacity in 2025
PV – ground	GWe	8.9
PV – roof	GWe	13.3
Wind – onshore	GWe	12.7
Natural gas-fired power plants and CHP plants (including industrial)	GWe	6.7
Heat pumps – buildings (1)	GWt	4.5

Source: Instrat's own analysis based on compilation of data from ARE, URE, PSE, PORT PC, and own assumptions.

(1) The values given are the peak heat pump output (without peak resistive heater) independent of temperature.

Appendix B – selected methodological details

B1. Data sources and assumptions influencing the results

In this section of the report, we present selected methodological details (in addition to those presented in Appendix A) to facilitate the interpretation of our results.

COST ASSUMPTIONS

- We express all monetary values in real 2022 prices. We convert between currencies using average annual exchange rates (for 2022: 1 EUR – PLN 4.69, 1 USD – PLN 4.46).
- We convert investment costs into an annuitised CAPEX using a real discount rate of 3%.
- Our assumptions on long-term prices for energy carriers (from 2030 onwards) and ETS emission allowance fees (which also constitute the reference value for emission costs not covered in the ETS today) are based on the Announced Pledges scenario from the World Energy Outlook 2022 (IEA, 2022).
- Assumptions on technologies' characteristics and associated costs are based primarily on data from the Danish Energy Agency (DAE, 2023) and our own compilation of sources. The full data containing these assumptions can be found in the GitHub repository of the PyPSA-PL model (Kubiczek, 2023b).

ELECTRICITY

- The hourly profiles of wind and solar power availability in neighbouring countries (and indirectly also in Poland) are based on the Pan-European Climatic Database (PECD) used for simulations by ENTSO-E (De Felice, 2022). The profiles used in our model for Poland at the voivodeship level are based on the more granular data of the EMHIRES project (Gonzalez-Aparicio et al., 2021), which have been non-linearly scaled to agree with the PECD data at the national scale. Furthermore, we assume that wind turbines built between 2021 and 2030 have a 20% better capacity utilisation on average than those built by 2020.
- Hourly data on RES availability and hourly electricity final use demand (as a percentage of annual demand) are for 2012 (ENTSO-E, 2023a), a typical year for renewable energy availability. It was also a year with a particularly high peak demand for space heating. We present our assumed demand profiles for the different energy carriers for the 2040 simulations in Figure 25.
- We include limits on the long-term installed capacity potential of wind turbines and solar photovoltaics based on (Czyżak et al., 2021), except for prosumer photovoltaics, for which we assume a potential 50% higher (due to the possibility of its installation on

multi-family residential buildings, which the earlier analysis excluded).

- Installed capacity and annual electricity demand in neighbouring countries are based on the National Trends scenario from the TYNDP 2022 Scenario Report (ENTSO-E & ENTSO-G, 2022).

- We assume 70% of cross-border transmission capacity availability relative to historical maximum flows, augmented with planned interconnector investments (ENTSO-E, 2023b). The reported interconnector capacities relate to this reduced availability.

- We assume electricity transmission losses of 5% for power-to-heat technologies, electrolysis, and electric car charging.

- We assume the remuneration cost of DSR, i.e. reduction of electricity consumption by end users at the request of the transmission system operator, at 1 200 PLN/MWh.

- Data on the current state of the Polish electricity system, as well as trends in its changes, is an original compilation by the Instrat Foundation based on data from institutions such as the Energy Market Agency (ARE, 2023), the Polish TSO (PSE, 2023c; 2023b), the Energy Regulatory Office (URE, 2022b), the Polish Power Transmission and Distribution Association (PTPiREE, 2023), and industry knowledge. The data reported by these institutions often diverge from each other, making it difficult to identify the single most reliable source of information and necessitating conducting our own analysis. In the case of conventional units, we base our scenarios for the maximum capacity level of existing (and being under construction) coal and gas-fired units until 2040 on energy.instrat.pl (Charkowska et al., 2022).

HEATING

- We create the heat demand profiles for space heating based on the so-called degree-day method, assuming a threshold temperature of 16°C. Historical ambient air temperature data comes from the Institute of Meteorology and Water Management (IMGW, 2023). Daily hourly heating demand profiles for space heating follow (Neumann et al., 2023), whereby we assume a 50% 'flattening' of these profiles based on empirical data of flatter heating profiles in buildings heated with heat pumps than in those heated with gas boilers (Watson et al., 2021).

- We assume that all small heat pumps are of air-to-water type. We create their efficiency profiles (COP) based on the Carnot process with a correction factor of 0.45, assuming that the water temperature in the heating system ranges between 30°C (for outdoor temperature of 15°C) and 55°C (for outdoor temperature of -20°C). These assumptions imply an average annual COP of approximately 3.5.

- We assume that 50% of systemic heat pumps are of air-to-water type, and the other 50% of water-to-water type using wastewater at 15°C. We model the COP based on the Lorenz process with a correction factor of 0.5, assuming that the output/input water temperature of the district heating network ranges between 40/70°C (for outdoor temperature of 10°C) and 55/90°C (for outdoor temperature of -20°C). These assumptions imply an average annual COP of approximately 2.9.

- We assume that the peak resistive heater cooperating with the small heat pump can generate maximally 2% of the heat generated by the heat pump over the year.

- We assume a district heating distribution loss of 12%.

- We assume the annual maintenance cost of the district heating distribution network is PLN 72 for each megawatt hour of heat delivered.

- We assume that the share of district heating in meeting the total heating demand will remain at our estimated level of 32%. Similarly, we assume that the share of biomass in decentralised heating will also remain at the same level as at present (20% of the total heating demand). We assume no coal in decentralised heating from 2030.

- Data on the current state of Poland's district heating sector is based on a compilation of data from the Energy Market Agency (ARE, 2023), the Energy Regulatory Office (URE, 2022a), as well as publications from Forum Energii (Forum Energii, 2023). Data on the current state of the Polish decentralised heating sector is based on a compilation of data from Statistics Poland (GUS, 2023b), Eurostat (Eurostat, 2023), the Polish Organisation for the Development of Heat Pump Technology (PORT PC, 2023), and own estimates.

LIGHT VEHICLE MOBILITY

- We create the hourly profiles of light vehicle mobility based on data from the General Directorate for National Roads and Highways (GDDKiA, 2023). Following (Neumann et al., 2023), we assume that the charging availability of light electric vehicles is 80% on average and 95% at a maximum and is linked to the mobility value (i.e. during hours of high mobility, charging is less available because vehicles are on the road).

- Data on vehicle-kilometres travelled by light vehicles come from Statistics Poland (GUS, 2023a).

- Scenarios for the electric car fleet growth based on (MKiŚ, 2023; PSPA, 2023).

- We assume an 11 kW charger and a 33 kWh battery for each BEV. Furthermore, we assume that only 25% of the chargers are bidirectional (i.e. enabling V2G service). Following (Neumann et al., 2023), we assume that each day at 7 am, the BEV battery charge level must not be lower than 75%

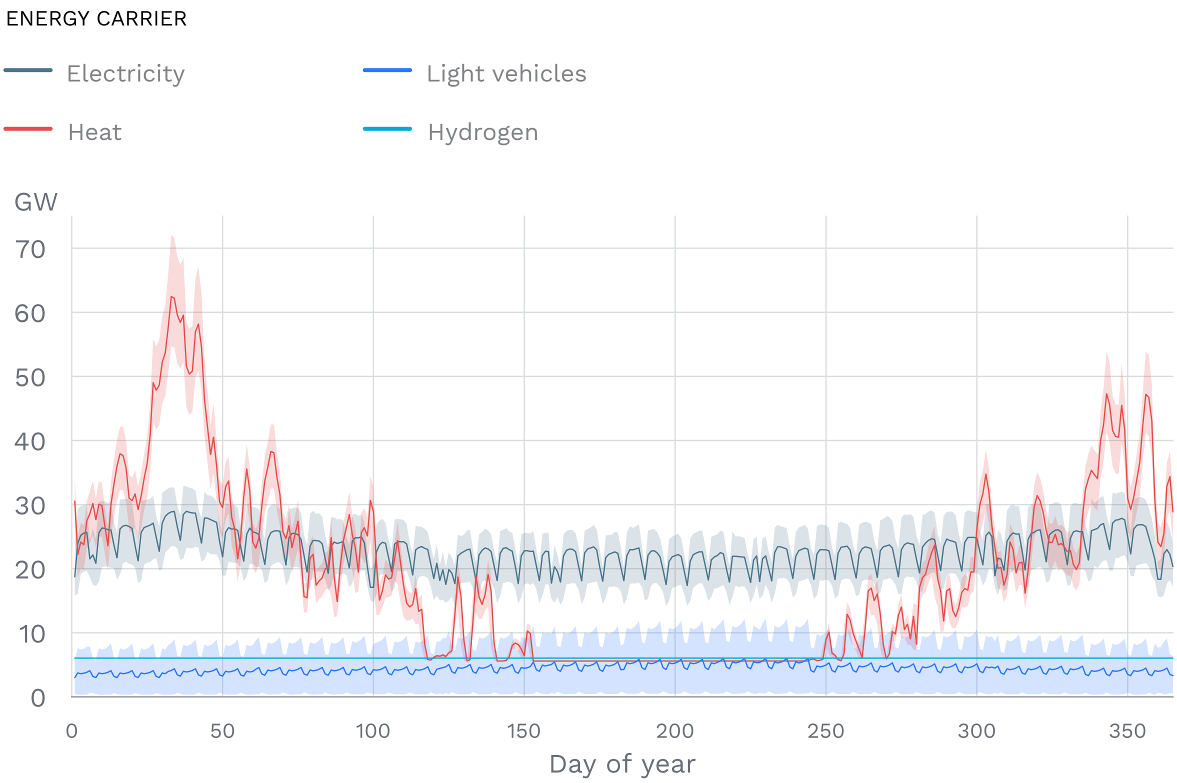
HYDROGEN

- Current hydrogen demand (approx. 1 million tonnes) and domestic hydrogen production capacity from natural gas reforming (approx. 1.3 million tonnes) are based on (MKiŚ, 2021) and expert knowledge.

BIOMASS AND BIOGAS

- We assume the domestic availability of sustainable agricultural biomass at around 20 million tonnes per year (83 TWh) and substrates allowing the annual production of 10 bcm of biogas (66 TWh). This is 60% and 75%, respectively, of the potential assumed by (Czyżak et al., 2021).

FIGURE 29. Daily averages and daily variability of the assumed final use of energy carriers in 2040 (GW) – ambitious RES deployment scenarios (S1, S2)



Source: Instrat's own analysis based on data from ENTSO-E, IMGW, GDDKiA, (Neumann et al., 2023), and own assumptions.
The values shown in the time series have power units, i.e., energy use per hour (GWh/h). These profiles are PyPSA-PL model assumptions and not results. For light road vehicles, we assume that 1 vehicle-kilometre corresponds to approximately 0.18 kWh of mechanical energy, regardless of the type of vehicle. The final use of hydrogen was assumed to be constant over time.

B2. Limitations of the PyPSA-PL model

- A limitation of our methodology is the inclusion of CO_2 emissions arising only at the point of combustion (e.g. a power plant) rather than the total emissions of all greenhouse gases arising from the entire supply chain, e.g. methane emissions from coal mines (Ember, 2020) or fugitive emissions during natural gas transportation (IEA, 2020). The effect of this limitation is that our model clearly identifies natural gas as the energy source with a lower carbon footprint – including the entire supply chain distorts this clarity.

- Similarly, we do not take into account the greenhouse gas emissions and other environmental costs associated with the intentional cultivation of energy crops for biomass-based electricity production. While, according to our assumptions, lower investment costs make biomass a more cost-effective fuel than biogas, the full comparison should be more detailed.

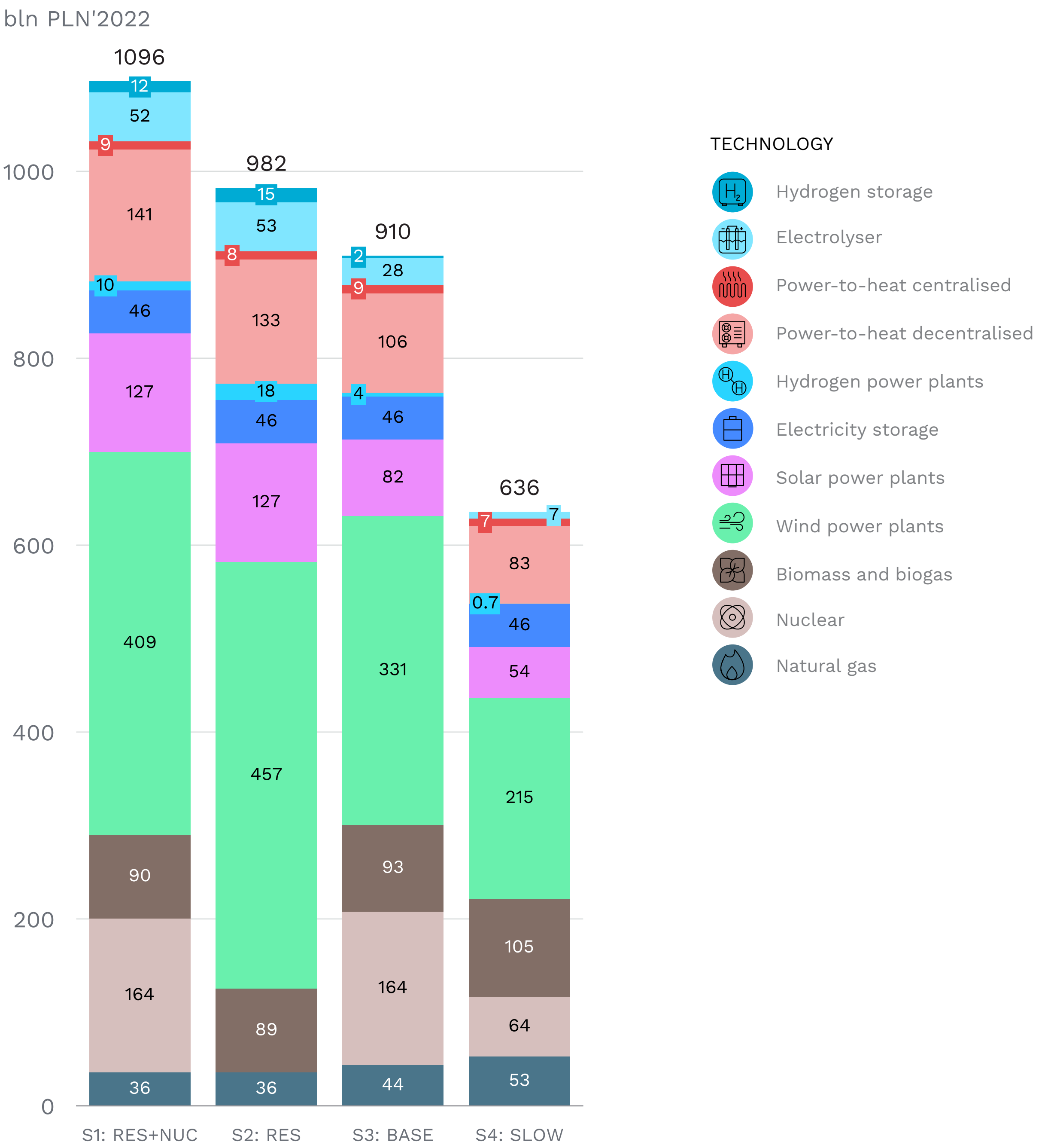
- For obvious reasons, our model also does not take into account the socio-economic spill-over effects of investing in energy infrastructure. The construction of a nuclear power plant is a very different endeavour from the construction of a wind farm, and our model only considers their direct investment cost without the potential gains in terms of new jobs or local supply chain opportunities.

- The current version of our sectorally integrated model also does not take into account grid constraints – we treat Poland's energy system as a 'copper plate' that conducts electricity (and also systemic heat) without constraints. This is a frequently used assumption in energy models. However, it is important to realise that our results may show excessive peak energy flows between generation sources and consumers; taking into account the costs of grid investments may lead to an increase in the cost-effectiveness of investments in electricity storage to support local grid balancing (Levin et al., 2023). This is one of the reasons why the capacity of battery-based electricity storage in our scenarios is not subject to optimisation. In line with industry forecasts, we assume a higher level of installed capacity in those technologies than would result from the optimisation in PyPSA-PL.

- For all these reasons, specific numbers for the installed capacity in different technologies are not our direct recommendations. Our scenarios are also not forecasts – we do not assess the likelihood of their realisation given the complex socio-political conditions. However, the scenarios provide a valuable basis for making recommendations about the future energy system, as they allow us to understand its mechanisms, challenges, and opportunities.

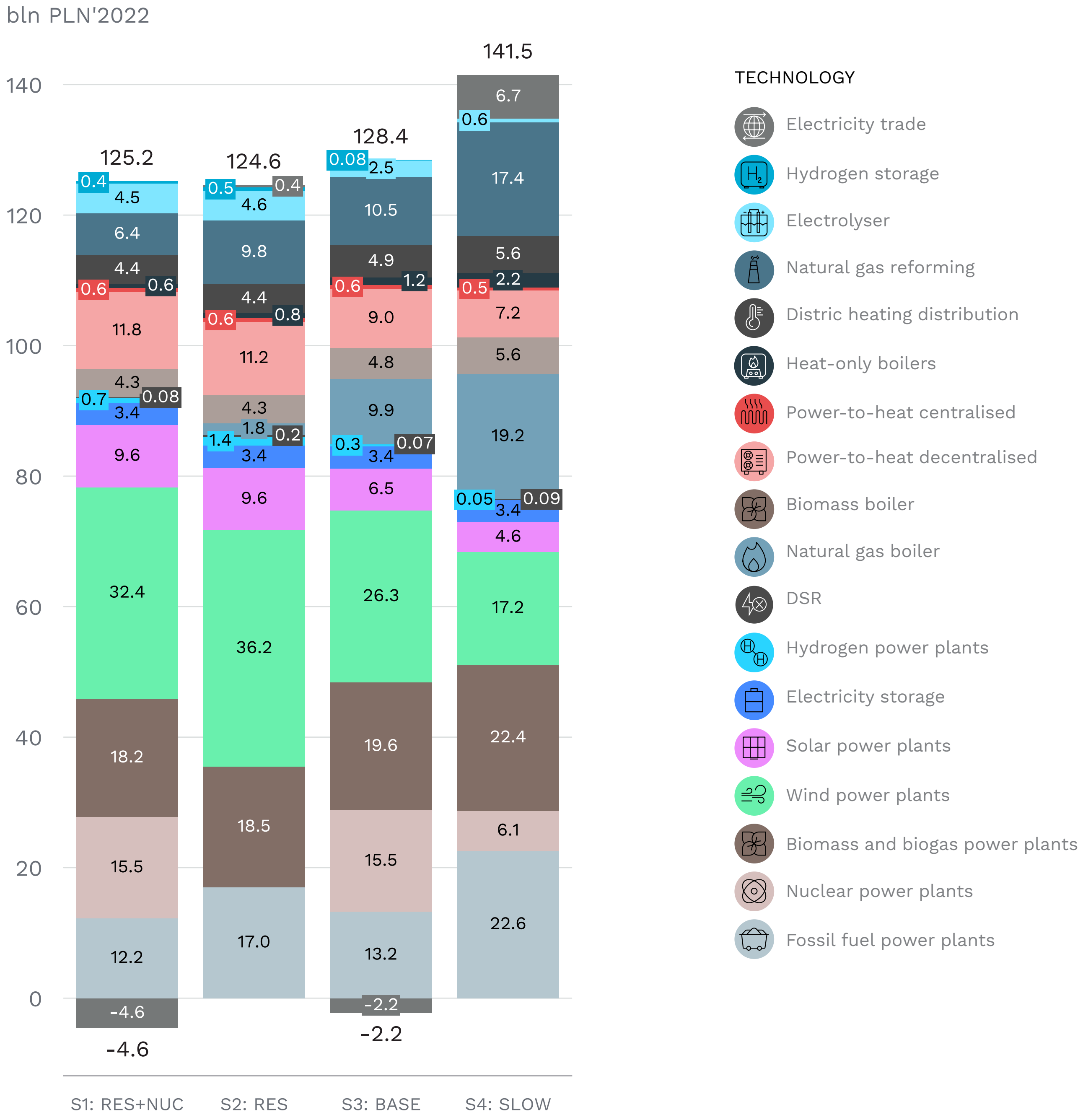
Appendix C – extended data on cost structure

FIGURE 30. Total investment costs in generation and storage technologies in the electricity, heating, and hydrogen sectors in 2026-2040 (billion PLN’2022)



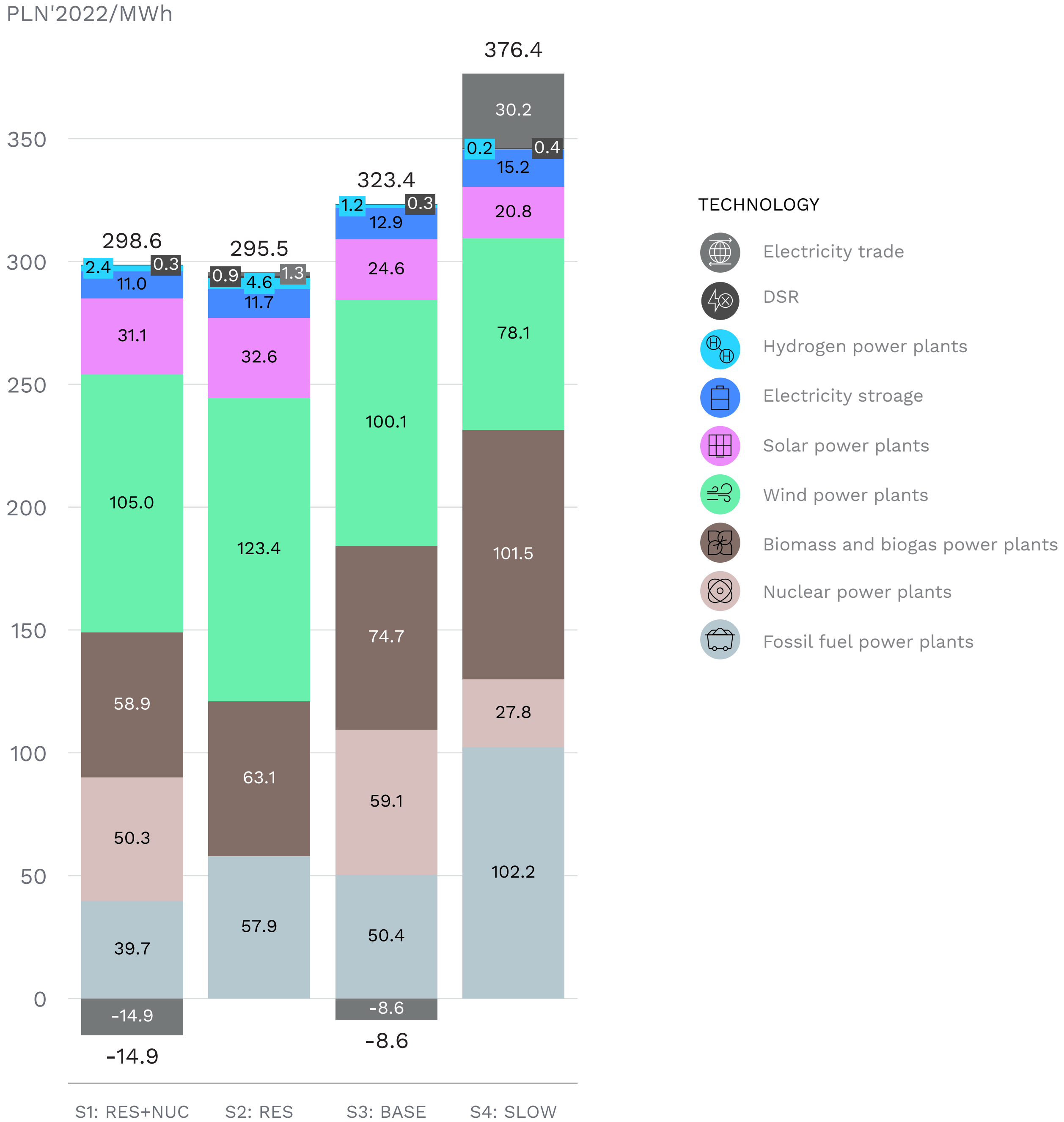
Source: Instrat’s own analysis based on the results of the PyPSA-PL model. Only costs for the investments commissioned between 2026 and 2040 are presented. The Danish Energy Agency (DAE, 2023) is the main source for the unit cost assumptions. Some of these assumptions have been adapted to Polish conditions.

FIGURE 31. Annual system costs in the electricity, heating, and hydrogen sector in 2040 by technology (billion PLN'2022)

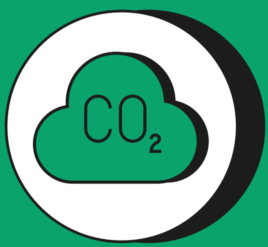


Source: Instrat's own analysis based on the results of the PyPSA-PL model. The cost components included are annuitised CAPEX, annual fixed and variable OPEX costs, including CO_2 emissions. Electricity transmission and distribution costs are not included. Costs related to light vehicle mobility are also present in the PyPSA-PL model. We do not present them here because this sector is not strictly an energy sector. The trade balance of the electricity exchange enters the variable cost component as a cost or revenue (negative cost).

FIGURE 32. Average unit cost of electricity production in 2040 – decomposition by technology (PLN'2022/MWh)



Source: Instrat's own analysis based on the results of the PyPSA-PL model. Costs associated with electricity transmission and distribution were not included. The cost of CO_2 emissions was separated from the variable cost of OPEX. The useful electricity volume was defined as the final electricity use and the sectoral demands related to heat and hydrogen production, minus the energy consumed to produce the hydrogen burned in the power plants. Only infrastructure directly related to electricity generation and storage was included in the cost calculation. The trade balance of the electricity exchange enters the variable cost component as a cost or revenue (negative cost).


CO2