LONG-TERM DECARBONISATION PATHWAYS FOR UKRAINE'S POWER SECTOR

KYIV | BUDAPEST | VIENNA | BRUSSELS

REKK

DIXI Group

Institute for Economics and Forecasting

RAP

Austrian Institute of Technology

The research "LONG-TERM DECARBONISATION PATHWAYS FOR UKRAINE'S POWER SECTOR" was conducted in March-December 2023 by consortium of organisations: REKK, DiXi Group, Institute for Economics and Forecasting of the National Academy of Science of Ukraine, Austrian Institute of Technology, and Regulatory Assistance Project. The aim of the research is to analyse long-term decarbonisation scenarios for the Ukraine power system with quantitative models. The report highlights the economic implications of following net zero pathways for the Ukraine power sector fully integrated to the European power market. The research was conducted to contribute to public debate and decision making on future development of the power sector of Ukraine.

The assessments and conclusions given in this report are those of authors and might not reflect official positions of organisations they represent.

The authors team: REKK, DiXi Group, Institute for Economics and Forecasting of the National Academy of Science of Ukraine, Austrian Institute of Technology, and Regulatory Assistance Project

For questions, please, contact: László Szabó, REKK; email address: laszlo.szabo@rekk.hu

Design: Remarker

European Climate Foundation

This report has been supported by the European Climate Foundation. Responsibility for the information and views set out in this report lies with the authors. The European Climate Foundation cannot be held responsible for any use which may be made of the information contained or expressed therein.

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Ukraine plans to decarbonize its power sector by no later than 2050 and the entire economy by 2060, according to its Energy Strategy and National Economic Strategy. It is an enormous undertaking in a highly uncertain environment. Due to the war, the Ukrainian power sector faces multiple challenges: reconstruction of the damaged network and generation assets and, at the same time, meeting the current and forecasted increase in power needs that accompany rebuilding. In this context, it is fundamental that the transition is carried out in a cost-efficient, socially and environmentally responsible way. This report aims to help this transition planning by analysing long-term decarbonisation scenarios for the Ukraine's power system, using quantitative models.[1] It assesses the feasibility of reaching a net zero power system by 2050 through modelling the adjacent costs in two Net Zero scenarios with different technology portfolios.

The study develops two Net Zero scenarios, in addition to the Reference scenario which reflects the frozen policy and, to a wide extent – frozen technology pathway. The Net Zero–Open Technology scenario is a technology-neutral trajectory, based on an optimistic cost assumption for nuclear technologies (both for large and small modular reactors (SMR)) that is identical to the one used in the Ukraine Energy Strategy. The Net Zero–Renewable energy (RES) scenario assumes higher nuclear investment cost, corresponding to the latest trends observed in Europe. Consequently, this scenario places a primary emphasis on renewables as the dominant technology of the energy transition.

The **assessment shows that decarbonising the Ukrainian power sector before 2050 is feasible, both technically and economically**. Power demand is met in both scenarios in all modelled years. There is sufficient flexible generation to provide adequate reserve capacities, even in the face of demand that, driven by the strong electrification and sector coupling, is anticipated to reach almost three times its current level.

These Net Zero scenarios foresee **90-100 GW new PV and wind capacities by 2050**. After 2035, massive wind development is anticipated to take place, driven by the carbon pricing introduced in these scenarios. Solar development is very dynamic until 2040, when offshore wind grows dynamically. **Reaching net zero is feasible without new nuclear reactors,** meaning that nuclear at the current investment cost level in the European Union (EU) is more expensive than renewables. Ukraine has to follow nuclear investment developments closely to minimise the risk of stranded costs of new reactors. The results also confirm that **rapid coal phase out is possible.** The Net Zero scenarios demonstrate that coal could be completely phased out from the generation mix by 2030, if EU-equivalent carbon pricing was introduced, sufficient renewable capacities were added and the Zaporizhzhya power plant returned to operation in full capacity. Natural gas plants play a bridging role in the energy transition, slightly increasing their contribution to the electricity mix up until 2040 in all scenarios providing system flexibility and later serving as reserve units.

The **total system cost of meeting the increasing energy demand while eliminating emissions is nearly identical to pursuing business-as-usual development** (as in the Reference scenario), despite adding a price to carbon and investing substantial resources in low carbon technologies.

1 The model descriptions and earlier applications could be accessed here: TIMES-Ukraine, EPMM and Green-X

The strong increase in capital investment costs in the Net Zero scenarios, mainly driven by the PV and wind investments, is counterbalanced by the reduction in fuel and CO_2 costs. Moreover, the higher capital investments in both net-zero scenarios are reasoned by the fact that they serve not only power sector development (as in the Reference scenario), but ensure decarbonization of other coupled sectors of economy. The increase in capital investments underlines the **importance of good regulation that can reduce overall financing costs** and foster greater international financing. Good regulation includes long-term planning, predictable regulation of carbon emissions and renewable and infrastructure development, as well as harmonising the application of price caps and other price regulation in Ukraine's wholesale electricity market with those in the EU.

The **net trading position** of Ukraine changes from exporter to importer in the modelled period. Ukraine has substantial exports in all scenarios until 2030 driven by the cost advantage of domestic generation in the absence of CO_2 pricing. In the Net Zero scenarios, post-2030, exports to the EU declines due to the implementation of the ETS in Ukraine. Nevertheless, a net export position is maintained until 2040. Towards the end of the period, Ukraine is likely to become importer of electricity. Although the results also indicate that Net Zero scenarios require lower level of import as the Reference one in 2050, in spite the increasing demand resulting from widespread electrification efforts.

Wholesale electricity prices from 2035 onwards are in the same range in all three scenarios. Before 2035, the lack of carbon pricing makes the electricity price in the Reference scenario 20 €/MWh cheaper, when compared to the Net Zero scenarios. In the wind-dominated Net Zero-RES scenario, the price increase after 2045 demonstrates the risk of an unbalanced technology portfolio alongside various flexibility options (interconnectors and peak load reduction) that can mitigate this potential price increase. The price spreads between Ukraine and the EU in the initial period results **in high utilization of interconnectors for exporting**. Utilization deteriorates after 2030 as price spread gets smaller. Towards the end of the modelled period, both utilization rate and congestion bounce back in the Net Zero scenarios in both trading directions. The high utilisation rates of the interconnectors indicate that **cross-border capacity expansion is key aspect for the future sector development** of Ukraine.

Until 2035, the higher wholesale electricity prices in the Net Zero scenarios will translate into increasing consumer prices. This will require **well-designed support schemes targeting vulnerable consumers:** too-wide coverage would be expensive to maintain for a longer period and would undermine price responsiveness of consumers. Simultaneously, **energy efficiency improvements** should be promoted during the reconstruction phase, as cost-reflective pricing is the most efficient and long-term tool to curtail energy consumption and address energy poverty.

Policy recommendations

Transparency is vital in building public trust and attracting private investment. Establishing clear mechanisms for policy formulation, decision-making, and implementation helps stakeholders understand the rationale behind regulations. Therefore, the Ukrainian government should prioritize transparent communication channels and mechanisms to maintain a strong connection with the public and investors alike. **Public participation** and robust **communication** strategies should be embedded in the regulatory framework to foster a sense of ownership and shared responsibility for the energy transition.

Ensuring **equity** in the distribution of costs and benefits and burdens is a fundamental consideration in the decarbonisation process. Policymakers must prioritise policies that prevent vulnerable populations from disproportionately bearing the costs of the transition. Neglecting equity considerations may result in social unrest, resistance to policy implementation, and a fractured societal approach to decarbonisation.

The development and strengthening of **robust institutions** – competition watchdog, energy regulatory office, consumer protection office – are critical to reducing the country risk premium and attracting private investment. Establishing agencies with the capacity to oversee and enforce regulations ensures a level playing field for all market participants.

INTRODUCTION

Decarbonising the power sector of Ukraine has multiple benefits. The falling cost of wind and solar generation makes the transition affordable. The benefits of resilience and enhanced security of supply thanks to distributed energy sources have been made starkly visible by the war. And the prospect of European integration makes tackling the problem of fossil power plants emissions even more urgent.

Yet it will be no easy task. The sheer scale of the challenge is enormous and competing priorities of rebuilding transport infrastructure, homes and industries will definitely spread available human and financial resources very thin. UNDP estimated in March 2023 the cost of reconstruction to be $411 billion, and this amount probably increased significantly since then.[2]

Therefore, it is imperative that the transition is planned and supported with **least cost, highest benefit and lowest risk** pathway in mind. Low hanging fruits need to be harvested first, before moving into more costly and uncertain solutions. And what is most important, private capital needs to be mobilized, as the scale of the challenge will not be able to be met with Ukrainian public funds and donor contributions alone.

Due to the destructions of the war, the Ukrainian power sector faces multiple challenges: reconstruction of the damaged network and generation assets and at the same time meeting the present and expectedly increasing power needs with the reconstruction of the country. This report aims to help this transition planning as it analyses long-term decarbonisation scenarios for Ukraine's power system with quantitative models. It assesses the feasibility of reaching a net zero power system by 2050 with the adjacent costs in two net zero scenarios with different technology portfolios. Ukraine plans to decarbonize its power sector by no later than 2050, and the whole economy by 2060.

The questions we aim to answer:

- What are the implications of integrating Ukraine into the EU power market?
- How power generation mix needs to evolve to decarbonize the power sector of Ukraine by 2050, based on the overall decarbonization goal of Ukraine by 2060? More specifically:
  - What is the future role of nuclear power? Does Ukraine need new nuclear capacity?
  - How much coal-fired generation is needed to securely satisfy electricity demand in the coming winters? Can coal-fired power plants be closed down by 2035?
  - What is the optimal portfolio of renewable energy technologies and geographical distribution?
- How to provide the necessary system flexibility and what is the role of fossil gas-based power plants?

2 UNDP, March 2023 Costs to rebuild Ukraine increase sharply | United Nations Development Programme (undp.org)

- What is the impact of introducing EU Emission Trading Scheme - ETS (or equivalent) for power generation and trade in Ukraine? And of the application of carbon border adjustment mechanism (CBAM)?

Several limitations of our assessments warrant emphasis. Notably, the lack of detailed grid modelling of the Ukrainian power system, as EPMM only models the cross-border capacities in a stylized NTC based approach, but not the physical network. The exact damages inflicted upon the Ukrainian energy infrastructure remain unknown in the time of modelling, and the conclusion of the war, with its potential impact, introduces a considerable level of uncertainty into the assessment. Furthermore, our assumptions include the full territorial integrity of Ukraine during the post-war recovery period, which introduces additional uncertainties into the analysis. The TIMES-Ukraine model has limitation concerning international trade, as it covers the Ukraine energy system. This limitation is solved by the parallel use of EPMM, but this required iterations between the models. These limitations underscore the need for cautious interpretation of the findings and acknowledgment of the uncertainties inherent in the assessment due to the complexities involved in the dynamic and evolving circumstances in Ukraine.

The structure of the report is as follows. First, we describe the scenarios, the assumptions used and the way the models were linked to be able to address the questions of the study. Then we discuss the results, and finally conclude with recommendations for efficient and equitable decarbonization of Ukraine's power system.[3]

3 During the implementation of the project, the project team held two rounds of consultations with stakeholders (sector experts, energy and climate-related NGOs and think-thanks, Members of Parliament, etc.) to discuss and better shape crucial research/policy questions, the modelling approach, assumptions and scenarios.

SCENARIO DESCRIPTION

We assess three core scenarios and one sub-scenario. The Reference scenario represents a business-as-usual economic development, characterized by moderate increase of electricity demand and no decarbonization goal. The Reference-CBAM sub-scenario quantifies the impacts of CBAM on the Ukraine power sector. This alternative scenario is discussed separately in the Results section.

The Reference scenario is contrasted with two Net Zero scenarios. They both target the decarbonisation of the power sector before 2050 and assume increasing power demand due to electrification and sector coupling. The emissions trajectory includes a more rapid reduction of emissions at the beginning and slower rates of reduction by the end of the horizon (see Annex 6: Detailed results tables for Ukraine power sector in the four assessed scenarios). Such pathway provides a more uniform allocation of new installations and thus investments need until 2050. The two net zero scenarios assume, however, different costs for nuclear energy. The Net Zero-Open Technology (NZ-OT) (and the Reference scenario) uses the low-cost estimate for nuclear investment from the Energy Strategy of Ukraine. The Net Zero – Renewable scenario (NZ-RES) uses a more realistic, higher nuclear investment cost. Apart from the impacts of resulting nuclear capacity the net zero scenarios forecast the level of renewable capacity and generation required for the transformation of the power sector. System wide impacts, such as reserve capacity needs and their hourly availability, RES curtailment and energy not supplied (ENS) values are calculated for each of these scenarios. The key assumptions of the scenarios are summarised in the following table.

Table 1: Key assumption of the scenarios

	Reference	Sub-scenario Reference + CBAM*	Net Zero Open Technology	Net Zero Renewable
Population, GDP	same for all scenarios			
Carbon pricing	no	CBAM	EU ETS prices	
RES potential	low		high	
Nuclear	SMR not available; large scale available (5250 €/kW)		Both technologies are available (5250 €/kW)	Both technologies are available (7000 €/kW)

**Note: The alternative Reference + CBAM scenario results are presented in a separate section*

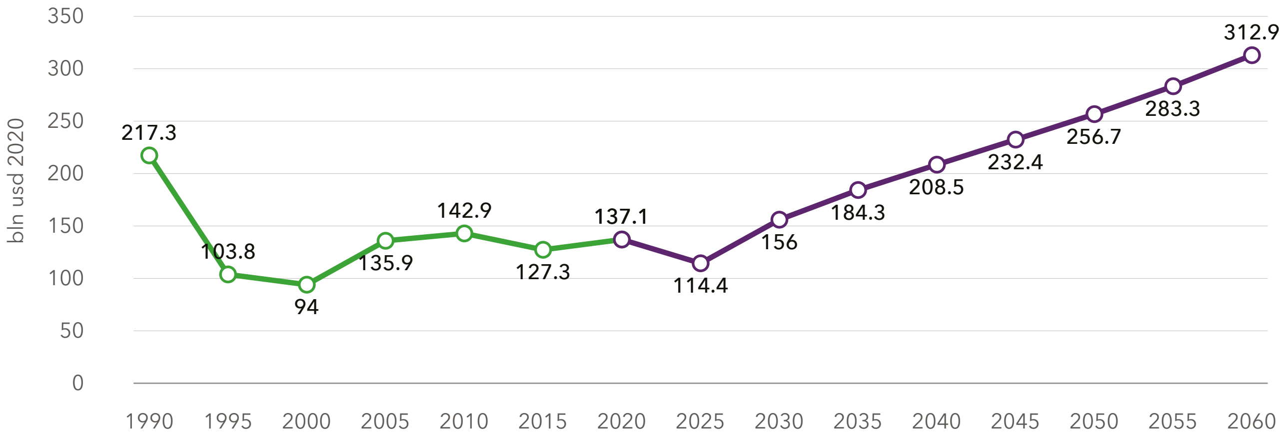
MODELLING ASSUMPTIONS

Economic development

The war has severely impacted Ukraine's economy, destroyed part of the country's infrastructure, including the energy infrastructure. However, the successes of military defence, the coordinated effort of the Ukrainian government and businesses, the indomitable spirit of Ukrainian people and the support of international partners resulted in lower-than-expected economic recession. GDP dropped by 29.1% in 2022 compared to the 40-50% estimated at the beginning of the invasion. Inflation was also less dramatic than expected (26.6%).

The economic projection of the National Bank published in July 2023 and used in this study was more optimistic: the drop of GDP in 2022 should be followed by an increase of +2.9% in 2023, +3.5% in 2024, and +6.8% in 2025.[4] In this study, we have used the macroeconomic assumptions of the 'Energy Strategy for 2050' adopted in 2023: it assumes 5.4% annual growth between 2023 and 2032 and 2.3% annual growth for 2033-2050. The Reference scenario assumes no change in the structure of demand by 2050. Electrification in the Net Zero scenarios impacts the structure as shown in Figure 6.

Figure 1: GDP development and forecast (2023-2050)



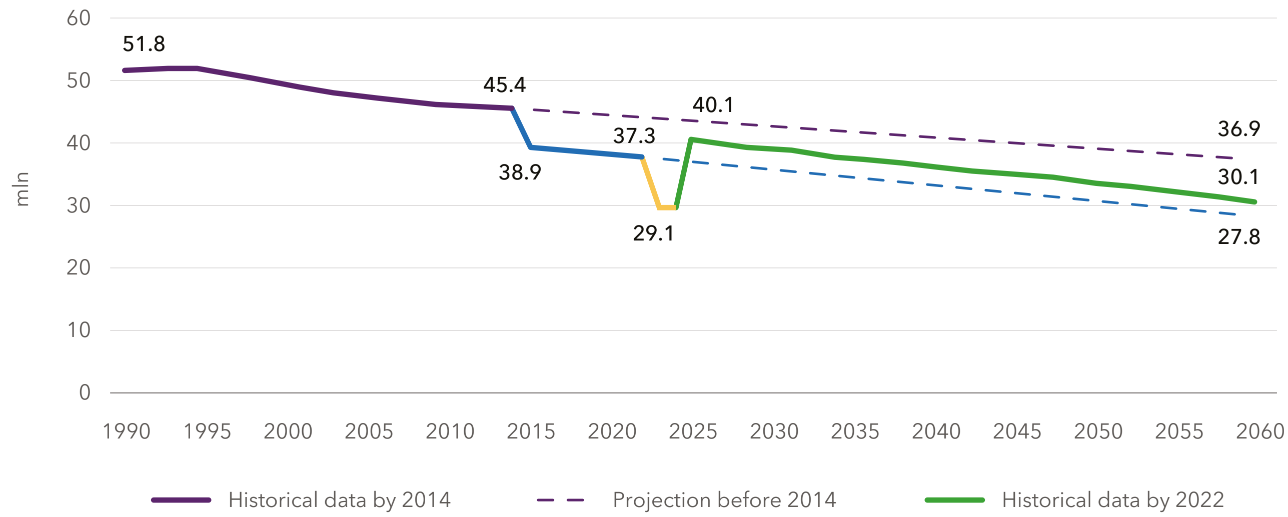
Source: National Bank of Ukraine. Inflation report. July 2023. https://bank.gov.ua/en/news/all/inflyatsiyniy-zvit-lipen-2023-roku https://bank.gov.ua/en/news/all/inflyatsiyniy-zvit-lipen-2023-roku

4 Based on the report of National Bank of Ukraine. Inflation report. July 2023. https://bank.gov.ua/en/news/all/inflyatsiyniy-zvit-lipen-2023-roku

Demography

As of May 23, 2023, 5.4 million refugees fled Ukraine and recorded across Europe[5], although 77% of them intend to return[6]. In this study war victims and internal migration are not counted, occupied territories are considered from 2025. The study uses the medium scenario (solid blue line) from 2025. The population shrinks from 40.1 m to 30.1 m by 2060.

Figure 2: Demographic development and forecast



Source: Institute for Demography and Social Studies. National demographic projection. October 2020. – Available from: https://idss.org.ua/forecasts/nation_pop_proj.

Generation capacities

- We used the following assumptions with regards to generation capacities, also considering the damage made to this infrastructure during the war:
- The lifetime of existing nuclear power plants (NPPs) gets extended as declared by EnergoAtom. The damaged Zaporizhzhya NPP is expected to return to operations between 2025 and 2030. Future nuclear generation capacity is capped in the TIMES-Ukraine model as defined by the Ministry of Energy[7] at 18 GW new large units (in all scenarios) and 40*160 MW Small Modular Reactor (SMR) units (in net zero scenarios).
- Thermal generation capacities captured by the Russian Federation are assumed to be available to operate from 2025 onwards. These capacities operate under actual or improved technical performance after being modernized by the year specified in the NERP (National Emission Reduction Plan). Modernised plants would meet the requirements of the Industrial Emissions Directive.
- Renewable generation, including various categories of solar, wind, hydro and biomass, have different investment and O&M costs, and potential reflecting the policy priorities and complexity of developing new facilities.

5 https://data.unhcr.org/en/situations/ukraine
6 https://razumkov.org.ua/napriamky/sotsiologichni-doslidzhennia/ukrainski-bizhentsi-nastroi-ta-otsinky
7 https://ua-energy.org/uk/posts/yaroslav-demchenkov-postupovo-do-2035-roku-realno-vidmovytysia-vid-vuhillia

Technical and economic parameters of existing power plants, such as capacity factor[8] and efficiency, were estimated as an average of actual performance parameters for the past 5 years. For new technologies these parameters were taken from various sources (see Annex 2 and 3 for details).

Carbon price

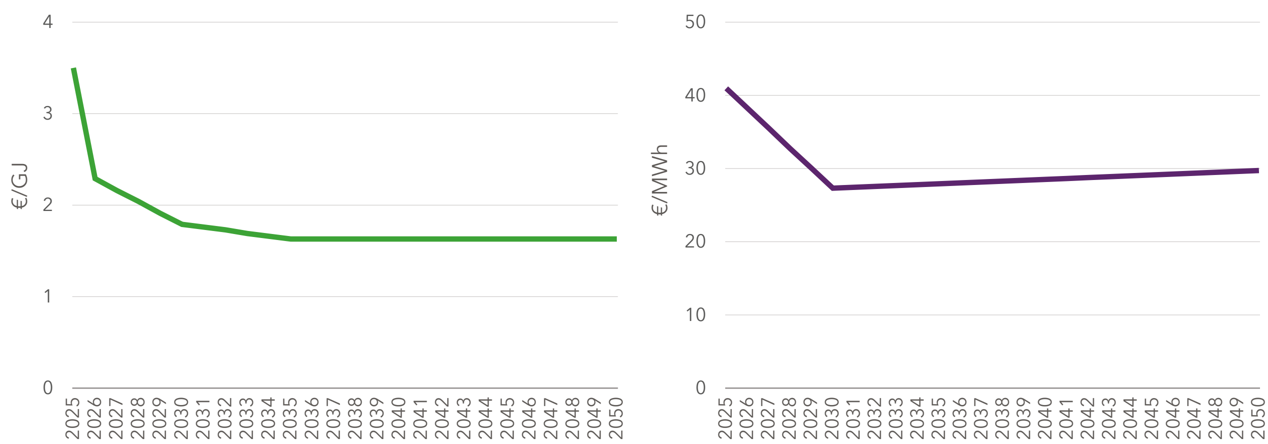
The current level of national carbon price is used in the Reference scenarios. The Reference+CBAM scenario, however, assumes the introduction of CBAM in 2030. This scenario uses a CO_2 emission factor that equals the CO_2 intensity of the modelled fossil-based generation in Ukraine. It varies between 0.57 and 0.72 tCO_2/MWh in the assessed period. The tariff equals this intensity multiplied by the ETS price. The ETS price used in the net zero scenarios for the power sector is the following: 2025-30: No ETS price, 2030: 80 €/tCO_2, 2040: 85 €/tCO_2, 2050: 160 €/tCO_2, while for other sectors the price is not specified, thus the marginal price is estimated by the model.[9]

Fuel prices

For coal we used the forecast of the World Energy Outlook (IEA WEO, 2022). IEA projects substantial price reduction in the next few years, down to approximately 1.5 €/GJ by 2030 that remains relatively stable thereafter.

Fossil gas price for each country is a modelled output of the gas market model of REKK (EGMM). These prices are consistent with the IEA WEO (2022) forecasts. Specifically, both the TTF and Ukrainian gas prices are expected to be around 40 €/MWh in 2025, experiencing a subsequent decrease to approximately 27 €/MWh by 2030. Following this decline, there is a slight increase in prices for the remaining duration of the modelled period.

Figure 3: Ukrainian coal and natural gas prices used in the modelling



Source: IEA WEO, 2022 and REKK

8 Due to limitations of the TIMES-Ukraine modelling, capacity factor means the highest expected annual utilization factor due to technical availability and competitiveness in dispatch. Actual model utilization rate could be lower.

9 European Commission: Recommended parameters for reporting on GHG projections in 2023 for the NECP revision reports

Cross border capacities

Net Transfer Capacity (NTCs) figures for Ukraine use the most recent available data of the country's Ten-Year Network Development Plan (TYNDP).[10] Capacities used in the modelling are limited to 66% of the reported values for 2025 and 2030 due to challenges associated with synchronization with the ENTSO-E grid. All other existing and planned cross-border capacities are from the European Network of Transmission System Operators for Electricity (ENTSO-E) TYNDP 2022. Detailed NTC figures are in Annex 1: Assumptions on net transfer capacities (NTCs).[11]

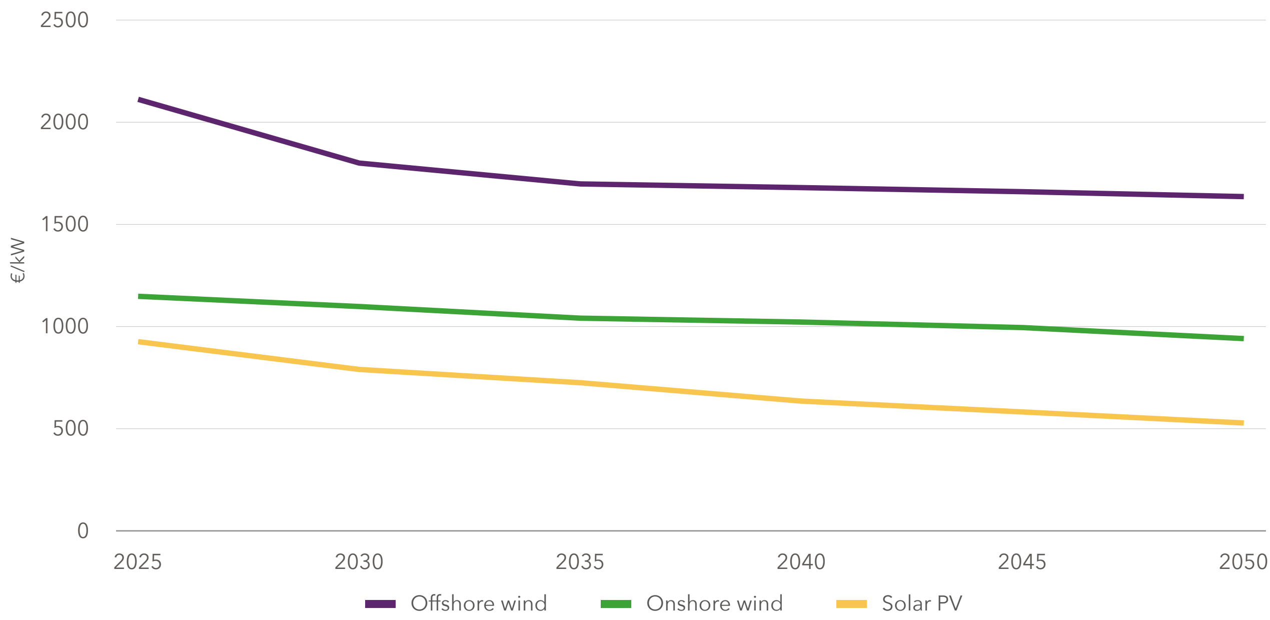
System reserves

In determining the reserve requirements for the year 2025, we have considered the existing aFRR reserves, estimated at approximately 1000 MW/h for upward regulation and 400 MW/h for downward regulation. From 2025 onwards we anticipate an increasing need for reserves due to the surging load and variable renewable generation. The requirement is estimated on the basis of regression using historical data of 16 European countries over a period of 7 years.

Investment cost of variable renewables

Investment cost of all variable renewables reduce over time: solar more than wind. There is a steeper decrease between 2025 and 2030 for offshore wind. These assumptions are taken from the Danish Energy Agency.[12]

Figure 4: CAPEX of PV, onshore and offshore wind in the modelled years



10 Due to martial law, Ukrainian TYNDP is not publicly available.

11 Detailed description of planned cross-border capacities can be accessed: https://tyndp2022-project-platform.azurewebsites.net/projectsheets

12 https://ens.dk/en/our-services/projections-and-models/technology-data/technology-data-generation-electricity-and

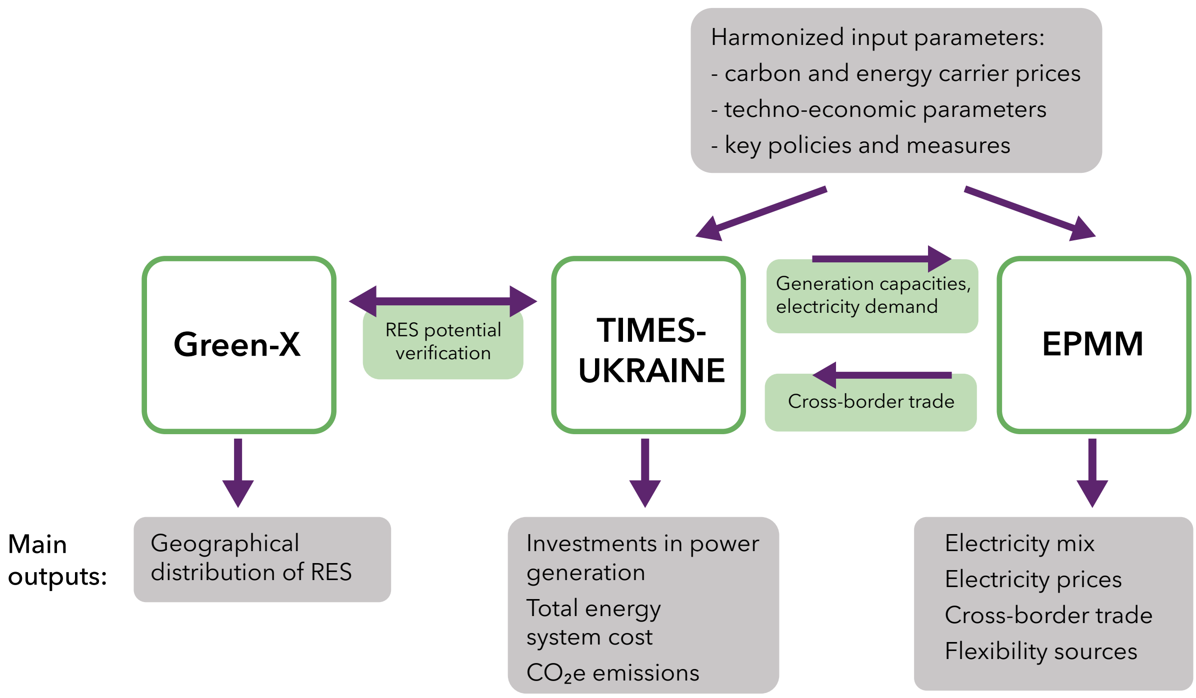
METHODOLOGY

The analysis was conducted with the synchronized application of three distinct energy models: TIMES-Ukraine, European Power Market Model (EPMM) and Green-X model (Green-X).

TIMES-Ukraine is an all-encompassing energy sector model tailored for Ukraine, capable of optimizing investment decisions and calculating total system costs. EPMM is a European power dispatch model capable of capturing cross-border electricity trade dynamics. Green-X is a renewable energy model which was used to assess renewable potential and spatial distribution.

The three models used harmonised assumptions and were applied in iterations. Interlinkages are summarised in the following figure.

Figure 5: Model interlinkages



Modelling started with TIMES-Ukraine estimating the optimal generation capacity portfolio in the scenarios on the basis of assumed GDP, technology investment costs, carbon and fuel prices, coupled with key policy measures. Renewable capacities were validated by the renewable potential data of the Green-X model.

Estimated capacity mix is the result of the least cost optimization made by the TIMES-Ukraine model with consideration of the technical parameters of generation technologies, and also system requirements. The use or phasing out of specific generation technologies are not exogeneous (except for the planned phaseout of NPP units announced by EnergoAtom) but model outputs.

This capacity mix then served as an input for the EPMM model. While maintaining consistency with the input assumptions of the TIMES-Ukraine model, EPMM estimated the evolution of cross-border trade that was subsequently fed back into the TIMES-Ukraine model.

Through this iterative process, the updated electricity export-import values enabled the estimation of the final generation capacity figures, enabling the calculation of total energy system costs and carbon-dioxide emissions with the TIMES-Ukraine model. EPMM, in turn, estimated electricity generation mix, electricity prices, cross-border trade, and checked the availability of reserves. Finally, the Green-X model determined the optimal geographical allocation of renewables investments.

Carbon targets

While there are no specific emission reduction targets in the Reference scenario, in the Net Zero scenarios CO_2 emissions are constrained separately for the power generation sector, and for the whole economy in general. The power sector is supposed to reach full decarbonization no later than by 2050, and the whole economy – by 2060. The decarbonization pathway is set as a concave curve (see Figure 14) that assumes more rapid reduction of emissions at the beginning and slower rates of reduction by the end of the horizon. Such pathway provides more uniform allocation of new installations and thus – required investments over the period.

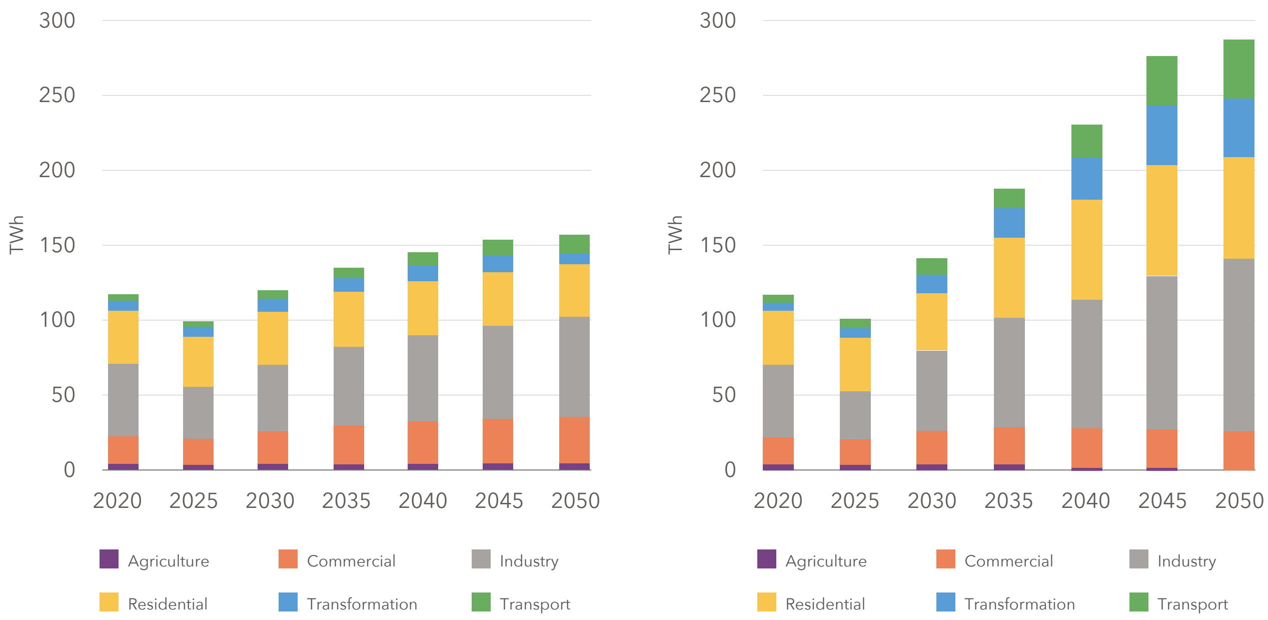
RESULTS

Electricity demand

Owing to the assumed moderate pace of economic recovery (L-shaped recovery) and conservative demographic projection, the electricity demand in the Reference scenarios recovers gradually and at a much lower rates than the development of macroeconomic drivers (decoupling). Moving towards a less energy intensive service-based economy and the implementation of additional energy-efficiency measures mitigates the demand growth rate further. Return to pre-war consumption level in the Reference scenario is expected only after 2040, reaching 157 TWh in 2050.

Electrification in all sectors of the economy is much more dynamic in the net zero scenarios: complete electrification of light-duty vehicles by 2050, moderate electrification of freight and industry, heating, cooking and water heating. Hydrogen production as new load appears from 2030. By 2050, total electricity consumption increases to more than the double of 2020 levels (to 286 TWh).

Figure 6: Demand projections for Reference (left) and Net Zero scenarios (right)

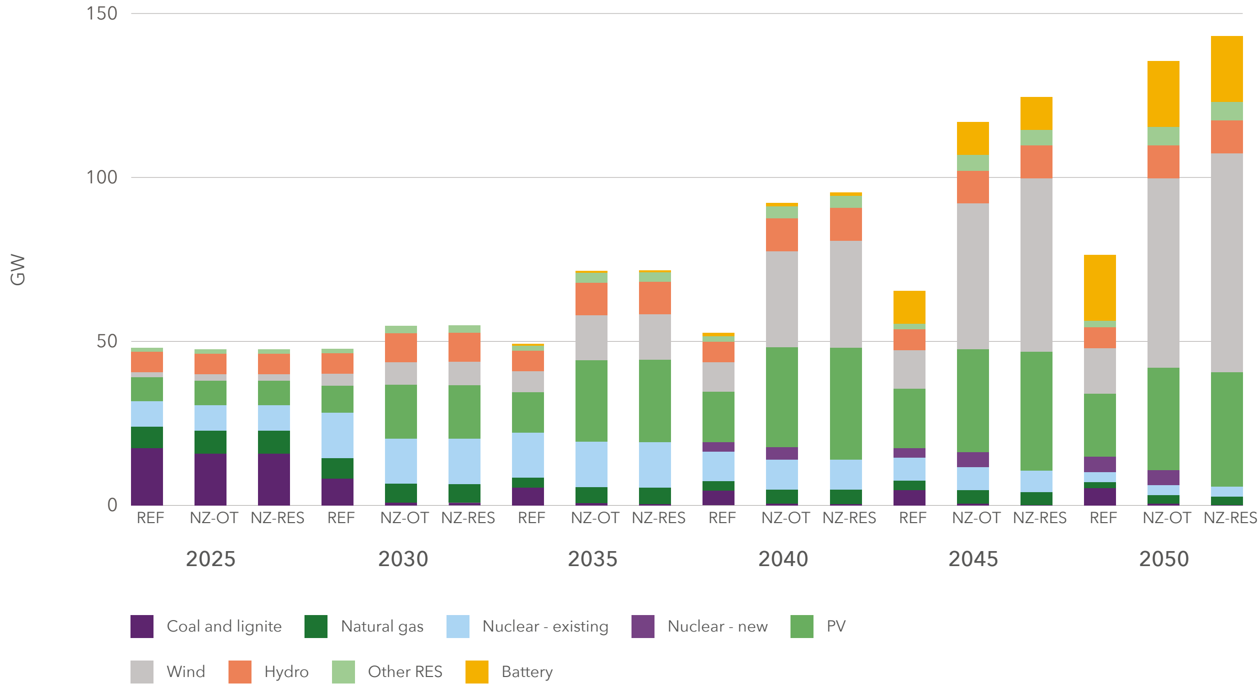


Source: TIMES-Ukraine

Capacity mix

On the basis of these assumptions the TIMES-Ukraine model estimated the following generation capacity mix.

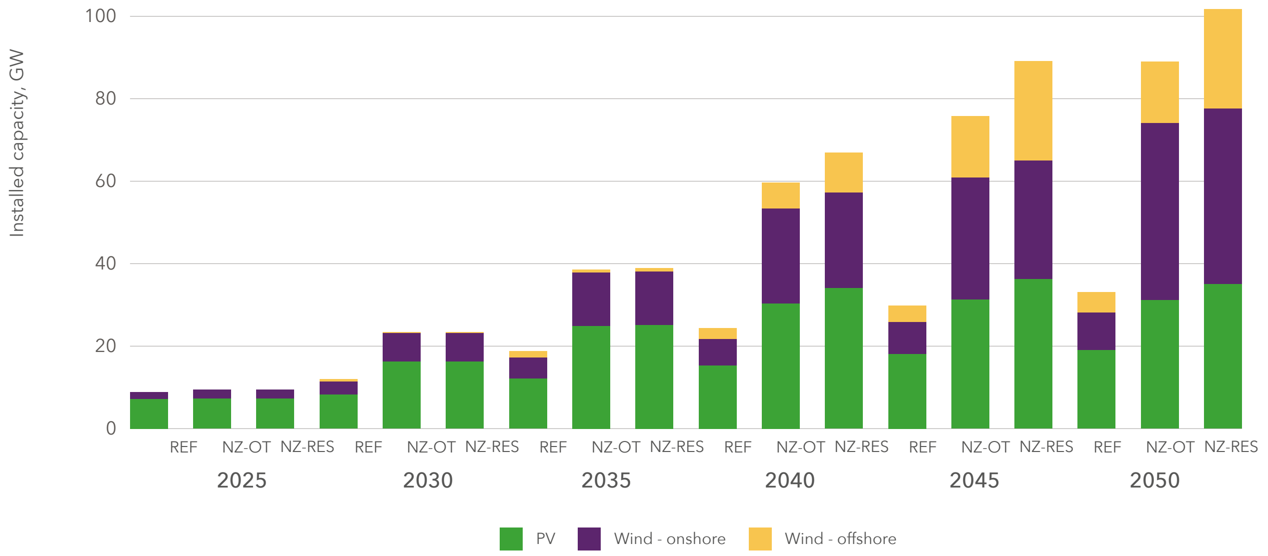
Figure 7: Power generation capacity per technology, GW



Source: TIMES-Ukraine

While in the Reference coal and lignite play important role in all years with 5 GW remaining capacities even in 2050, in the Net Zero scenarios coal virtually gets phased out by 2030. Nuclear capacities remain in the capacity mix with approximately 8 GW in 2050 in the Reference and Net Zero-OT scenarios - roughly at similar level as today (considering occupation of Zaporizhzhia NPP) - but only with 3 GW in the Net Zero-RES scenario. Large renewable investments take place in both. The significant increase in hydro capacities in the Net-Zero scenario between 2025-2035 are the plans of UKRENERGO. Such huge developments warrant environmental and social assessment. Battery capacity is exogenous in the model and the same in all 3 scenarios.

Figure 8: PV and wind generation capacity, GW



Source: TIMES-Ukraine

In the Reference case less than 40 GW variable renewable capacity gets built by 2050 whereas in the Net Zero-OT scenario 90 GW and in the Net Zero-RES scenario more than 100 GW. The uptake dynamics of wind and PV is quite different due to their assumed economic and technical characteristics. PV capacity increases rapidly in the beginning of the period but levels after 2040. Wind capacities buildout becomes especially dynamic after 2035 with offshore wind contributing significantly. As a result, by the end of the modelled period the power system becomes wind dominated in both net zero scenarios.

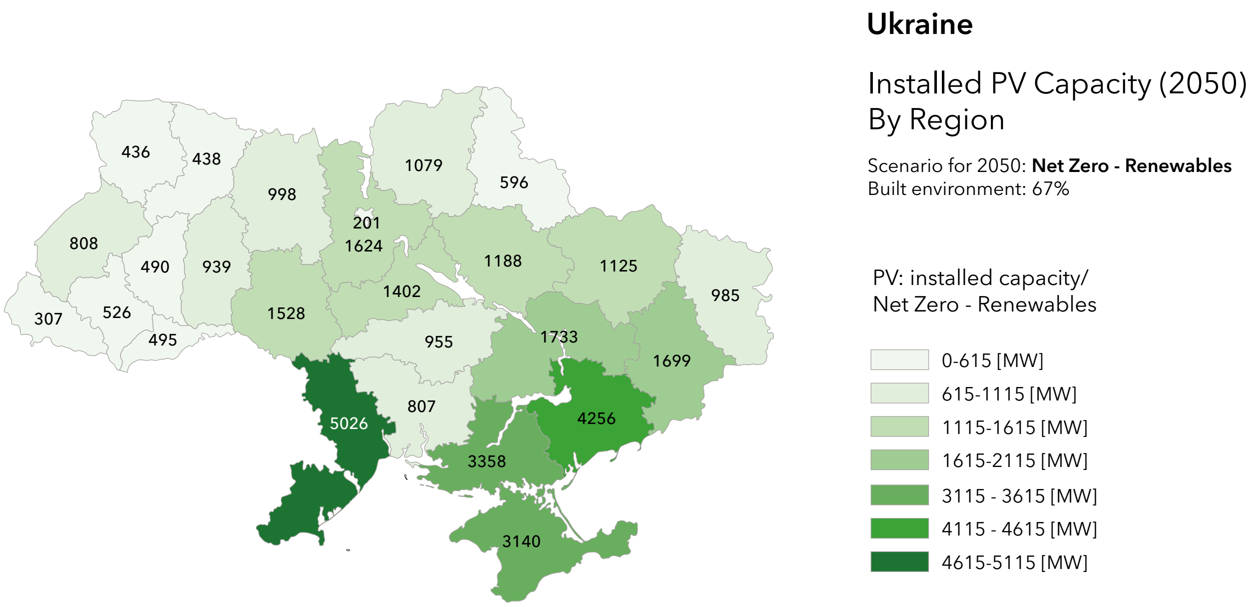
Geographical distribution of solar and wind

This section provides an indicative regional breakdown of the necessary wind and solar PV installations for the energy scenarios presented. More precisely, below for both technologies an indicative regional distribution of the 2050 installed capacities is shown for all three scenarios, including the Reference, the Net Zero-OT and the Net Zero-RES scenarios. The approach for conducting the regional distribution acknowledges the resources at hand but differs by technology – as described below. Further details on the regional distribution, including apart from 2050 also other years (2030, 2040) as well as a comparison with the outcomes of a corresponding resource assessment, can be found in Annex 7.

As applicable therein, the Ukraine offers promising sites for wind and solar PV development. Specifically **for wind, the resources and related site qualities can be classified as excellent**, including some of the best onshore wind sites across the whole European continent.

For **solar PV** the allocation of installed capacities to individual regions of Ukraine differs by technology subcategory. For small-scale PV systems installed at the built environment the available areas at a regional level are the determining factor whereas for large-scale PV systems installed at free fields the resource quality is assumed to predetermine the allocation process. Thus, for those type of PV systems the top five regions in terms of resource qualities (i.e., by means of region-specific average full load hours) are selected and installed PV capacities are distributed according to available area potentials (including mainly agricultural areas). To limit conflicts with food production, the assumption is taken that the majority of PV systems falls under the classification small-scale at the built environment as shown in Table 2 (i.e., 75% of all PV systems in the Reference scenario, two thirds of all PV systems in the Net Zero scenarios where the overall PV exploitation is significantly larger in magnitude).

Figure 9: Ukraine's regional distribution of 2050 cumulative PV capacities for the Net Zero-RES scenario



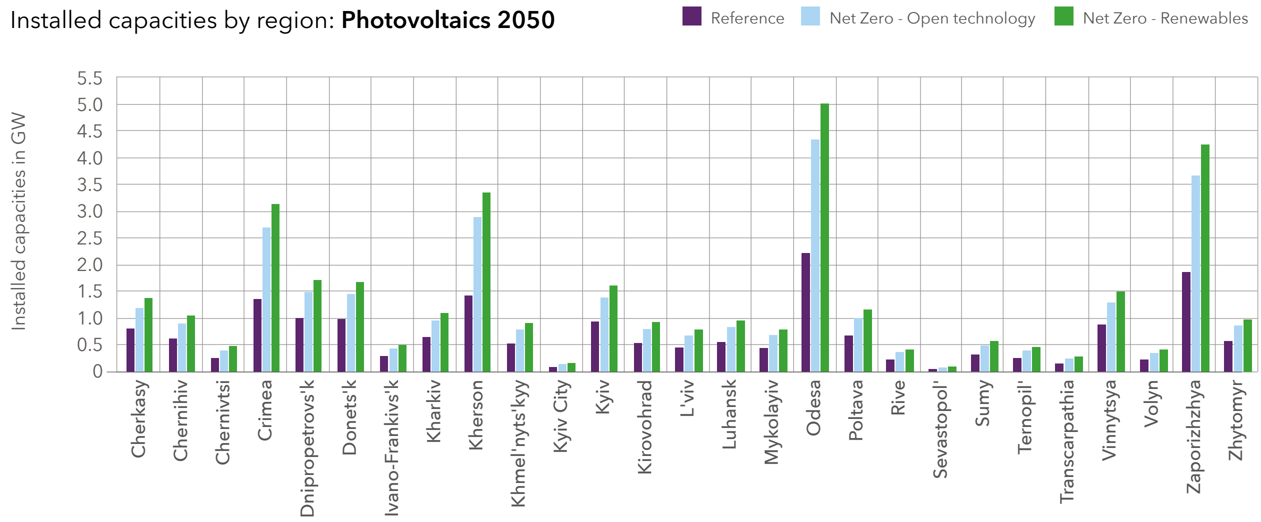
Source: own assessment

Table 2: Breakdown of 2050 total installed PV capacity (in GW) in Ukraine by category

Breakdown of 2050 total installed PV capacity (in GW) by category	**Reference** scenario	**Net Zero - OT** scenario	**Net Zero - RES** scenario
Small-scale PV systems (built environment)	14.3	20.9	24.2
Large-scale PV systems (free field)	4.8	10.5	12.1

Source: own assessment

Figure 10: Cross-scenario comparison of Ukraine's regional distribution of 2050 cumulative PV capacities

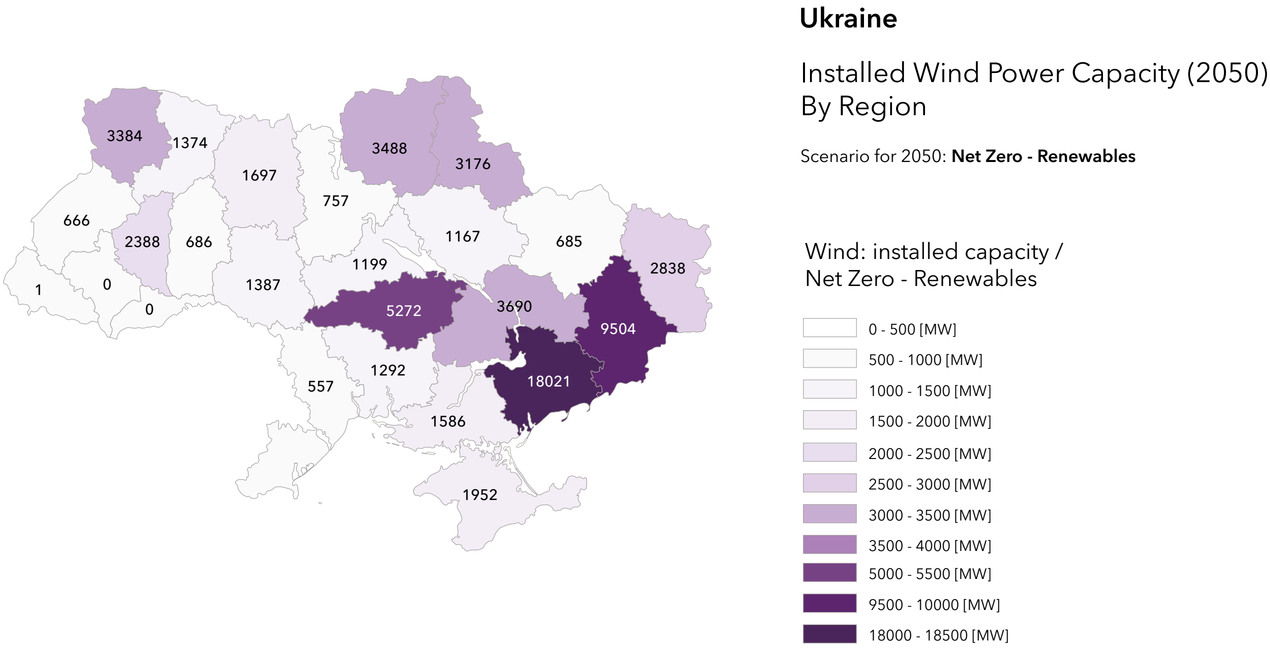


Source: own assessment

Figure 9 above illustrates the outcomes of the regional distribution of PV capacities by 2050 for the Net Zero-RES scenario. This is the scenario with the highest PV exploitation across all three scenarios as applicable from Figure 10, which offers complementary to Figure 9 a cross-scenario comparison of the regional breakdown of installed PV capacities by 2050. As applicable from these depictions, the highest exploitation occurs in regions in the south and southeast of the Ukraine where resource qualities are highest for solar PV.

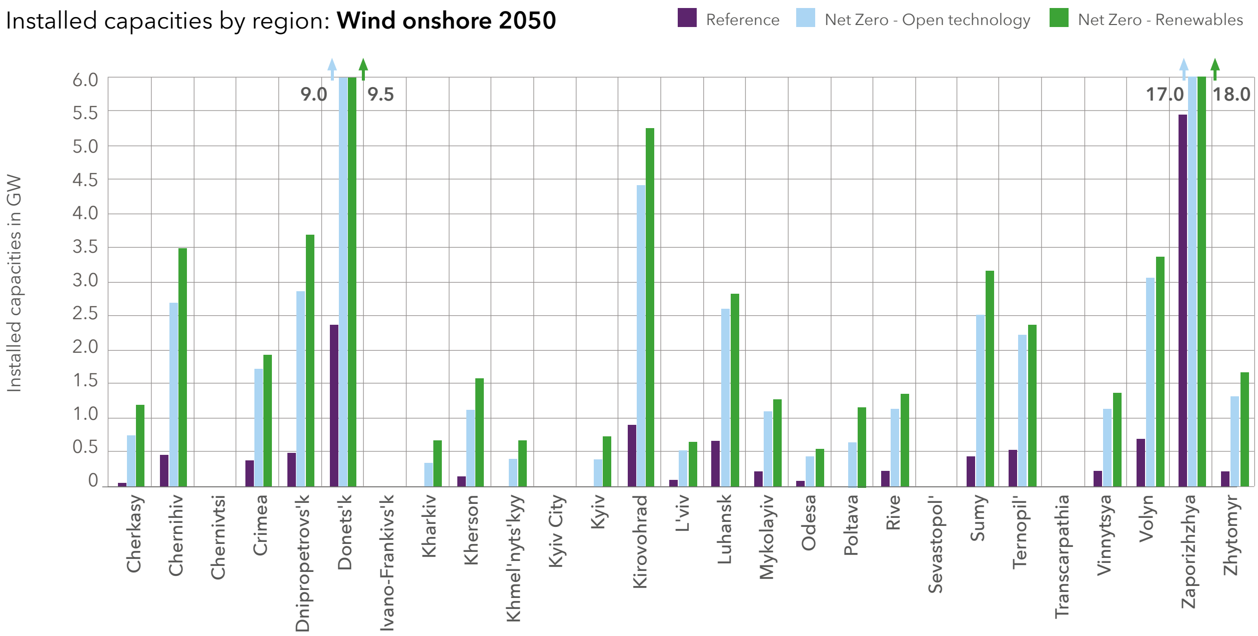
For **onshore wind** the allocation of installed capacities to individual regions of Ukraine follows a least-cost principle and consequently acknowledges the resource quality of available wind sites across the whole country. The outcomes of the regional distribution of wind onshore capacities by 2050 are illustrated in *Figure 11* for the Net Zero-RES scenario. Similar to PV, this is the scenario with the highest wind exploitation across all three scenarios. Complementary to that, *Figure 12* adds a cross-scenario comparison of the regional breakdown of installed wind onshore capacities by 2050. These illustrations show that the highest exploitation is planned for regions in the southeast of Ukraine where resource qualities are highest for wind onshore.

Figure 11: Regional distribution of 2050 cumulative wind onshore capacities for the Net Zero-RES scenario



Source: own assessment

Figure 12: Cross-scenario comparison of the regional distribution of 2050 cumulative wind onshore capacities



Source: own assessment

Apparently, an extended part of the planned wind uptake falls under currently (as of January 2024) occupied territory. Even when leaving out those areas and redistributing the required uptake among non-occupied territories, the identified resource potential for onshore wind in the Ukraine would easily suffice to meet the needs identified in energy modelling and that would only to a negligible extent reduce the economic viability. As discussed in Annex 7, Ukraine has a significant amount of excellent wind sites on its territory. Those sites are comparable to some of the best sites at the Northern coast of the European continent.

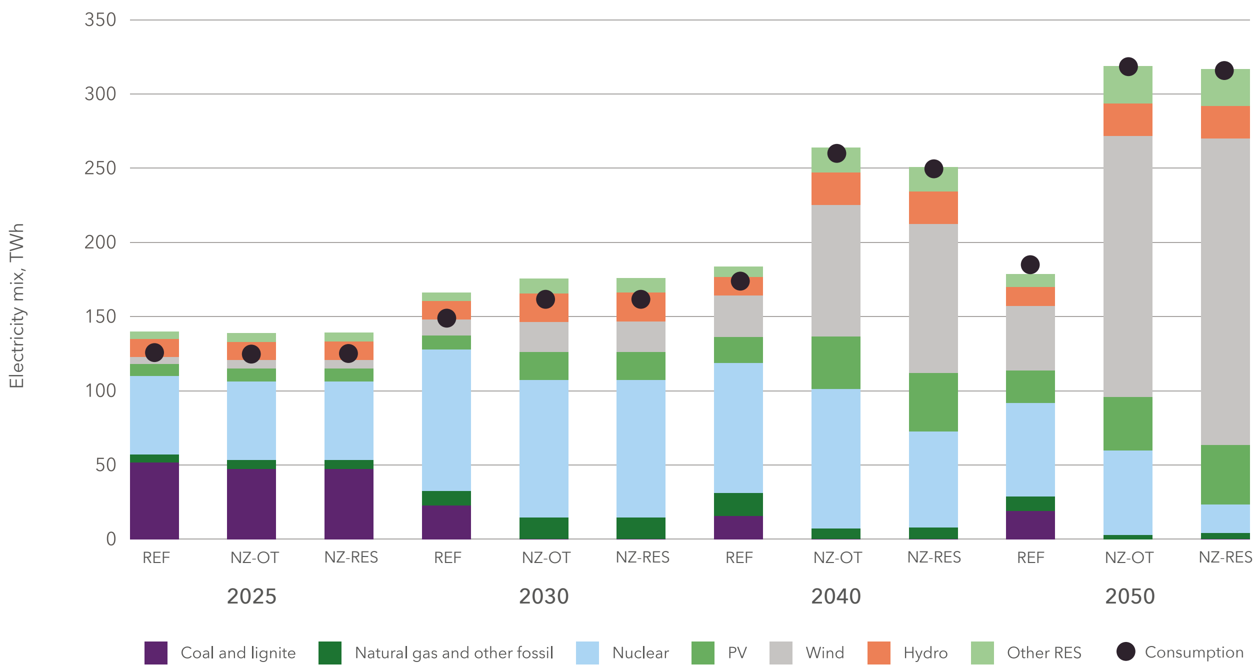
Electricity mix

The electricity generation mixes are very similar in 2025 across the scenarios. Coal generation remains a substantial but not dominant source in the Reference scenario until 2050. In the Net Zero scenarios coal gets phased out due to the introduction of the carbon price (ETS or equivalent).

Fossil gas has a stable low share in the reference scenario. In the Net Zero scenarios fossil gas becomes marginal by 2040 and disappears by 2050 when more nuclear capacity remains in the system (Net Zero-OT). Nuclear generation decreases in all scenarios but remains significant in all except the Net Zero-RES scenario where it is almost fully crowded out by renewables.

The most marked trend is the remarkable surge in renewable generation, especially wind towards the end of the period. Wind becomes the dominant source of electricity in the Net Zero scenarios from 2040 onward. The utilization of battery storage is twofold in the Net Zero scenarios compared to the Reference.

Figure 13: Electricity mix in the modelled scenarios

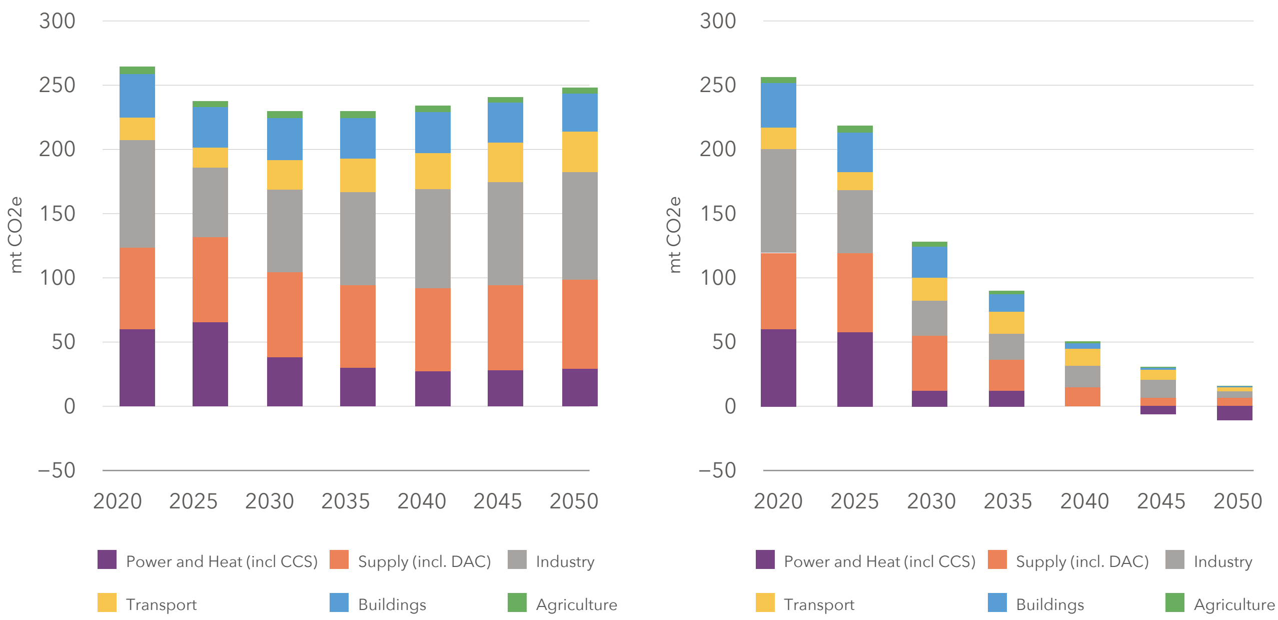


Source: EPMM

Carbon emissions

In the Reference scenario, emissions drop sharply from 2020 to 2025 then level out. Decreasing emissions from electricity and heat production, as nuclear and renewable sources replace coal power, are balanced by increasing emissions from the industry and transport sectors. In the Net Zero scenarios emission decline rapidly in all sectors.

Figure 14: Carbon emission in the Reference (left) and Net Zero (right) scenarios



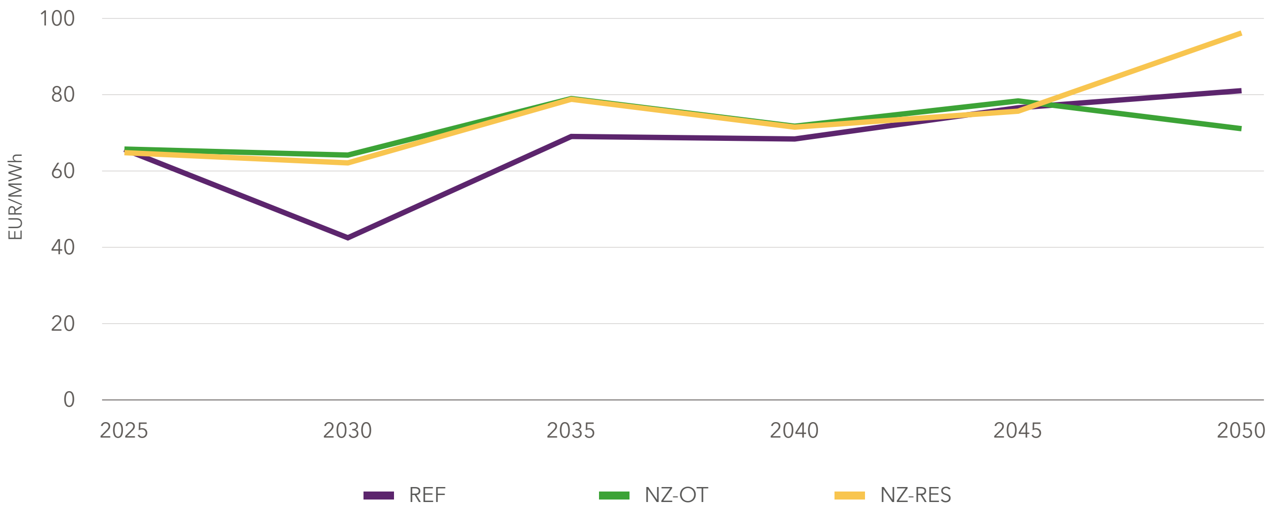
Source: TIMES-Ukraine

Power and Heat generation is the first sector that gets decarbonized in 2040 and becomes net negative due to carbon capture and storage (CCS) from 2045. **Negative emissions from the power sector balance small remaining emissions from the industry, transport and supply sectors, approaching net zero for the whole economy already in 2050**.

Wholesale electricity price

In 2025 wholesale electricity price in Ukraine is similar in all three scenarios. The approximately 65 €/MWh is significantly lower than in neighbouring countries as there is no carbon pricing in Ukraine, while it has high share of nuclear capacities with comparatively low marginal costs due to wear and tear. Between 2025 and 2030 the price is much lower in the Reference scenario because this is the only scenario without carbon pricing, and domestic capacities combined with import are sufficient to avoid high prices in most of the hours. The estimated drop in this period is a result of shrinking gas price. Consequently, in 2030, the prices in the Net Zero scenarios are approximately 20 €/MWh higher than in the Reference.

Figure 15: Evolution of baseload electricity price in three scenarios



Source: EPMM

Price convergence across the scenarios toward 2040 is due to contrasting trends in capacity dynamics. In the Reference scenario, available – predominantly - coal/lignite-based capacities diminish due to retirement. This decline in domestic electricity production results in higher prices during certain hours. In the Net Zero scenarios, on the other hand, a substantial increase in the share of renewable generation in total supply push average price down. As a result, by 2045, prices across all three scenarios converge at approximately 75 €/MWh.

By 2050 prices diverge again. The Net Zero – OT scenario produces the lowest price (~70 €/MWh) as nuclear and renewable capacities can meet the increasing demand in most hours, preventing the occurrence of high prices. The Reference scenario results in higher prices (~80 €/MWh) due to the lower share of renewable generation. The high price in the Net Zero-RES (~95 €/MWh) is due to the dominance of wind in the electricity mix. In low wind hours, domestic supply falls short, leading to exceptionally high prices and elevating the yearly average.

There are several policy options to mitigate this increasing price at the end of the period in the Net Zero-RES scenario. According to sensitivity analysis, the installation of an additional 9 GW solar PV capacity by 2050 would results in the same price as in the Net Zero-Open Technology scenario. Increasing cross-border transmission capacities by 1.5 GW or a 3.3% reduction in electricity consumption would bring prices to the level of the Net Zero-OT scenario. This is shown in the last column in the following table.

Table 3: Policy option to mitigate the post-2045 price increase at the Net Zero-RES scenario

Mitigating measures	Additional needs	Change from NZ-RES scenario values
PV capacity, GW	~9 GW	25.7%
Interconnection, GW	~1.5 GW	24.4%
Consumption	-	-3.3%

Source: EPMM

Detailed wholesale price data (per scenario and year) is provided in Annex 4: Wholesale price.

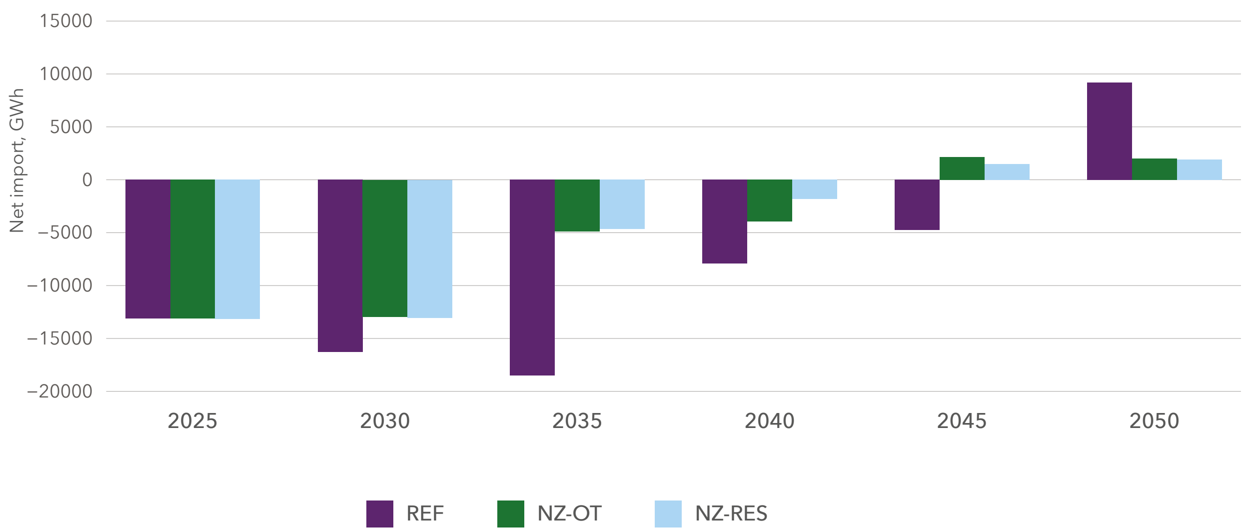
Cross border trade

The net trading position of Ukraine changes from exporter to importer in the modelled period. Ukraine has substantial exports in all scenarios until 2030 driven by the cost advantage of domestic generation in the absence of CO_2 pricing.

In the Net Zero scenarios, post-2030, exports to the EU declines due to the implementation of the ETS in Ukraine. Nevertheless, a net export position is maintained until 2040. Introducing the Carbon Border Adjustment Mechanism (CBAM) to the Reference scenario (Reference+CBAM) further influences the net export position, reducing it by approximately 7-13 TWh compared to the Reference scenario.

Towards the end of the period, Ukraine is likely to become predominantly an importer of electricity as the available generation capacities cannot fully meet the increasing demand resulting from widespread electrification efforts.

Figure 16: Net imports development, 2025-2050, GWh



Source: EPMM

The substantial price spread between Ukraine and the EU in the initial period results in high utilization in interconnectors for exporting. Utilization deteriorates after 2030 as price spread gets smaller. Towards the end of the modelled period, both utilization rate and congestion bounce back in the Net Zero scenarios in both trading directions. High variable wind production and a more tight supply during summer hours triggers more trade.

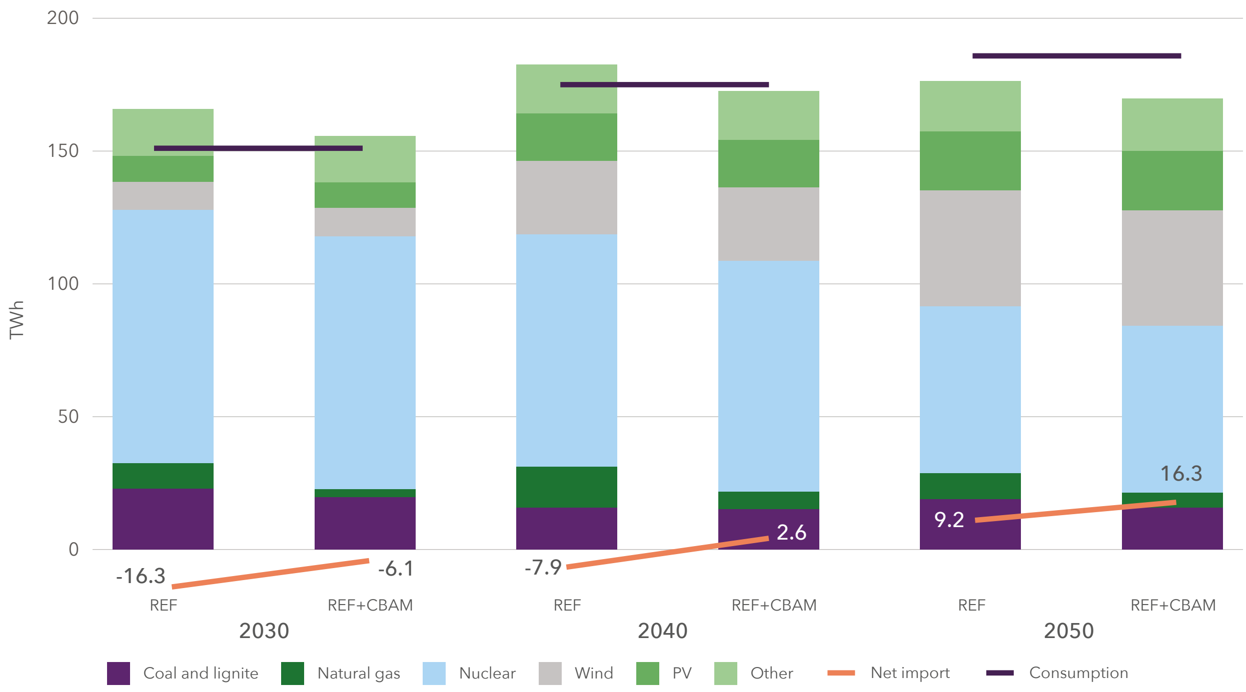
Table 4: Average hourly trade flows as a % of NTC (upper row) and the share of congested hours (lower row) for UA interconnectors

		REF				NZ-OT				NZ-RES			
Utilization, %													
		2025	2030	2040	2050	2025	2030	2040	2050	2025	2030	2040	2050
Export	HU	94,4%	97,8%	64,5%	45,9%	94,6%	85,6%	60,9%	52,0%	94,8%	85,7%	57,4%	50,2%
Export	MD	12,7%	90,1%	4,8%	33,2%	11,4%	81,3%	47,8%	46,3%	11,4%	82,0%	43,1%	43,9%
Export	PL	99,8%	100,0%	48,7%	20,2%	99,8%	87,9%	30,7%	30,8%	99,8%	88,2%	29,3%	33,6%
Export	RO	92,7%	97,0%	61,1%	46,1%	92,9%	82,9%	64,4%	53,2%	93,5%	83,6%	60,9%	51,3%
Export	SK	94,2%	97,2%	31,8%	20,3%	94,3%	76,5%	19,5%	30,6%	94,5%	76,7%	20,0%	33,1%
Import	HU	4,2%	1,8%	7,8%	47,0%	4,0%	7,3%	8,0%	44,0%	3,9%	6,9%	10,2%	44,9%
Import	MD	48,7%	3,9%	77,7%	43,9%	49,8%	8,8%	10,8%	37,5%	49,4%	8,8%	13,5%	38,3%
Import	PL	0,0%	0,0%	35,7%	71,5%	0,0%	7,0%	56,7%	57,1%	0,0%	6,9%	60,6%	57,6%
Import	RO	5,0%	1,6%	14,2%	41,1%	4,8%	7,9%	11,8%	38,6%	4,5%	7,5%	14,7%	39,1%
Import	SK	4,2%	1,9%	36,2%	66,4%	4,1%	13,0%	56,6%	55,2%	3,9%	12,6%	60,2%	54,7%
Share of congested hours, %													
		2025	2030	2040	2050	2025	2030	2040	2050	2025	2030	2040	2050
Export	HU	93,3%	96,9%	48,0%	28,4%	93,6%	77,4%	37,9%	38,4%	93,5%	77,9%	31,1%	36,7%
Export	MD	11,2%	87,5%	1,5%	23,6%	10,2%	75,9%	36,9%	37,6%	10,2%	77,4%	27,6%	36,0%
Export	PL	99,4%	99,8%	34,8%	14,7%	99,4%	82,6%	22,9%	18,5%	99,5%	82,3%	23,2%	25,5%
Export	RO	90,9%	95,4%	44,2%	27,9%	91,3%	76,1%	38,5%	38,5%	92,1%	77,7%	31,2%	37,8%
Export	SK	93,2%	96,2%	16,6%	12,4%	93,5%	70,5%	8,6%	17,2%	93,3%	71,4%	9,7%	23,1%
Import	HU	3,3%	1,4%	1,7%	36,2%	3,2%	3,5%	2,3%	33,4%	3,2%	3,6%	3,1%	34,3%
Import	MD	17,8%	1,0%	57,8%	33,4%	17,6%	3,7%	2,2%	31,0%	17,3%	3,4%	2,8%	31,2%
Import	PL	0,0%	0,0%	22,8%	60,7%	0,0%	4,4%	44,1%	45,2%	0,0%	4,6%	51,0%	47,2%
Import	RO	4,2%	1,0%	2,5%	34,0%	4,1%	3,7%	2,3%	31,5%	3,9%	3,4%	3,2%	32,1%
Import	SK	3,3%	1,4%	15,4%	54,3%	3,2%	7,6%	38,5%	42,7%	3,2%	7,5%	45,1%	44,4%

CBAM scenario results

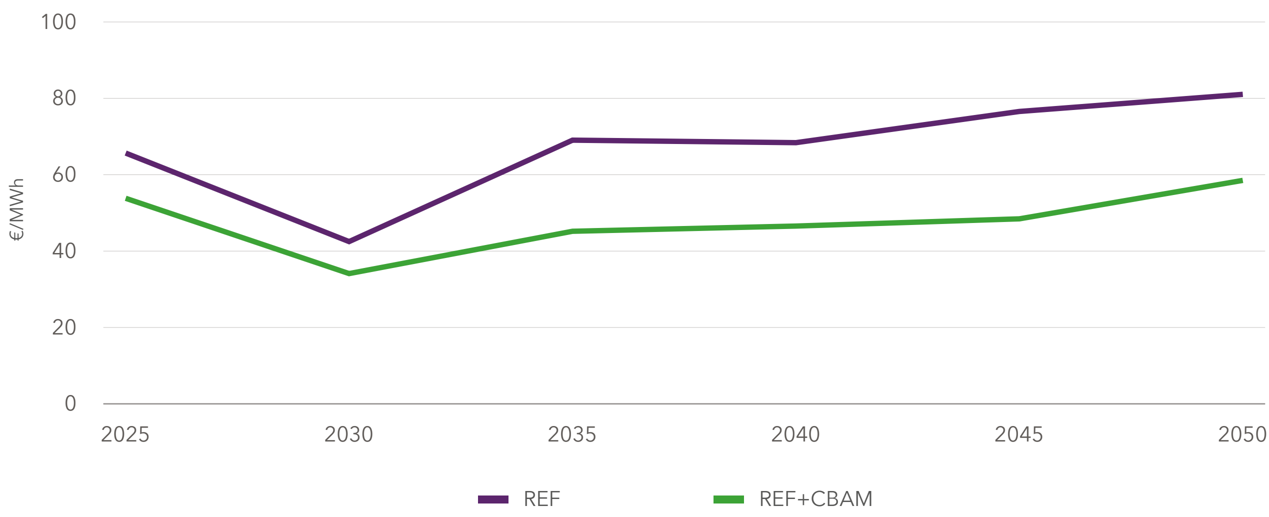
We modelled the impact of introducing CBAM on the Ukrainian electricity sector as a variation of the Reference scenario as in the Net Zero scenarios Ukraine is assumed to have EU ETS or equivalent and hence the CBAM is not applicable. CBAM is a carbon border tax introduced by the EU to create a level playing field for products created in the EU or imported from countries with no or less carbon tax. The CBAM is applicable for high emitting industrial sectors and electricity and will be fully implemented from 2026. This means that electricity exports from Ukraine to the EU will be taxed at the border. This effectively reduces exports, as in those hours, when the tax is higher than the price spread, no exports will take place to EU countries. Once CBAM is implemented, the relatively cheap electricity will get consumed domestically instead of being exported to the EU. This substitution lowers domestic wholesale electricity price in Ukraine while increasing price spread between Ukraine and the EU. CBAM has serious negative impacts on power generators and traders as they lose export revenues. It, however, does not impact the merit order and hence does not trigger the decarbonization of the power sector like ETS (or an equivalent carbon tax) does. It is also important to note, that other exporting sectors in Ukraine's economy – which is not modelled by EPMM – will also lose export revenues due to worse competitive position in goods trade.

Figure 17: Electricity generation mix in the Reference and Reference+CBAM scenarios, TWh



Source: EPMM modelling

Figure 18: Wholesale electricity price development in Ukraine in the Reference and Reference+CBAM scenarios, €/MWh



Source: EPMM modelling

Energy system cost

The minimization of discounted total energy system costs (the objective function of the TIMES-Ukraine model) is the main criterion upon which the trajectory of the energy system development is evaluated. It serves as the important metrics when comparing different scenarios. Total energy system cost has a wide coverage: it includes the CAPEX and OPEX of all assets associated with the energy system, including generation, energy transport and energy use equipment.[13]

Table 5: System cost estimates by the TIMES-Ukraine model

	Reference Scenario	NZ-OT Scenario		NZ-RES Scenario	
	Bln Euro	Bln Euro	Difference (%)	Bln Euro	Difference (%)
Total energy system costs (discounted)	1 733.1	1 784.0	2.9%	1 785.8	3.0%
Total capital costs for 2025-2050 (non discounted)	623.2	940.4	50.9%	942.2	51.2%
Capital costs in power generation sector for 2025-2050 (non discounted)	96.1	201.5	109.7%	191.0	98.8%
Total O&M Costs for 2025-2050 (non discounted)	431.8	481.9	11.6%	485.9	12.5%
Total Fuel Costs, incl. revenues from exogenous export for 2025-2050 (non discounted)	368.4	213.6	-42.0%	210.9	-42.8%

Source: TIMES-Ukraine Model

Therefore, capital investments, considered in TIMES-Ukraine, are not just investments in the energy sector but are «energy related investments» accounting for about 60-70% of total investments in the economy. Thus, investments in the power generation sector make just 15-25% of the overall investments assessed by the model, while the rest capital expenditures should be directed to other sectors such as Industry, Transport and Buildings.

13 Total energy system costs include:
- capital investments (costs) both for the construction of new energy assets and for the purchase of final energy consumption appliances, some of which could be considered as not investment, but intermediate production or final consumer costs (for energy management, installation of modern control systems, thermal modernization of buildings, purchase of household appliances or vehicles, etc.);
- fixed and variable operating and maintenance costs for energy production, transportation and consumption technologies;
- energy and fuel costs (expenditures) assessed on the basis of the marginal cost of each type of fuel, taking into account the cost of imported resources;
- concessions, rental or other payments (target allowances, emission tax, etc.);
- residual value of technologies at the end of the modelling horizon.

Total capital costs in the Net Zero scenarios are roughly 51% higher than in the Reference scenario and ranges between 30 and 40 billion Euro/year. Major investments include electric and other clean-fuelled vehicles, upgrades to buildings, installation of clean heating systems, and new renewable and nuclear power plants, although nuclear investment only takes place in the NZ-OT scenario.

Investments for clean heating, power, and CHP plants double in Net Zero scenarios comparing to the Reference case and costs about 6.5 billion Euro/year.

Although upfront investment need in the Net Zero scenarios is higher than in the Reference, total system costs are only 3% higher as fuel cost savings over equipment lifetimes substantially offset the greater upfront capital costs. An additional benefit of fuel savings in the Net Zero scenarios would be improved energy security in Ukraine as a considerable part of fuels relates to imports.

DECARBONISING THE POWER SECTOR OF UKRAINE: CONCLUSIONS AND RECOMMENDATIONS

Long-term vision

A comprehensive and forward-looking long-term vision embedded in a strategic document adopted by the government is the cornerstone of successful decarbonisation.[14] Ukraine should develop a clear roadmap that aligns with EU climate goals, outlining explicit targets and milestones. This includes a phased transition plan that takes into account technological advancements, market dynamics, and evolving regulatory landscapes. By providing a long-term perspective, the government can enable a stable and predictable environment for investors, fostering confidence and commitment to the decarbonisation journey.

The 2030 implementation of the EU carbon pricing scheme, as assumed in the Net Zero scenarios, serves as a key catalyst of energy transition. This would provide a credible framework for decarbonisation, leading to the accelerated adoption of renewables and the phase-out of coal-based generation. In order to take part in the EU carbon pricing scheme, Ukraine needs to speed up the preparation of institutions and processes. A smooth transition could involve the gradual increase of the current national carbon tax. Ukraine adopted a 65% reduction target in greenhouse gas (GHG) emissions for 2030, which will be revised once martial law is no longer in effect.[15]

The introduction of ETS would make the Carbon Border Adjustment Mechanism (CBAM) – to be implemented on all third countries to the EU from 2026 – irrelevant for Ukraine. Whereas ETS revenues would be retained within Ukraine, the revenues from the border tax are, by default, kept by the EU. This would reduce Ukraine's competitive position, as the country would be able to export 30-50% less electricity compared to the reference case. CBAM does not trigger decarbonisation until there is enough domestic demand to consume the electricity previously exported.

14 Link for the 2050 Energy Strategy of Ukraine. (not publicly available) https://zakon.rada.gov.ua/laws/show/373-2023-%D1%80#Text

15 The Clean Energy Package targets - Energy Community Homepage (energy-community.org) www.energy-community.org/implementation/package/CEP.html

Principles of energy transition

Transparency

Transparency is vital in building public trust and attracting private investment. Establishing clear mechanisms for policy formulation, decision-making, and implementation helps stakeholders understand the rationale behind regulations. Regular reporting on progress, challenges, and adjustments enhances transparency. In addition, creating platforms for stakeholders to access relevant information and contribute to the decision-making process ensures inclusivity. Conversely, a lack of transparency can lead to suspicion and resistance, potentially jeopardising the success of decarbonisation efforts. Therefore, the Ukrainian government should prioritize transparent communication channels and mechanisms to maintain a strong connection with the public and investors alike.

Public Participation

Public participation is not just a procedural requirement but a strategic imperative. By actively involving citizens, non-governmental organisations (NGOs), and businesses in the decision-making process, Ukraine can harness collective intelligence, identify potential roadblocks, and ensure wider social acceptance of policies. Learning from successful cases globally, the government should leverage technology to facilitate public input, making the engagement process accessible and inclusive. Ignoring public opinion may lead to social resistance, legal challenges, and delays in project implementation. Therefore, public participation should be embedded in the regulatory framework to foster a sense of ownership and shared responsibility for the energy transition.

Communication

Effective communication is paramount for garnering public support and investor confidence. The Ukrainian government should develop clear, consistent, and accessible messaging that educates the public about the benefits of decarbonisation and the risks of inaction. Regular updates on progress and milestones help maintain momentum and build a positive narrative around the transition. Lessons from successful communication strategies globally emphasize the need for engaging multiple channels, including social media, traditional media, and community outreach programs. Failure to communicate effectively may result in misconceptions, misinformation, and a lack of public support, undermining the broader goal of a sustainable energy transition. Therefore, robust communication strategies should be a central component of Ukraine's regulatory framework.

Equity

Ensuring equity in the distribution of costs and benefits and burdens is a fundamental consideration in the decarbonisation process. Policymakers must prioritize policies that prevent vulnerable populations from disproportionately bearing the costs of the transition. This could involve targeted subsidies for low-income households, job transition programs for workers in declining industries, and inclusive financing mechanisms. By conducting thorough impact assessments, the government can identify potential disparities and proactively address them in the policy design phase. Conversely, neglecting equity considerations may result in social unrest, resistance to policy implementation, and a fractured societal approach to decarbonisation.

Strong institutions

The development and strengthening of robust institutions – competition watchdog, energy regulatory office, consumer protection office – are critical to reducing the country risk premium and attracting private investment. Establishing agencies with the capacity to oversee and enforce regulations ensures a level playing field for all market participants. Additionally, these institutions should have the flexibility to adapt to evolving market conditions and technological advancements. Ukraine should prioritize capacity building within regulatory bodies and invest in the necessary skills to support effective oversight. Weak institutions may lead to regulatory uncertainty, delays, and increased perceived risks for investors.

Infrastructure

Power sector transition means, on the one hand, the large-scale buildout of new, carbon-free generation assets, and transmission and distribution grids on the other. These assets are characterised by large upfront and low variable costs. The sheer volume of the required investment means that public resources must be accompanied by private money. Therefore, lowering the currently high cost of capital in Ukraine is a key factor to reduce the overall investment cost.[16]

Substituting fossils with carbon-free generation is achievable before 2050 by the scaling up of renewables, even without new nuclear facilities (Net Zero-RES scenario). With the reintegration of the Zaporizhzhya NPP, the existing nuclear fleet, however, helps to decarbonise the sector. For new nuclear to be built, strong investment cost reduction (5250 €/kW in the Net Zero-OT scenario) would be needed when compared to current levels.[17]

Ukraine has vast solar and wind potential. This study forecasts particularly strong uptake of wind. Integrating wind in the vast territory of Ukraine would reduce generation volatility due the portfolio effect. The optimal renewable technology portfolio, however, is sensitive to cost developments and network availability.

To accelerate large-scale renewable energy projects, Ukraine should streamline permitting processes, reducing bureaucratic hurdles regarding network connection. Additionally, investing in grid infrastructure and storage facilities is crucial to handling the intermittent nature of renewable sources.

One specific recommendation is to implement a cost-efficient and market-driven support mechanism such as a two-sided Contract for Difference (CfD) system. This would provide investors

16 Irena (2023) The cost of financing for renewable power (irena.org), www.irena.org/publications/2023/May/The-cost-of-financing-for-renewable-power

17 L. Göke - A. Wimmers - C. v. Hirschhausen: Economics of nuclear power in decarbonized energy systems (2023); https://arxiv.org/abs/2302.14515

with a predictable revenue stream and enhance competition while protecting consumers from unnecessary costs. Careful consideration will need to be given to auction and contract design as well as setting correct ceiling prices and providing long-term visibility over auction schedules.

Coal can be phased out completely by 2035 without endangering resource adequacy of the power system. According to the modelling, only 850 MW coal power plants remain in the system by 2030 in both Net Zero scenarios.

To be able to benefit from the integration of Ukraine to ENTSO-E and trade and balance renewable electricity in a wider geographical market, there is a need for considerable cross border capacities (CBCs). The utilisation rates of CBCs are high throughout the modelling period, indicating that CBCs are important elements of the Ukraine's power system. They help the system in peak demand hours and increase system flexibility. One option to mitigate the high price of the Net Zero-RES scenario at the end of the period is to build capacities additional to the ones already planned and reported in the TYNDP; the modelling results indicate that an additional 1.5 GW of CBC capacity would have a price reducing effect of 25 €/MWh (see Table 3 for details). The buildout of planned cross-border capacities should get priority in the future transformation of Ukraine's power system.

Flexibility

An electricity system based on large amounts of renewables requires a lot of flexibility. It is important to recognize all possible contributors (supply side, demand side, storage, interconnectors) and prioritize those with speediest implementation times and best cost-benefit ratio. Enhancing system flexibility also requires significant investments in smart grid technologies and demand response systems. Additionally, incentivizing the adoption of energy storage technologies, such as batteries, will contribute to system flexibility.

The power system remains balanced in all scenarios throughout all years, meeting reserve requirements even when dispatchable generation is substituted with variable technologies. In all cases, the modelling assumes the increase of mobilisable flexible load capacity, from 8% (of average weekly load) in 2020 to 25% in 2050. Flexibility in the upward direction is supplied through hydro and battery storage and with demand-side resources. In the downward direction, coal is substituted by gas and, to a much larger extent, by renewables from 2030 onwards in the Net Zero scenarios. The role of gas in the Net Zero scenarios is even more limited, accounting for less than 8% in 2030 and only 2% of electricity production in 2050. This underscores a gradual shift towards cleaner and more sustainable energy sources, minimising reliance on gas as the transition progresses.

Demand

Decarbonisation of the economy requires massive electrification and sector coupling. Despite power demand more than doubling between 2025 and 2050 in the Net Zero scenarios, the modelled systems effectively satisfy the increased need. This demonstrates the adaptability and robustness of the decarbonization approach.

Prosumers are key actors in the transition. They reduce the volume of electricity supply from the grid and, hence, the need for power transport infrastructure. In combination with PV and small-scale batteries, prosumers could provide flexibility, especially when organized by aggregators. Encouraging prosumer participation requires simplifying bureaucratic procedures and introducing financial incentives (also by efficient price discovery on the wholesale and retail markets) while not putting a strain on the functioning of the system. A robust regulatory framework might include net billing or buy-all, sell-all schemes that address concerns related to flexible demand.

Moreover, fostering community-based energy projects through cooperative models can empower local communities. The government can incentivise such projects through targeted subsidies or tax breaks, fostering a sense of ownership and sustainability. The implementation of several pilot energy community projects across Ukraine is recommended to work out an optimal approach for supporting them and integrating to the energy market.

Improving energy efficiency is still one of the main drivers of emissions reductions, in addition to shifting generation to renewables. Rebuilding Ukraine should incorporate the optimal mix of these main decarbonisation options. Ukraine should consider adopting and enforcing updated building codes that prioritize energy efficiency. A concrete recommendation is to implement financial incentives, such as tax credits or subsidies, for businesses and households adopting energy-efficient technologies. Reconstruction should keep in mind that investment into fossil infrastructure, including gas transmission and distribution grids, but also gas boilers, runs the risk of creating stranded assets.

Furthermore, the government should invest in public awareness campaigns to educate citizens on the importance and available options of energy conservation. Building a culture of energy efficiency requires a coordinated effort involving educational institutions, media, and local communities.

Cost of transition

The total energy system cost in the Net Zero scenarios, including of all energy generation, transport and use assets, is similar to the Reference scenario. **This means that the energy transition is not significantly more expensive for the society on the long run.** The energy transition requires a high amount of capital investment, especially in the beginning of the modelled period. The modelled investments include not only large-scale assets but electric vehicles (EVs), heat pumps and more efficient domestic appliances purchased by households. The power sector investments to double in the Net-Zero scenarios compared to the Reference to serve the twofold increase in demand due to electrification. **The large investment cost is balanced by the relatively modest running cost of a decarbonised energy system, with all the associated benefits such as improved security of supply, trade balance and environmental gains.**

The need to mobilise private capital is a recurring theme in both planning the transition and implementing the necessary regulatory environment. Private investors, both foreign and domestic, will need to be assured that their investment is protected, and the prospective returns are proportionate to the risks involved. Therefore, the biggest regulatory priority would be to lower investor risk and provide a stable and predictable investment climate, firmly showing the pathway to full implementation of EU law. Due to the war, the so-called country risk will remain elevated for some time, at least until Ukraine becomes a full member of the EU. It is all the more important, therefore, to strive to reduce the risk that remains under full government control, which is the regulatory risk.

While wholesale prices are initially 15-20 €/MWh higher (until 2035) in the Net Zero scenarios, they later stabilize and converge with the Reference scenario prices due to the price reducing effect of renewables (merit order effect). This suggests that any temporary price increase during the early stages of decarbonisation is mitigated over time, resulting in a cost-effective and sustainable energy transition.

Final consumers make their choice based on retail prices, which should reflect scarcity or price at the wholesale market. The majority of final consumers, however, cannot be exposed to the price risk prevalent at the wholesale level. Consumers should have a choice of tariff offers which suit his or her risk appetite, level of consumption and flexibility potential.

Annex 1:

Assumptions on net transfer capacities (NTCs)

The following table shows the NTCs used in the modelling.

Table 6: NTCs at the borders of Ukraine

Net transfer capacity, MW							
		2025	**2030**	**2035**	**2040**	**2045**	**2050**
Export	**HU**	429	429	650	650	650	650
	MD	264	264	400	400	400	400
	PL	799	799	1 210	1 210	1 210	1 210
	RO	198	264	1400	1400	1400	1400
	SK	264	264	1400	1400	1400	1400
Import	**HU**	297	429	650	650	650	650
	MD	264	264	400	400	400	400
	PL	666	666	1 000	1 000	1 000	1 000
	RO	99	264	1400	1400	1400	1400
	SK	264	264	1400	1400	1400	1400

Source: National Council for the Restoration of Ukraine (2022)[18] and REKK's assumptions

18 https://www.kmu.gov.ua/storage/app/sites/1/recoveryrada/ua/energy-security.pdf

Annex 2:

Generation capacity assumptions of the TIMES-Ukraine model

Nuclear power plants

The lifetime of existing nuclear power plants (NPPs) gets extended as declared by EnergoAtom. The damaged Zaporizhzhya NPP is expected to return to operations between 2025 and 2030. Future nuclear generation capacity is capped in the Times-Ukraine model as defined by the Ministry of Energy[19] at 18 GW new large units (in all scenarios) and 40*160 MW Small Modular Reactor (SMR) units (in Net Zero scenarios).

Reference Scenario	Net Zero Scenario(s)
No Small Modular Reactor (SMR) technology is available	All nuclear technologies are available
CAPEX: Large units = 5250 €/kW;	CAPEX: SMR & Large units = 5250 €/kW in Net Zero-OT scenario, 7000 €/kW in Net Zero-RES scenario *[Source: IEA, Nuclear Power]*
AF: SMR = 90%, Large units = 88%	

Fossil-based thermal and combined heat and power plants

As there is no stringent political decision on coal phase-out, the future use of coal is estimated by the TIMES-Ukraine model endogenously. The model has several options how to treat with existing thermal generation capacities, both captured by the Russian Federation at the moment and those located on controlled area. Capacities captured by the Russian Federation could be: 1a) phased-out if reconstruction is economically unfeasible and electricity demand is sufficiently met by other capacities; 1b) re-integrated after the war that assumes rehabilitation costs. These reintegrated facilities together with other existing TPPs/CHPs would operate under 2a) actual or 2b) improved technical conditions involving additional modernization costs by the year specified in the NERP (National Emission Reduction Plan). After the specified time these plants should be 3a) phased out or 3b) refurbished to meet the requirements of the Industrial Emissions Directive.

Reference Scenario	Net Zero Scenarios
No switch to bio- or synthetic methane	Gas TPPs and CHPs can be switched to bio- or synthetic methane after 2030

19 https://ua-energy.org/uk/posts/yaroslav-demchenkov-postupovo-do-2035-roku-realno-vidmovytysia-vid-vuhillia

Bioenergy-based thermal and combined heat and power plants

The Bioenergy Association of Ukraine reports the bioenergy potential of 48 million tons of oil equivalent (toe) by 2050.[20] This includes biogas and maximizing the use of energy crops, wood and agricultural residues. Long-term supply contracts and technical solutions for utilities will be key to harnessing this clean energy resource. Bioenergy power plants and CHPs in the TIMES-Ukraine model can use wide range of solid and gaseous fuels, including agricultural residues, wood chips and pellets, bioenergy crops, municipal and industrial waste, biogas and biomethane. This latter fuel can also substitute natural gas in existing or new gas-fired TPPs and CHPs.

Reference Scenario	Net Zero Scenarios
Capacity cap of TIMES-Ukraine, GW: Bio TPPs: 2030 – 0.27, 2040 – 0.32, 2050 – 0.4; Bio CHPs: 2030 – 0.24, 2040 –0.466, 2050 – 0.967; BioCCS unavailable	Capacity cap of TIMES-Ukraine, GW: Bio TPPs: 2030 – 0.46, 2040 – 0.63, 2050 – 0.89; Bio CHPs: 2030 – 0.61, 2040 – 2.33, 2050 – 4.84; Bioenergy CHPs and TPPs with CCS allowed to produce negative emissions

20 https://uabio.org/wp-content/uploads/2020/11/uabio-position-paper-26-en.pdf; https://uabio.org/wp-content/uploads/2021/08/Prospects-for-Bioenergy.pdf

Wind power plants

Wind generation is represented with various categories for onshore and offshore power plants with different investments, O&M costs and potential.

Reference Scenario	Net Zero Scenarios
Capacity cap of TIMES-Ukraine, GW: Onshore: 2030 – 3.1, 2040 – 6.4, 2050 – 9.1; Offshore: 2030 – 0.5, 2040 – 3, 2050 – 5	Capacity cap of TIMES-Ukraine, GW: Onshore: 2030 – 7.1, 2040 – 22.1, 2050 – 43.1; [Source: UWEA] Offshore: 2030 – 4, 2040 – 25, 2050 – 45 *[Source: UWEA; O.Diachuk et al.]*[21]

Solar PV power plants

Utility-scale solar technology is represented with 3 untracked and 3 tracked unit type. They have different investments, O&M costs and potential. They have increasing connection and integration costs in the later periods.

Reference Scenario	Net Zero Scenario(s)
Capacity cap of TIMES-Ukraine, GW: Utility-scale: 2030 – 8.1, 2040 – 13.1, 2050 – 18.1; Rooftop: 2030 – 3.3, 2040 – 6.5, 2050 – 10	Capacity cap of TIMES-Ukraine, GW: Utility-scale: 2030 – 13.1, 2040 – 29.9, 2050 – 60; Rooftop: 2030 – 6.3, 2040 – 16.3, 2050 – 24 *[Source: O.Diachuk et al., expert consultations]*

21 See: https://ua.boell.org/sites/default/files/transition_of_ukraine_to_the_renewable_energy_by_2050_1.pdf

Hydro power plants

Large hydropower development is capped in the model reflecting nature conservation concerns. Consequently, only the completion of selected planned power plants is considered according to the plans of UKRENERGO. Existing small hydropower plants have raised environmental concerns in the past. However, experience in Austria and Norway show the potential for responsible development. The model assumes that new small units will meet the most stringent environmental criteria.

Reference Scenario	Net Zero Scenarios
Capacity cap of TIMES-Ukraine, GW: Large: 6.3; Small: 2030 – 0.256, 2050 – 0.376	Capacity cap of TIMES-Ukraine, GW: Large: 2030 – 8.6, 2040 – 9.9, 2050 – 10.4, Small: 2030 – 0.256, 2050 – 0.376

Other key assumptions

Reference Scenario	Net Zero Scenario(s)
Carbon Capture	
Unavailable	CCS available to coal, gas and biomass power plants and CHPs, industrial technologies, as direct air capture
Carbon tax	
Current low level of carbon tax is kept	EU proposed carbon price pathway for the power sector (2025-30: No ETS price, 2030: 80 €/tCO2, 2040: 85 €/tCO2, 2050: 160 €/tCO2) [Source: EC Impact Assessment 2021]; No price set for other sectors; marginal price estimated by the model upon emission constrain

Reference Scenario	Net Zero Scenario(s)
CBAM	
Not applied in order to have the scenario more comparable to the Net Zero scenarios, to clearly show the difference of the EU ETS pricing. A sensitivity case is analysed on the power sector impacts of CBAM.	Not applied as Ukraine applies ETS or equivalent. [Source: EC, 2023]
Decarbonisation target	
None	Decarbonization of the power sector by 2050 and overall carbon neutrality by 2060 according to the concave pathway set exogenously, kt CO_2eq: 2025 – 170086 2030 – 120000 2035 – 80000 2040 – 50000 2045 – 30000 2050 – 15000 2055 – 5000 2060 – 0

Annex 3:

Technologies used in the TIMES-Ukraine model and their key parameters

Technologies	*Overnight Capital Cost (CAPEX), €/ kWe*							*Efficiency (Electric), %*	*Capacity factor[22], %*	*Life-time, years*	*Heat Rate*
	2020	2025	2030	2035	2040	2045	2050				
Thermal Power Plants (TPPs) and Combined Heat and Power Plants (CHP)											
Nuclear											
New Large Units	5250/7000							33	88	60	0.03
Extension of the operational life of existing units of NPPs	254							33	80	30	0.04
New small nuclear reactors (160 MW)	5250/7000							32	90	80	0.04
Nuclear Very High Temperature reactor with Hydrogen production	7650-6885							33	94	60	0.1-0.12 (H2)
Gas											
Combined cycle TPPs	1000							60	50	35	0.15
Combustion turbine TPPs	600							40	50	30	0.15
Steam turbine TPPs	920							42	50	30	0.15
Fast Start Engine TPPs (only as balancing technologies)	1000							50	1.5	35	-
Combined Cycle + Carbon Capture and Storage TPPs	2450							51	50	35	0.05
Combustion turbine + Carbon Capture and Storage TPPs	2050							34	50	30	0.05
Combined cycle CHPs	800							50	50	35	0.84
Combustion turbine CHPs	920							45	50	35	0.95
Extension of the operational life of existing CHPs	280-650							19-43	50	15	1.1-3.0
Combined Cycle + Carbon Capture and Storage CHPs	2250							45	50	35	0.84
Coal											
Integrated gasification combined cycle (IGCC) TPPs	1800							46	50	35	0.15
Supercritical parameters TPPs	1300							43	50	40	0.15
Subcritical parameters TPPs	1600							39	50	35	0.15
Circulating Fluidized Bed TPPs	1700							43	50	35	0.15
Joint combustion of coal and biomass (subcritical parameters) TPPs	2050							33	50	35	0.15
Extension of the operational life of existing Coal TPPs	950							33-40	34-62	20	0.01-0.19
IGCC + Carbon Capture and Storage TPPs	4400							39	50	35	0.15
Supercritical + Carbon Capture and Storage TPPs	3900							37	50	35	0.15
Subcritical + Carbon Capture and Storage TPPs	4650							33	50	35	0.15
Circulating Fluidized Bed + Carbon Capture and Storage TPPs	4300							28	50	35	0.15
Combined cycle CHPs	1200							40	50	35	0.84
Combustion turbine CHPs	1100							35	50	35	0.90
Combined cycle+ Carbon Capture and Storage CHPs	2650							35	50	35	0.84
Bioenergy											
Wood biomass TPPs	2800	2750	2700	2650	2600	2550	2500	24	50	30	-
Biomass from waste TPPs	2900	2850	2800	2750	2700	2650	2600	23	50	30	0.3
Biogas TPPs	3200	3200	3200	3200	3200	3200	3200	42	50	30	-
Energy crops TPPs	2900	2850	2800	2750	2700	2650	2600	24	50	30	-
Wood biomass+ Carbon Capture and Storage TPPs	3650							24	50	30	-
Biogas + Carbon Capture and Storage TPPs	5350							42	50	30	-
Energy crops + Carbon Capture and Storage TPPs	3750							24	50	30	-
Wood biomass CHPs	3400	2850	2800	2750	2700	2650	2600	20	50	35	2.0
Biomass from industrial waste CHPs	3400	2950	2850	2850	2900	2750	2700	19	50	35	1.9
Biomass from municipal waste CHPs	5400	2950	2900	2850	2800	2750	2700	25	50	35	1.2
Energy crops CHPs	3400	3150	3100	3050	3000	2950	2900	20	50	35	2.0
Wood biomass + Carbon Capture and Storage CHPs	4450							20	50	35	1.5
Energy crops+ Carbon Capture and Storage CHPs	4450							20	50	35	1.5
Wind											
Onshore Wind Power Plants	1100	1075	1050	1000	950	900	850	-	32	30	-
Offshore Wind Power Plants	2120	1960	1800	1700	1680	1660	1640	-	42	30	-
Solar											
PV Plant size (without tracker)	750	725	700	630	560	510	475	-	12.5	25	-
PV Plant size (with tracker)	920	850	800	720	645	590	540	-	14.7	25	-

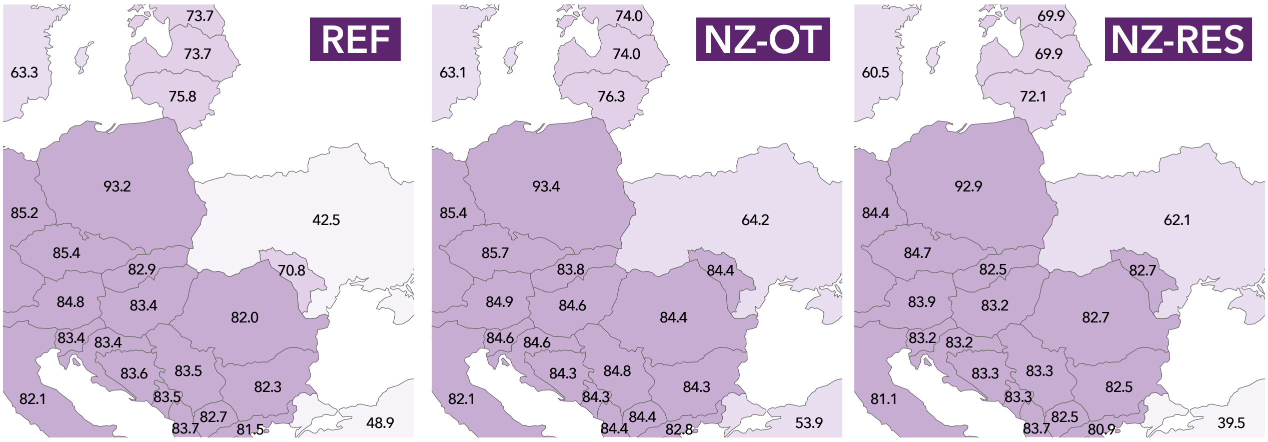
22 Due to limitations of the TIMES-Ukraine modelling, capacity factor means the highest expected annual utilization factor due to technical availability and competitiveness in dispatch. Actual model utilization rate could be lower.

PV Roof panel	900	875	850	800	750	700	600	–	13.5	25	–
Geothermal											
Geothermal Power Plants	4300-3600							–	35-55	25	–
Hydro											
Small Hydro Power Plants	3250-3080							–	30	40	–
Large Hydro Power Plants	3300-3100							–	33-36	60	
Pump Storage	610							80	27	60	–
Storage technologies, €/kWh											
Electric Battery Storages	1042	832	622	508	394	324	255	92	33	10	–
Hydrogen Underground Storage Large	980	750	700	650	600	550	500	100	100	30	–
Hydrogen Tank Storage Large	4600	3600	3400	3200	3000	2800	2500	100	100	22	–
Hydrogen Tank Storage Small	2650	2075	1900	1800	1700	1600	1500	100	100	22	
Seasonal Heat Storage	2700	2600	2562	2434	2312	2197	2087	70	50	20	–
Fuel Cells (Hydrogen)											
Fuel Cells Power Plants	2530	1125	1125	844				50	85	10	–
Fuel Cells Combined Heat and Power Plants	2530	1125	1125	844				50	60	10	0.64
Heat plants											
Hard Coal District Heating Plant	600							40	50	35	–
Anthracite District Heating Plant	600							40	50	35	–
Lignite District Heating Plant	700							40	50	35	–
Gas District Heating Plant (with availability of bio or synthetic methane)	300							71	50	40	–
Wood biomass District Heating Plant	145	142	140	138	136			64	50	35	–
Biomass from industrial waste District Heating Plant	350	320	300	280	270	260	250	62	50	35	–
Electric District Heating Plant	350							90	50	40	–
Air-sourced Heat Pump District Heating Plant	1100							250	50	25	–
Hydrogen District Heating Plant	390							64	50	35	–
Generic boilers											
Gas/Coal Generic industrial boiler plant (bio&synthetic methane ava-le)	59	59	58	58	57	56	56	90	60	40	–
Wood biomass Generic industrial boiler plant	145	142	140	138	136	134	134	83	60	40	–
Biomass from Industrial Waste Generic industrial boiler plant	270	260	250	240	230	220	220	80	60	40	–
Hydrogen Generic industrial boiler plant	145	142	140	138	136	134	134	81	60	35	–
CHP autoproduction											
Hard Coal CHP autoproduction	3600							3-15	15	35	2.7-18
Gas CHP autoproduction (with availability of bio or synthetic methane)	1080							3-15	15	35	4.4-20
Coke Oven Gas CHP autoproduction	1080							3-15	15	35	3.3-26.7
Blast Furnace Gas CHP autoproduction	1080							3-15	15	35	3.3-21
Heavy fuel oil CHP autoproduction	1080							3-15	15	35	20
Municipal Waste CHP autoproduction	2500							3-15	15	35	4-25
Industrial Waste CHP autoproduction	3500							3-15	15	35	12
Wood biomass CHP autoproduction	3500							3-15	15	35	14
Heat utilization and Separate boilers											
Generic Heat utilization	20							11-100	76-100	40	–
Separate steam boilers in Industry	500							81	1	40	–
Other technologies											
Chemical Absorption Direct Air Capture, electric	2.32	2.05	1.86	1.8	1.7	1.6	1.5	0.014-0.007 PJ/kt CO_2	90	25	–
Chemical Absorption Direct Air Capture, gas	2.32	2.05	1.86	1.8	1.7	1.6	1.5	0.014-0.007 PJ/kt CO_2	90	25	–
Methanation	600	500	450	400	350	300	250	75-83 (H2)	95	25	–
Hydrogen DRI production	360	355	350	345	340	333	324	17 PJ H2/ Mt DRI	85	40	–
Low carbon Iron ore concentrate production	96							64-75	1	30	–
Electrolyzer Alkaline, *€/ kW*	650	500	450	375	300	275	250	67-75	97	25-35	–
Electrolyzer PEM, *€/ kW*	925	800	650	550	450	425	400	58-71	97	20-30	–
Electrolyzer SOEC, *€/ kW*	4500	3200	1900	1620	1340	1060	780	77.5-83.5	91	10-20	–
Steam methane reforming Large			10.6					77	90	20	–
Steam methane reforming Small			22					69	80	20	–
Solar Methane Steam Reforming Large			9.8					120	90	20	–
Solar Methane Steam Reforming Small			27					60	90	20	–
Biomass Gasification to H2 Large			63.4	47.6				50	90	20	–
Biomass Gasification to H2 Small			111	95				33	71	20	–
Ethanol steam reforming			234					67	90	20	–

Annex 4:
Wholesale price

The following figures summarize the regional baseload wholesale electricity prices in the three different scenarios in 2030, 2040 and 2050.

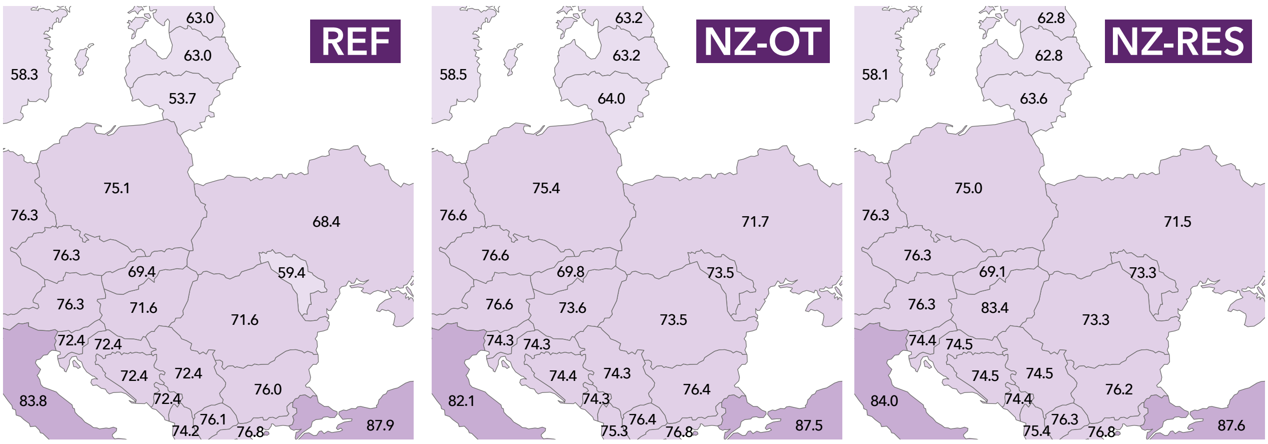
Figure 19: Regional baseload electricity prices, 2030



In 2030 Ukraine has substantial excess capacities in all scenarios. Despite the baseload price being higher in the Net Zero scenarios due to the carbon pricing relative to the Reference, Ukrainian prices remain cheaper than in the neighbouring countries in all three scenarios.

The decrease in available capacities in the Reference scenario, coupled with the installation of new renewable energy capacities during the decarbonization process up to 2040, results in a convergence of prices between Ukraine and the broader region. This convergence leads to marginal price differences with neighbouring countries by 2040.

Figure 20: Regional baseload electricity prices, 2040



In 2050 the price depends on the scenario. In the Net Zero-OT scenario Ukraine tend to be in the same price zone as the rest of the regional. In the Net Zero-RES and Reference scenarios, however, Ukraine becomes more expensive than its neighbours. The divergence is due to the different capacity mixes.

Figure 21: Regional baseload electricity prices, 2050

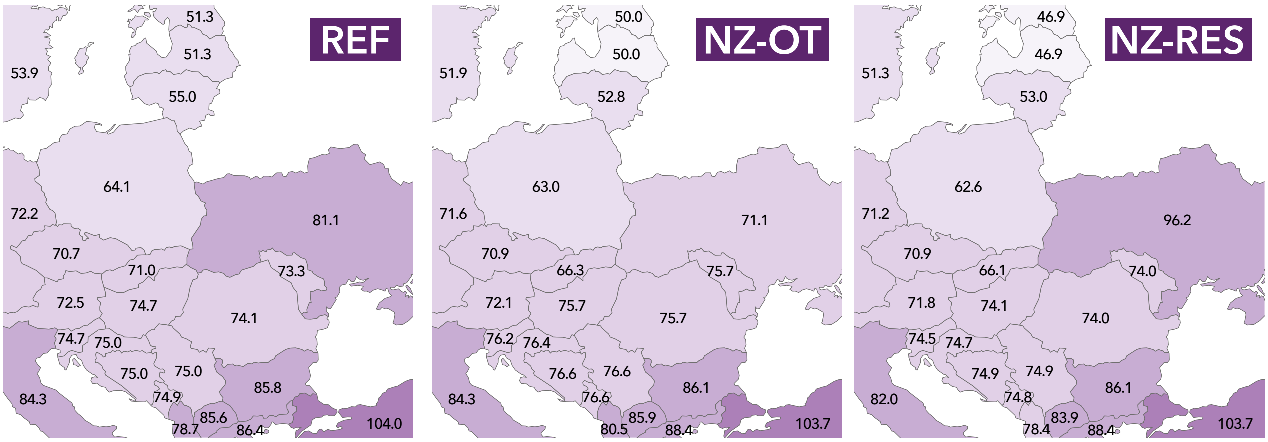
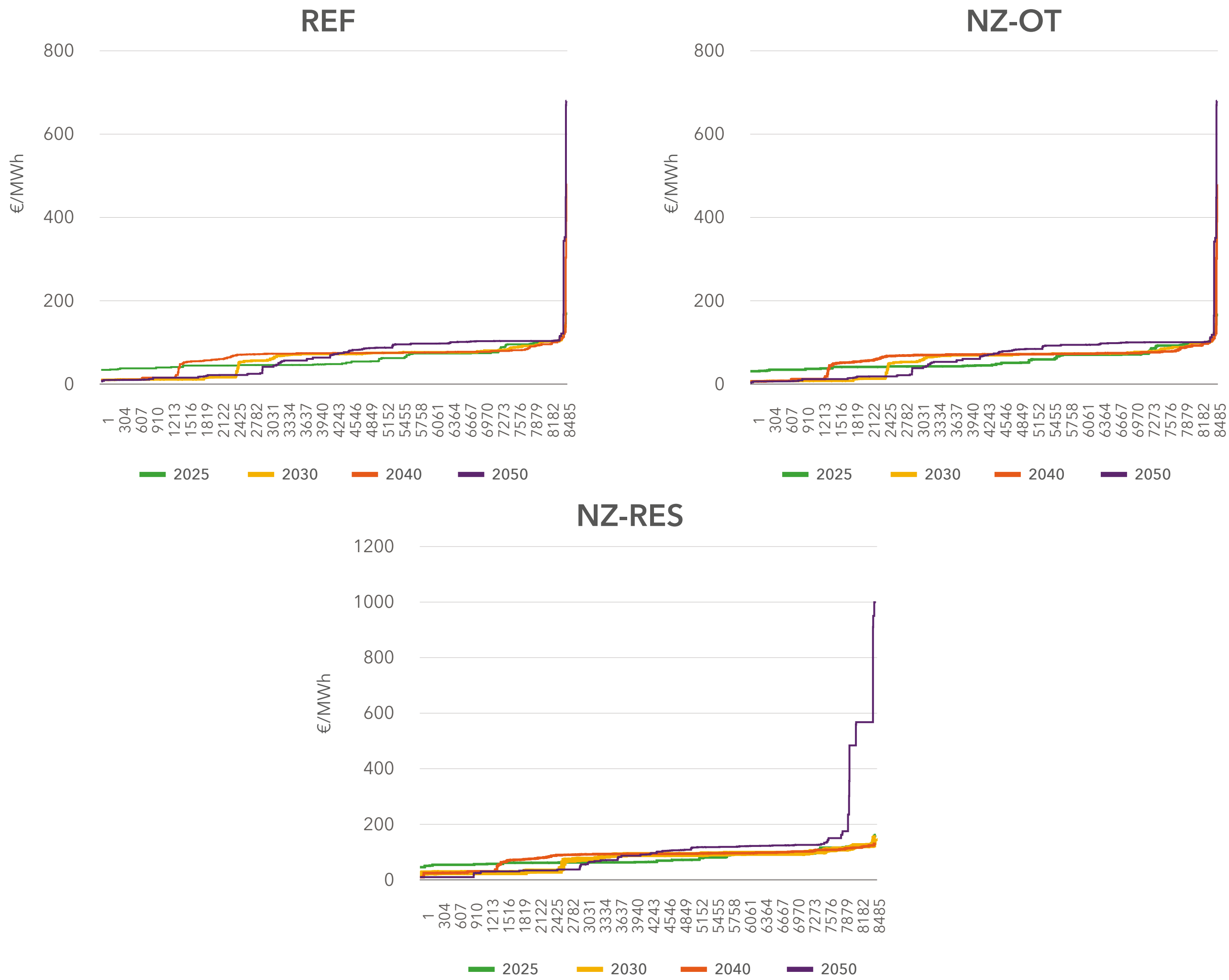


Figure 22 summarizes the hourly electricity prices in the three scenarios for the modelled years. The X-axis shows the distribution of the 8760 hours of the year, showing the frequency of the various hourly electricity prices. In essence, this axis illustrates the proportion of time, expressed in hours, during which the electricity price equals the specified price level.

Figure 22: Evolution of hourly prices in the 3 main scenarios



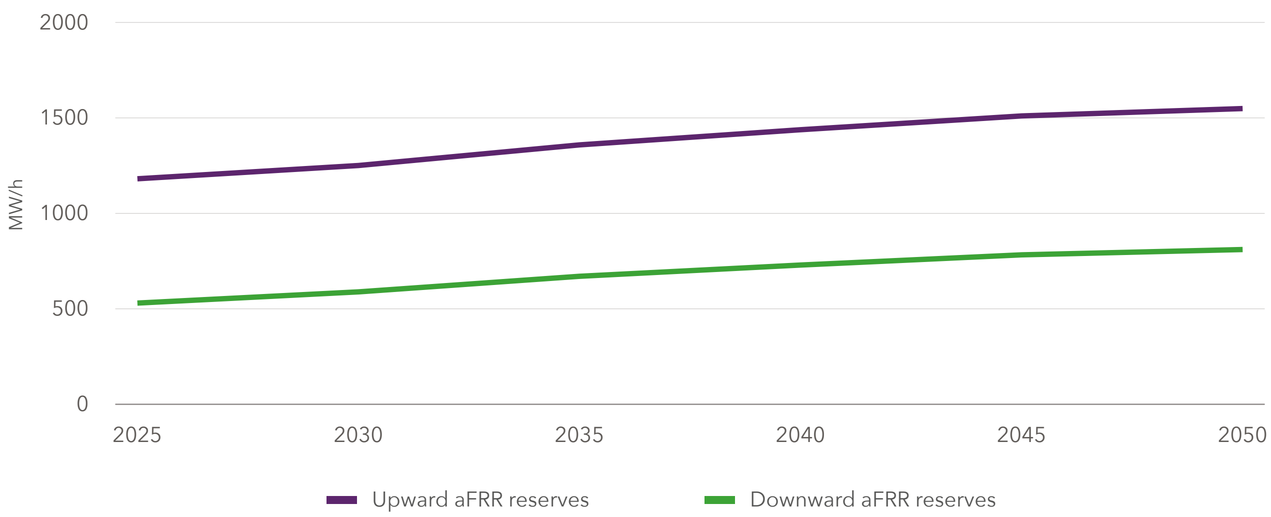
In the Reference and Net Zero-OT scenarios the occurrence of extremely high prices is low. In the Net Zero-RES scenario, however, price exceeds 200 €/MWh in more than 600 hours, primarily during sunny summer hours with minimal wind availability. These hours elevate the average price level in this scenario. It is also important to note that with the larger deployment of RES capacities especially in the Net Zero scenarios, hours with close to zero prices or zero prices tend to occur more frequently in the later periods.

Annex 5:

Reserve capacity needs

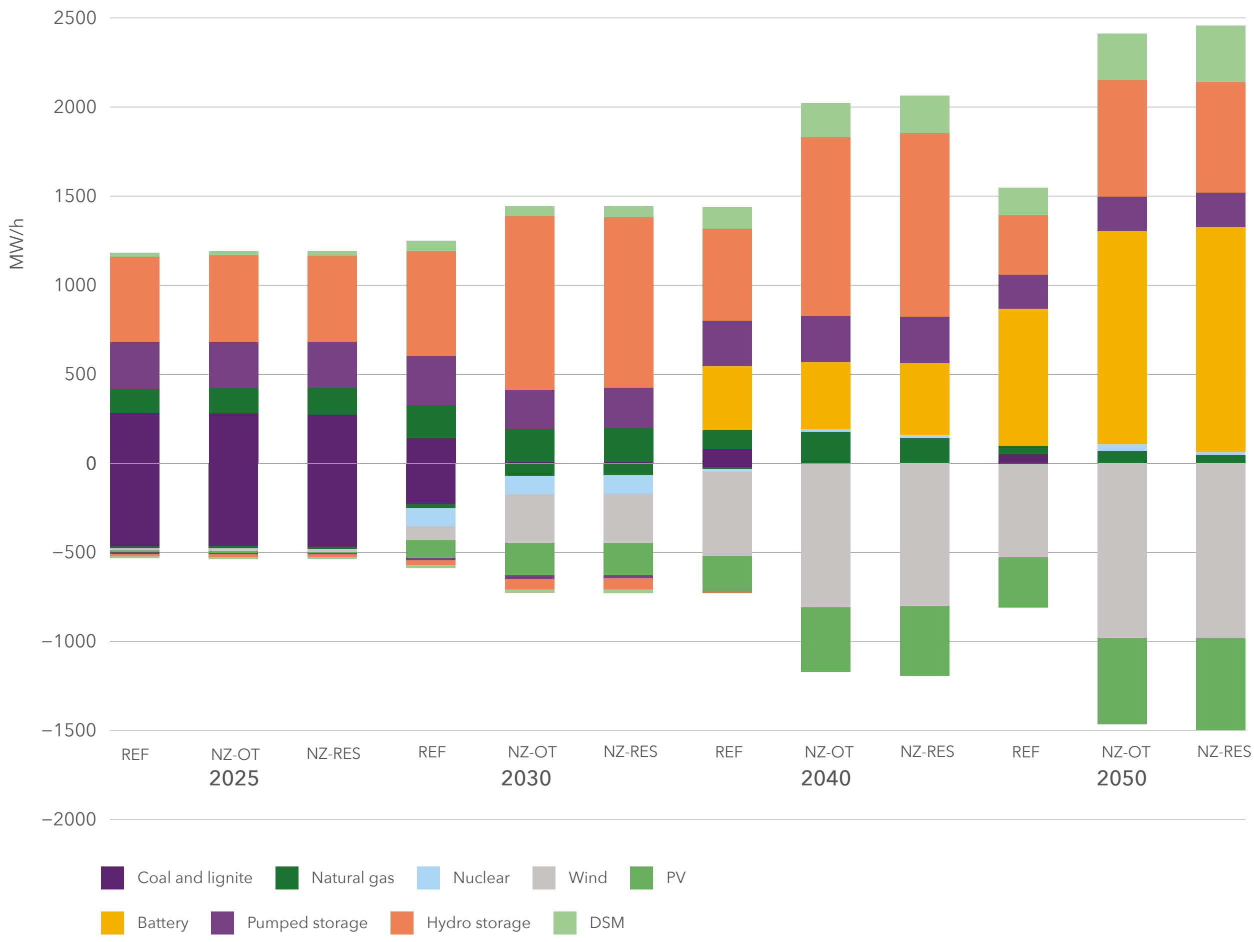
The next figure shows the assumed aFRR requirements, increasing with growing load variable renewables in the system.

Figure 23: Assumed aFRR requirements



Reserve requirements can be satisfied in all scenarios. In the upward direction, coal is replaced by hydro storage and the additional reserve requirements from 2040 are met by battery storage and DSM. In the downward direction, coal is partly replaced by nuclear and renewables in the Reference scenario and by gas and renewables in the Net Zero scenarios in 2030. The increasing downward reserve requirements after 2040 are served by PV and wind capacities mainly in all scenarios.

Figure 24: Composition of aFRR



Annex 6:

Detailed results tables for Ukraine power sector in the four assessed scenarios

		Reference						Reference+CBAM					
		2025	2030	2035	2040	2045	2050	2025	2030	2035	2040	2045	2050
Prices, €(2022)/MWh	Baseload price	65.7	42.5	69.1	68.4	76.6	81.1	53.8	34.1	45.2	46.6	48.5	58.5
	Peakload price	68.7	43.8	67.2	61.2	68.5	75.6	55.8	35.7	45.2	45.4	48.0	57.9
	PV market value	56.4	33.9	47.3	40.6	46.2	56.4	47.4	27.4	31.3	30.1	32.9	40.3
	Wind market value	70.4	45.8	73.9	71.9	80.7	85.6	56.9	36.9	49.6	51.4	54.0	63.6
Capacity mix, MW	Coal and lignite	17 240	8 192	5 438	4 566	4 743	5 223	17 240	8 192	5 438	4 566	4 743	5 223
	Natural gas	6 656	6 213	2 983	2 825	2 801	1 929	6 656	6 213	2 983	2 825	2 801	1 929
	Nuclear	7 835	13 835	13 835	11 970	9 970	7 740	7 835	13 835	13 835	11 970	9 970	7 740
	PV	7 194	8 334	12 200	15 304	18 071	19 092	7 194	8 334	12 200	15 304	18 071	19 092
	Wind - onshore	1 585	3 085	5 034	6 419	7 752	9 085	1 585	3 085	5 034	6 419	7 752	9 085
	Wind - offshore	0	500	1 500	2 590	4 000	4 927	0	500	1 500	2 590	4 000	4 927
	Run-of river	192	192	192	192	192	192	192	192	192	192	192	192
	Hydro Reservoir	4 439	4 549	4 549	4 562	4 562	4 572	4 439	4 549	4 549	4 562	4 562	4 572
	Other RES	1 102	1 262	1 378	1 543	1 798	1 986	1 102	1 262	1 378	1 543	1 798	1 986
	Battery	0	0	500	1 000	10 000	20 000	0	0	500	1 000	10 000	20 000
	Pumped storage	1 563	1 563	1 563	1 563	1 563	1 563	1 563	1 563	1 563	1 563	1 563	1 563
	DSM	534	1 346	2 286	3 258	4 297	5 257	534	1 346	2 286	3 258	4 297	5 257
Electricity mix, GWh	Coal and lignite	51 708	22 959	19 676	15 884	16 516	18 964	41 610	19 680	18 448	15 344	14 220	15 850
	Natural gas	5 376	9 575	15 613	15 319	17 839	9 765	1 765	3 133	4 465	6 424	7 478	5 590
	Nuclear	52 847	95 270	96 822	87 537	78 423	62 931	52 847	95 135	96 588	86 983	78 308	62 784
	PV	8 378	9 706	14 208	17 823	21 046	22 235	8 378	9 706	14 208	17 823	21 046	22 235
	Wind - onshore	4 583	8 921	14 556	18 561	22 416	26 270	4 583	8 921	14 556	18 561	22 416	26 270
	Wind - offshore	0	1 753	5 259	9 080	14 023	17 273	0	1 753	5 259	9 080	14 023	17 273
	Run-of river	507	507	507	507	507	507	507	507	507	507	507	507
	Hydro Reservoir	11 713	12 003	12 009	12 042	12 047	12 072	11 711	12 004	12 006	12 045	12 047	12 071
	Other RES	4 827	5 528	6 036	6 758	7 875	8 699	4 827	5 528	6 036	6 758	7 875	8 699
	Pumped storage	-380	-525	-652	-841	-827	-551	-325	-640	-839	-936	-511	-133
	Battery	0	0	-53	-115	-1 069	-1 807	0	0	-56	-110	-905	-1 434
	Energy not Supplied	0	0	0	0	0	0	0	0	0	0	0	0
	Net import	-13 127	-16 284	-18 483	-7 935	-4 748	9 177	733	-6 147	-4 740	2 590	8 733	16 328
	Consumption	126 432	149 414	165 051	174 623	182 865	185 541	126 637	149 579	165 535	175 072	183 477	186 042
	Net import ratio	-10.4%	-10.9%	-11.2%	-4.5%	-2.6%	4.9%	0.6%	-4.1%	-2.9%	1.5%	4.8%	8.8%
	RES share (%)	23.7%	25.7%	31.9%	37.1%	42.6%	46.9%	23.7%	25.7%	31.8%	37.0%	42.5%	46.8%
CO2eq emission of power and district heating sector, kt		66 009	38 349	30 245	27 415	28 187	29 969	54 274	33 084	25 271	23 815	22 648	26 000
Utilization	Coal and lignite	34.2%	32.0%	41.3%	39.7%	39.7%	41.4%	27.6%	27.4%	38.7%	38.4%	34.2%	34.6%
	Natural gas	9.2%	17.6%	59.7%	61.9%	72.7%	57.8%	3.0%	5.8%	17.1%	26.0%	30.5%	33.1%
	Nuclear	77.0%	78.6%	79.9%	83.5%	89.8%	92.8%	77.0%	78.5%	79.7%	83.0%	89.7%	92.6%
	Pumped storage	11.1%	15.3%	19.0%	24.6%	24.2%	16.1%	9.5%	18.7%	24.5%	27.4%	14.9%	3.9%
	Battery	na	na	12.1%	13.1%	12.2%	10.3%	na	na	12.8%	12.5%	10.3%	8.2%
RES curtailment, GWh	PV	0	-0	0	-0	-0	0	0	-0	0	-0	-0	0
	Wind	-0	-0	-0	0	-0	0	-0	-0	-0	0	-0	0
	Offshore	0	0	-0	0	-0	0	0	0	-0	0	-0	0
	Run-of-river	0	0	0	0	0	0	0	0	0	0	0	0

		Net Zero - Open Technology						Net Zero - Renewables					
		2025	2030	2035	2040	2045	2050	2025	2030	2035	2040	2045	2050
Prices, €(2022)/MWh	Baseload price	65.7	64.2	79.0	71.7	78.4	71.1	64.8	62.1	78.8	71.5	75.7	96.2
	Peakload price	69.0	61.9	73.3	62.7	69.9	63.4	68.1	60.6	73.1	61.5	66.4	81.9
	PV market value	56.9	41.4	52.9	41.0	51.7	51.7	56.8	41.5	53.0	39.6	46.2	78.8
	Wind market value	70.4	71.1	81.8	73.3	75.4	62.4	69.8	69.8	81.7	72.9	71.4	71.3
Capacity mix, MW	Coal and lignite	15 753	837	705	630	664	548	15 753	803	397	369	169	80
	Natural gas	7 002	5 741	4 913	4 289	3 978	2 609	7 002	5 721	5 092	4 551	3 830	2 584
	Nuclear	7 835	13 835	13 835	12 956	11 660	7 660	7 835	13 835	13 835	9 000	6 638	3 000
	PV	7 394	16 334	24 869	30 327	31 404	31 272	7 394	16 334	25 134	34 185	36 255	35 035
	Wind - onshore	2 085	6 885	13 085	23 085	29 518	42 869	2 085	6 885	13 085	23 085	28 826	42 652
	Wind - offshore	0	122	631	6 240	14 884	14 884	0	202	735	9 612	24 115	24 115
	Run-of river	146	256	283	303	303	303	146	256	277	293	293	293
	Hydro Reservoir	4 485	6 913	8 088	8 088	8 088	8 088	4 485	7 088	8 088	8 088	8 088	8 088
	Other RES	1 338	2 276	2 970	3 775	4 854	5 727	1 338	2 213	2 906	3 727	4 779	5 643
	Battery	0	0	500	1 000	10 000	20 000	0	0	500	1 000	10 000	20 000
	Pumped storage	1 563	1 563	1 563	1 563	1 563	1 563	1 563	1 563	1 563	1 563	1 563	1 563
	DSM	531	1 465	2 933	4 845	7 299	9 045	531	1 468	2 947	4 641	7 179	8 954
Electricity mix, GWh	Coal and lignite	47 406	295	814	174	0	14	47 400	286	459	116	4	29
	Natural gas	6 051	14 565	16 200	7 320	4 082	2 819	6 109	14 606	16 898	8 018	6 266	4 331
	Nuclear	52 847	92 384	96 521	93 703	89 813	57 011	52 847	92 426	96 507	64 381	49 188	19 155
	PV	8 611	19 023	28 963	35 307	36 523	36 246	8 611	19 023	29 271	39 730	42 027	40 101
	Wind - onshore	6 029	19 909	37 837	66 752	85 353	123 709	6 029	19 909	37 837	66 683	83 110	122 726
	Wind - offshore	0	428	2 212	21 850	52 130	51 862	0	708	2 577	33 507	84 495	83 679
	Run-of river	385	675	747	798	799	797	385	675	731	770	769	765
	Hydro Reservoir	11 834	18 244	21 346	21 358	21 361	21 356	11 834	18 706	21 345	21 359	21 363	21 361
	Other RES	5 860	9 969	13 009	16 535	21 261	25 084	5 860	9 693	12 728	16 324	20 932	24 716
	Pumped storage	-387	-499	-699	-842	-767	-603	-377	-478	-692	-873	-824	-761
	Battery	0	0	-59	-107	-981	-1 591	0	0	-60	-116	-1 232	-3 366
	Energy not Supplied	0	0	0	0	0	0	0	0	0	0	0	0
	Net import	-13 105	-12 949	-4 898	-3 958	2 165	2 018	-13 148	-13 041	-4 660	-1 819	1 487	1 892
	Consumption	125 533	162 044	211 193	258 894	309 614	318 731	125 552	162 515	212 147	248 084	304 672	314 638
	Net import ratio	-10.4%	-8.0%	-2.3%	-1.5%	0.7%	0.6%	-10.5%	-8.0%	-2.2%	-0.7%	0.5%	0.6%
	RES share (%)	26.1%	42.1%	49.3%	62.8%	70.2%	81.3%	26.1%	42.3%	49.3%	71.9%	82.9%	93.2%
CO2eq emission of power and district heating sector, kt		57 641	11 562	11 641	574	-7 128	-11 805	57 667	11 385	11 741	3 062	-4 972	-9 515
Utilization	Coal and lignite	34.4%	4.0%	13.2%	3.2%	0.0%	0.3%	34.3%	4.1%	13.2%	3.6%	0.3%	4.1%
	Natural gas	9.9%	29.0%	37.6%	19.5%	11.7%	12.3%	10.0%	29.1%	37.9%	20.1%	18.7%	19.1%
	Nuclear	77.0%	76.2%	79.6%	82.6%	87.9%	85.0%	77.0%	76.3%	79.6%	81.7%	84.6%	72.9%
	Pumped storage	11.3%	14.6%	20.4%	24.6%	22.4%	17.6%	11.0%	14.0%	20.2%	25.5%	24.1%	22.2%
	Battery	na	na	13.5%	12.3%	11.2%	9.1%	na	na	13.7%	13.2%	14.1%	19.2%
RES curtailment, GWh	PV	-0	-0	-0	12	50	173	-0	-0	-0	82	195	701
	Wind	0	0	-0	1	1	251	0	0	-0	70	243	607
	Offshore	0	0	0	27	52	319	0	-0	-0	191	49	865
	Run-of-river	0	0	0	1	0	3	0	0	0	3	4	8

			Reference						Reference+CBAM					
			2025	2030	2035	2040	2045	2050	2025	2030	2035	2040	2045	2050
Reserve capacity mix, MW	Upward	Coal and lignite	286	141	59	85	85	54	443	208	133	115	207	120
		Natural gas and other fossil	134	186	115	102	88	44	105	113	48	65	48	17
		Nuclear	0	0	0	1	0	2	0	0	0	4	1	4
		Wind	0	0	0	0	0	0	0	0	0	0	0	0
		PV	0	0	0	0	0	0	0	0	0	0	0	0
		Battery	0	0	205	358	628	769	0	0	202	378	600	767
		Pumped storage	260	276	290	255	206	191	226	274	281	244	183	180
		Hydro Reservoir	480	588	596	517	380	335	387	598	596	511	347	312
		DSM	21	59	93	119	123	154	20	58	99	121	124	149
		Missing reserve	0	0	0	0	0	0	0	0	0	0	0	0
		Total	1 181	1 251	1 359	1 438	1 510	1 549	1 181	1 251	1 359	1 438	1 510	1 549
	Downward	Coal and lignite	466	227	68	20	4	1	423	205	71	22	3	1
		Natural gas and other fossil	11	26	24	10	3	0	3	7	2	1	0	0
		Nuclear	0	100	25	11	3	0	0	120	32	14	5	1
		Wind	12	78	371	478	513	527	18	86	374	479	513	527
		PV	9	98	158	202	257	282	14	100	159	201	258	282
		Battery	0	0	4	2	1	0	0	0	5	2	1	0
		Pumped storage	9	14	6	2	1	0	30	19	8	3	1	0
		Hydro Reservoir	15	28	8	3	1	0	31	32	11	4	1	0
		DSM	8	18	7	2	1	0	11	19	8	3	1	0
		Missing reserve	0	0	0	0	0	0	0	0	0	0	0	0
		Total	530	589	671	729	783	811	530	589	671	729	783	811
Reserve price		Upward, €/MW	7.6	7.3	12.0	13.0	12.4	5.4	7.9	5.9	5.9	6.3	3.9	2.2
		Downward, €/MW	3.0	1.6	0.2	0.0	0.0	0.0	2.7	1.2	0.4	0.0	0.0	0.0
		Total cost, m€	93	88	145	165	164	73	94	71	72	79	51	30

		Net Zero - Open Technology						Net Zero - Renewables					
		2025	2030	2035	2040	2045	2050	2025	2030	2035	2040	2045	2050
Reserve capacity mix, MW	Coal and lignite	282	11	21	3	0	0	274	11	12	3	0	1
	Natural gas and other fossil	141	185	182	176	100	69	150	189	169	139	112	47
	Nuclear	0	0	0	17	21	41	0	0	0	21	36	19
	Wind	0	0	0	0	0	0	0	0	0	0	0	0
	PV	0	0	0	0	0	0	0	0	0	0	0	0
	Battery	0	0	171	374	959	1 194	0	0	179	401	1 023	1 260
	Pumped storage	257	220	223	256	206	196	261	228	234	261	200	194
	Hydro Reservoir	489	971	1 019	1 006	706	652	483	955	1 015	1 031	645	621
	DSM	21	56	113	189	210	258	23	61	125	209	241	316
	Missing reserve	0	0	0	0	0	0	0	0	0	0	0	0
	Total	1 190	1 443	1 728	2 022	2 202	2 410	1 190	1 444	1 734	2 064	2 257	2 458
	Coal and lignite	463	2	0	0	0	0	467	2	0	0	0	0
	Natural gas and other fossil	14	68	8	0	0	0	14	66	9	0	0	0
	Nuclear	0	103	24	0	0	0	0	102	24	0	0	0
	Wind	15	273	611	809	882	980	16	277	615	802	886	983
	PV	10	182	266	360	436	484	10	183	267	391	466	512
	Battery	0	0	3	0	0	0	0	0	2	0	0	0
	Pumped storage	10	20	8	0	0	0	3	18	8	0	0	0
	Hydro Reservoir	16	60	17	0	0	0	16	60	17	0	0	0
	DSM	9	18	7	0	0	0	11	20	7	0	0	0
	Missing reserve	0	0	0	0	0	0	0	0	0	0	0	0
	Total	536	727	946	1 169	1 318	1 464	536	727	950	1 193	1 353	1 495
Reserve price	Upward, €/MW	8.2	9.3	10.7	5.6	2.5	2.8	7.6	7.8	10.4	5.5	5.5	9.6
	Downward, €/MW	1.7	0.7	0.0	0.0	0.0	0.0	0.4	0.4	0.0	0.0	0.0	0.0
	Total cost, m€	93	122	162	99	49	59	81	101	158	100	109	206

			Reference						Reference+CBAM					
			2025	2030	2035	2040	2045	2050	2025	2030	2035	2040	2045	2050
Cross-border capacity, MW	Export	HU	429	429	650	650	650	650	429	429	650	650	650	650
		MD	172	172	260	260	260	260	172	172	260	260	260	260
		PL	799	799	1 210	1 210	1 210	1 210	799	799	1 210	1 210	1 210	1 210
		RO	198	264	1 400	1 400	1 400	1 400	198	264	1 400	1 400	1 400	1 400
		SK	264	264	1 400	1 400	1 400	1 400	264	264	1 400	1 400	1 400	1 400
	Import	HU	297	363	550	550	450	450	297	363	550	550	450	450
		MD	264	264	400	400	400	400	264	264	400	400	400	400
		PL	660	660	1 000	1 000	1 000	1 000	660	660	1 000	1 000	1 600	1 600
		RO	99	264	1 400	1 400	1 400	1 400	99	264	1 400	1 400	1 400	1 400
		SK	264	264	1 400	1 400	1 400	1 400	264	264	1 400	1 400	1 400	1 400
Cross-border trade, GWh	Export	HU	3 548	3 674	4 241	3 675	3 450	2 613	130	1 245	1 618	906	207	0
		MD	190	1 354	290	109	1 132	756	15	483	419	166	764	556
		PL	6 979	6 994	6 829	5 167	4 645	2 143	921	4 120	1 843	813	80	13
		RO	1 607	2 243	9 005	7 494	7 266	5 651	3	606	3 058	1 718	373	0
		SK	2 178	2 247	5 741	3 895	3 978	2 491	82	719	1 644	647	78	0
	Import	HU	109	57	148	376	1 229	1 852	62	40	177	386	1 025	1 621
		MD	1 126	90	2 194	2 722	1 088	1 539	1 745	930	2 133	2 584	1 622	2 148
		PL	0	0	1 650	3 129	3 774	6 265	2	3	266	973	1 179	3 090
		RO	44	37	874	1 738	3 488	5 037	21	22	438	988	2 619	4 135
		SK	98	45	2 756	4 440	6 143	8 138	55	31	828	1 910	3 791	5 903
Cross border utilization, %	Export	HU	94.4%	97.8%	74.5%	64.5%	60.6%	45.9%	3.5%	33.1%	28.4%	15.9%	3.6%	0.0%
		MD	12.7%	90.1%	12.7%	4.8%	49.7%	33.2%	1.0%	32.1%	18.4%	7.3%	33.5%	24.4%
		PL	99.8%	100.0%	64.4%	48.7%	43.8%	20.2%	13.2%	58.9%	17.4%	7.7%	0.8%	0.1%
		RO	92.7%	97.0%	73.4%	61.1%	59.2%	46.1%	0.2%	26.2%	24.9%	14.0%	3.0%	0.0%
		SK	94.2%	97.2%	46.8%	31.8%	32.4%	20.3%	3.6%	31.1%	13.4%	5.3%	0.6%	0.0%
	Import	HU	4.2%	1.8%	3.1%	7.8%	31.2%	47.0%	2.4%	1.3%	3.7%	8.0%	26.0%	41.1%
		MD	48.7%	3.9%	62.6%	77.7%	31.1%	43.9%	75.4%	40.2%	60.9%	73.7%	46.3%	61.3%
		PL	0.0%	0.0%	18.8%	35.7%	43.1%	71.5%	0.0%	0.0%	3.0%	11.1%	8.4%	22.0%
		RO	5.0%	1.6%	7.1%	14.2%	28.4%	41.1%	2.4%	0.9%	3.6%	8.1%	21.4%	33.7%
		SK	4.2%	1.9%	22.5%	36.2%	50.1%	66.4%	2.4%	1.4%	6.8%	15.6%	30.9%	48.1%
Share of congested hours, %	Export	HU	93.3%	96.9%	60.7%	48.0%	49.9%	28.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
		MD	11.2%	87.5%	3.4%	1.5%	42.2%	23.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
		PL	99.4%	99.8%	50.3%	34.8%	34.8%	14.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
		RO	90.9%	95.4%	59.6%	44.2%	47.1%	27.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
		SK	93.2%	96.2%	32.2%	16.6%	22.5%	12.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Import	HU	3.3%	1.4%	0.1%	1.7%	22.9%	36.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
		MD	17.8%	1.0%	45.8%	57.8%	20.8%	33.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
		PL	0.0%	0.0%	8.5%	22.8%	30.2%	60.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
		RO	4.2%	1.0%	0.4%	2.5%	21.6%	34.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
		SK	3.3%	1.4%	8.1%	15.4%	37.2%	54.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

		Net Zero - Open Technology						Net Zero - Renewables					
		2025	2030	2035	2040	2045	2050	2025	2030	2035	2040	2045	2050
Cross-border capacity, MW	HU	429	429	650	650	650	650	429	429	650	650	650	650
	MD	172	172	260	260	260	260	172	172	260	260	260	260
	PL	799	799	1 210	1 210	1 210	1 210	799	799	1 210	1 210	1 210	1 210
	RO	198	264	1 400	1 400	1 400	1 400	198	264	1 400	1 400	1 400	1 400
	SK	264	264	1 400	1 400	1 400	1 400	264	264	1 400	1 400	1 400	1 400
	HU	297	363	550	550	450	450	297	363	550	550	450	450
	MD	264	264	400	400	400	400	264	264	400	400	400	400
	PL	660	660	1 000	1 000	1 000	1 000	660	660	1 000	1 000	1 000	1 000
	RO	99	264	1 400	1 400	1 400	1 400	99	264	1 400	1 400	1 400	1 400
	SK	264	264	1 400	1 400	1 400	1 400	264	264	1 400	1 400	1 400	1 400
Cross-border trade, GWh	HU	3 554	3 216	3 454	3 465	2 969	2 962	3 562	3 221	3 441	3 269	2 880	2 858
	MD	172	1 222	1 097	1 090	992	1 055	171	1 232	1 060	981	986	1 000
	PL	6 979	6 150	3 917	3 251	3 499	3 263	6 980	6 167	3 794	3 103	3 694	3 566
	RO	1 611	1 918	7 704	7 893	6 519	6 518	1 622	1 934	7 699	7 471	6 336	6 295
	SK	2 181	1 770	1 833	2 388	2 829	3 749	2 186	1 774	1 782	2 447	3 307	4 055
	HU	105	233	305	387	1 405	1 736	101	219	294	493	1 472	1 770
	MD	1 152	203	351	380	1 102	1 315	1 143	204	389	473	1 156	1 343
	PL	0	407	4 059	4 967	4 841	5 006	0	399	4 104	5 309	4 576	5 049
	RO	42	184	1 283	1 447	4 009	4 735	39	174	1 207	1 799	4 206	4 790
	SK	94	300	7 109	6 947	7 614	6 774	90	291	7 120	7 378	7 280	6 714
Cross border utilization, %	HU	94.6%	85.6%	60.7%	60.9%	52.1%	52.0%	94.8%	85.7%	60.4%	57.4%	50.6%	50.2%
	MD	11.4%	81.3%	48.2%	47.8%	43.6%	46.3%	11.4%	82.0%	46.5%	43.1%	43.3%	43.9%
	PL	99.8%	87.9%	37.0%	30.7%	33.0%	30.8%	99.8%	88.2%	35.8%	29.3%	34.9%	33.6%
	RO	92.9%	82.9%	62.8%	64.4%	53.2%	53.2%	93.5%	83.6%	62.8%	60.9%	51.7%	51.3%
	SK	94.3%	76.5%	14.9%	19.5%	23.1%	30.6%	94.5%	76.7%	14.5%	20.0%	27.0%	33.1%
	HU	4.0%	7.3%	6.3%	8.0%	35.7%	44.0%	3.9%	6.9%	6.1%	10.2%	37.3%	44.9%
	MD	49.8%	8.8%	10.0%	10.8%	31.4%	37.5%	49.4%	8.8%	11.1%	13.5%	33.0%	38.3%
	PL	0.0%	7.0%	46.3%	56.7%	55.3%	57.1%	0.0%	6.9%	46.8%	60.6%	52.2%	57.6%
	RO	4.8%	7.9%	10.5%	11.8%	32.7%	38.6%	4.5%	7.5%	9.8%	14.7%	34.3%	39.1%
	SK	4.1%	13.0%	58.0%	56.6%	62.1%	55.2%	3.9%	12.6%	58.1%	60.2%	59.4%	54.7%
Share of congested hours, %	HU	93.6%	77.4%	35.6%	37.9%	36.4%	38.4%	93.5%	77.9%	34.4%	31.1%	36.1%	36.7%
	MD	10.2%	75.9%	34.6%	36.9%	34.5%	37.6%	10.2%	77.4%	29.5%	27.6%	35.4%	36.0%
	PL	99.4%	82.6%	22.9%	22.9%	22.6%	18.5%	99.5%	82.3%	21.9%	23.2%	26.6%	25.5%
	RO	91.3%	76.1%	37.5%	38.5%	36.7%	38.5%	92.1%	77.7%	37.0%	31.2%	36.5%	37.8%
	SK	93.5%	70.5%	4.2%	8.6%	12.5%	17.2%	93.3%	71.4%	3.7%	9.7%	17.0%	23.1%
	HU	3.2%	3.5%	1.2%	2.3%	25.8%	33.4%	3.2%	3.6%	1.3%	3.1%	26.8%	34.3%
	MD	17.6%	3.7%	1.1%	2.2%	19.5%	31.0%	17.3%	3.4%	1.2%	2.8%	20.4%	31.2%
	PL	0.0%	4.4%	34.1%	44.1%	40.2%	45.2%	0.0%	4.6%	34.7%	51.0%	42.0%	47.2%
	RO	4.1%	3.7%	1.1%	2.3%	20.8%	31.5%	3.9%	3.4%	1.2%	3.2%	21.8%	32.1%
	SK	3.2%	7.6%	35.5%	38.5%	47.3%	42.7%	3.2%	7.5%	36.3%	45.1%	49.2%	44.4%

Annex 7:

Details on the resource assessment and the regional distribution of solar PV and wind onshore

GIS-based assessment of technical resource potentials for key RES technologies

For key renewable energy technology options for future power supply a GIS-based analysis of the applicable resources has been conducted by the TU Wien team during this study. That includes in the case of Ukraine wind onshore and solar PV. The results of this analysis are applicable at a regional split, distinguishing the Ukraine territory between 27 regions. The findings on applicable resource potentials and related site qualities have been incorporated in the subsequent energy sector modelling. At a later point in time, once the energy system modelling done at country level was completed, the GIS-based resource assessment served for redistributing the model outcomes back to regions.

This section summarises the approach taken in the GIS-based resource assessment, and it briefly presents the outcomes.

1. As first step for the GIS-based assessment of solar and wind resources, a comprehensive meteorological dataset on time-series of solar radiation and wind speeds is processed under a detailed geographical resolution for past weather years, serving as a basis for identifying unconstrained resource potentials across the whole study region.

   The approach and data source differ by technology:

   - In the case of solar PV, the data source is the PVGIS database (cf. https://re.jrc.ec.europa.eu/pvg_tools/en) and we use times series from 2005 to 2016 for calculating the average Global Horizontal Irradiation at each location. For estimating the electricity generation potential at a given site, we assume a PV module efficiency of 16%, a performance ratio of 75%[23] to account for all other losses of the PV system (incl. inverter, shading, temperature losses, etc.) and an effective module area of 35%, implying that only a bit more than a third of the available horizontal area can be covered by PV modules.
   - In the case of wind, wind speed data is taken from COSMO-REA6, representing a global reanalysis of meteorological data combined with a large set of observations (cf. Bollmeyer et al., 2014).[24] Weather data is then matched with a wind turbine power curve**.** The result is an hourly time-series for all COSMO-REA6 pixels with theoretical load factors. The average load factor over all hours, expressed as full load hours and ranging from 1995 to 2018, is calculated and serves as base for further calculations. To account for shading

23 For small-scale PV systems at the built environment a further discount by 5% is applied, accounting for non-optimal placing of modules at given rooftops or other building parts.

24 The underlying weather analysis open-source dataset is COSMO-REA6. It provides pre-calculated hourly wind speeds at 150 m height and at a geographical resolution of 6 km times 6 km.

effects within a wind farm, an efficiency factor of 85% is thereby applied. The following turbine characteristics are thereby applied: Our onshore wind turbine is the Nordex N163, characterised by a hub height of 150 m and a rotor diameter of 163 m. That turbine is equipped with a 4.95 MW electric generator. The space required for one turbine within a wind farm is assumed to be 4.5 times the rotor diameter, corresponding to a wind power plant density of 9.2 MW per km^2.

2. As next step, processed weather data is matched with **land use information** taken from the Globe Land Cover land use database (as of 2021). Land use data comes at a detailed geographical resolution (100 m x 100 m), requiring a retransformation of the solar and wind data. Within this step, **spatial constraints are incorporated** that stem from competing land use, such as nature protection (e.g., by excluding Natura 2000 protected areas) – here the assumptions differ between wind and solar as applicable from Table 7.

Table 7: Average suitability factors applied for the identification of solar PV and wind onshore potentials by land use category

Land use category	Average suitability factor* for solar PV	Average suitability factor for wind onshore
Built environment, Inland waters, wetlands	5%	0%
Agricultural areas	1%	40%
Other land (grass land, bare land)	1%	30%
Forestry areas	0	10%
Nature protection areas	0%	0%

**Suitability factor: share of land available for installations*

3. **Distance rules (specifically for onshore wind):** The process of matching with land use data comprises for onshore wind also the incorporation of distance rules and, in consequence, the further exclusion of areas not suitable for wind power development due to different constraints and aspects:

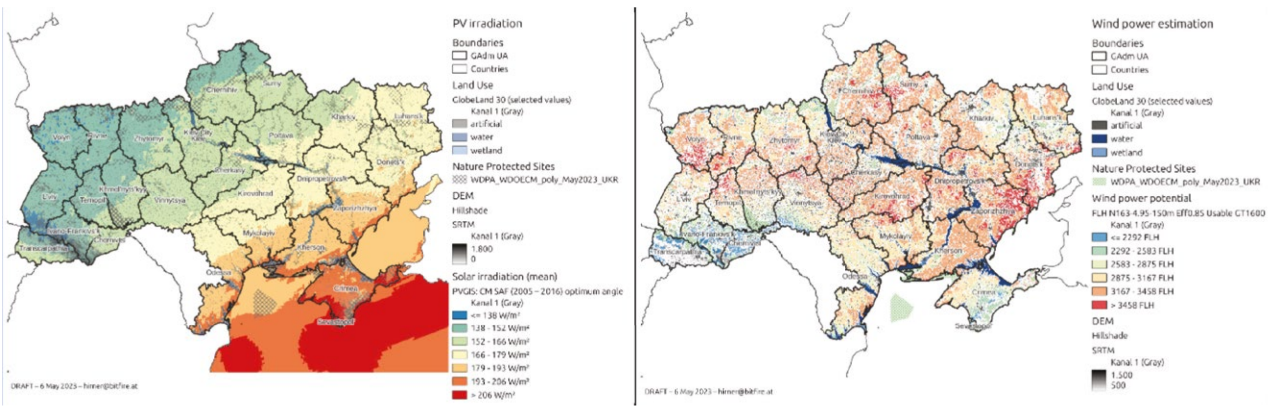
- Techno-economic constraints: We exclude areas above an altitude of 2000 m and above a slope of 20° to account for possible technical challenges and/or high cost related to grid connection.
- Social acceptance and avoidance of use conflicts: Built-up areas (incl. artificial surfaces like urban fabrics, industrial or commercial units, port areas, airports, construction sites, green urban areas, sport and leisure facilities) and infrastructure areas (incl. road and rail networks and associated land, mineral extraction sites, dump sites) are generally excluded. For the built-up areas a buffering of 1200 m is applied, respecting that wind power development should not harm the local community via noise or shading, etc.
- Economic constraints: We exclude areas of low wind speeds to account for the economic viability of wind power development. That implies to exclude areas below 1,700 effective full load hours (i.e., considering the efficiency factor of 0.85 as discussed above).

4. **Classification by area:** For the further processing in database format, the values of the usable (i.e., not excluded) pixels are aggregated by administrative boundaries, with slight differences in the detailed accounting by technology:

- For solar PV this implies a breakdown by region of the Ukraine and the application of a distinction between technology subcategories, i.e., small-scale PV systems installed at the built environment and large-scale PV systems installed at free fields (in agricultural areas and other grass or bare land).
- For onshore wind this implies a breakdown by region of the Ukraine and a distinction between wind power site qualities (i.e., 12 categories of different wind site qualities, represented by ranges of full load hours, predefined for the whole study region).

Below we briefly describe the outcomes of the GIS-based resource analysis. As starting point, Figure 25 illustrates the solar (left) and wind map (right) of the Ukraine, indicating site qualities by means of average solar irradiation (left) in the case of solar PV (left) and full load hours in the case of onshore wind (right). Complementary to that, Table 8 lists the results in table format for all regions of Ukraine. More precisely, this table provides a regional breakdown of the identified technical potentials in energy and capacity terms, and it also inform on average site qualities by means of full load hours. For solar PV a distinction is applied between small-scale PV installations in the built environment and large-scale PV systems in the free field (mainly at agricultural areas). A graphical illustration of the applicable technical potentials in capacity terms at regional level is given by Figure 26 for solar PV, with distinction between small-scale PV systems at the built environment and large-scale free field PV systems. The corresponding depiction for wind onshore is shown in Figure 27. Here the colour code informs on applicable site qualities, distinguishing between four different site quality categories (i.e., from low to excellent).

Figure 25: Solar (left) and wind (right) map of Ukraine, indicating average solar irradiation (left) or full load hours (right) by location



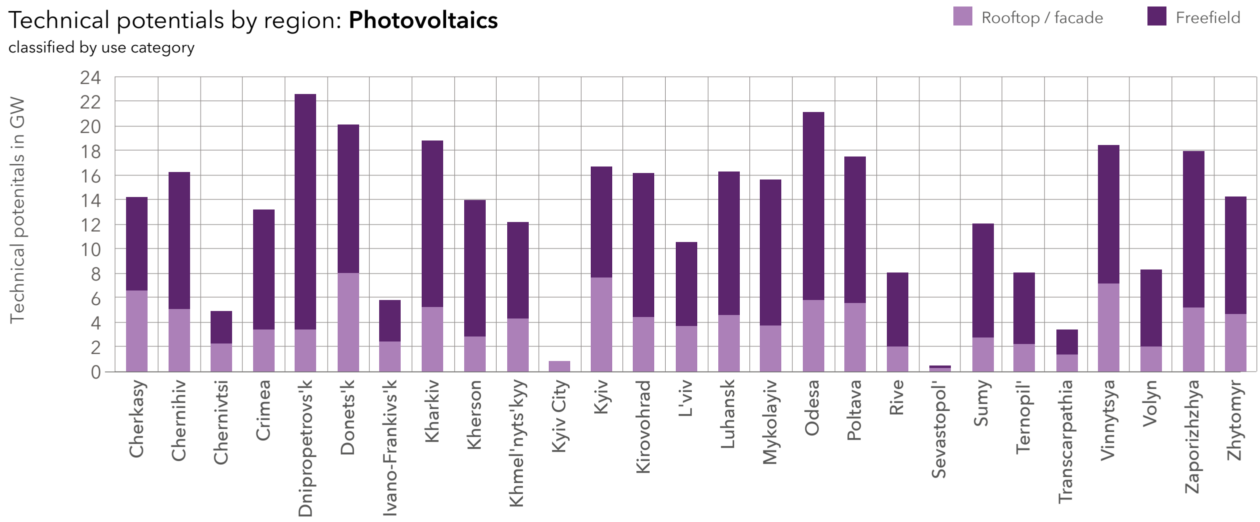
Source: own assessment based on PVGIS (left) and Cosmo-REA6 (right) data.

Table 8: Regional breakdown of identified technical potentials (with consideration of land use constraints) for solar PV and wind onshore in Ukraine

	Aggregate picture			5% discount for solar radiation for non- optimal placement								
	Photovoltaics			**PV rooftop/facade**			**PV freefield**			**Wind onshore**		
	Energy potential (in TWh)	Capacity potential (in GW)	Full load hours (in h/a)	Energy potential (in TWh)	Capacity potential (in GW)	Full load hours (in h/a)	Energy potential (in TWh)	Capacity potential (in GW)	Full load hours (in h/a)	Energy potential (in TWh)	Capacity potential (in GW)	Full load hours (in h/a)
Cherkasy	14.8	14.2	1046.7	6.8	6.6	1018.2	8.1	7.5	1071.8	86.8	26.8	3238.9
Chernihiv	16.0	16.3	986.9	4.9	5.1	952.6	11.2	11.1	1002.7	190.1	58.3	3262.6
Chernivtsi	5.0	5.0	1002.4	2.3	2.3	975.0	2.7	2.7	1026.4	21.5	10.4	2070.0
Crimea	17.1	13.2	1297.2	4.4	3.5	1248.9	12.7	9.7	1314.7	132.6	46.7	2839.5
Dnipropetrovs'k	25.4	22.6	1124.0	8.9	8.2	1087.6	16.5	14.4	1144.8	187.8	57.4	3272.1
Donets'k	22.8	20.1	1135.8	8.9	8.0	1101.1	14.0	12.0	1159.1	149.6	46.0	3253.9
Ivano-Frankivs'k	5.4	5.8	929.7	2.2	2.5	902.4	3.2	3.3	949.9	39.5	17.6	2243.9
Kharkiv	20.4	18.8	1080.6	5.5	5.3	1041.2	14.8	13.5	1096.0	187.1	61.0	3069.7
Kherson	17.1	14.0	1222.0	3.5	3.0	1173.4	13.6	11.0	1235.1	183.9	56.9	3233.2
Khmel'nyts'kyy	12.0	12.2	982.2	4.2	4.4	950.3	7.8	7.8	1000.3	88.3	28.7	3072.6
Kyiv City	1.0	1.0	981.8	0.9	1.0	980.1	0.0	0.0	1031.7	0.6	0.2	2882.8
Kyiv	16.8	16.7	1002.4	7.5	7.7	974.7	9.3	9.0	1026.0	123.1	39.1	3149.3
Kirovohrad	17.7	16.2	1092.3	4.8	4.5	1052.3	12.9	11.7	1107.7	168.0	50.7	3317.2
L'viv	9.8	10.6	921.4	3.4	3.8	891.4	6.4	6.8	938.3	176.3	56.9	3096.7
Luhans'k	18.4	16.3	1125.5	5.1	4.7	1084.7	13.3	11.7	1141.8	85.2	28.4	3003.3
Mykolayiv	18.2	15.7	1162.9	4.3	3.8	1118.4	14.0	11.9	1177.2	173.3	55.3	3133.1
Odesa	25.1	21.2	1187.8	6.8	5.9	1144.5	18.4	15.2	1204.7	204.0	68.3	2987.5
Poltava	18.6	17.5	1058.9	5.8	5.6	1022.3	12.8	11.9	1076.2	160.5	49.7	3233.0
Rivne	7.6	8.1	941.8	1.9	2.1	906.3	5.7	6.0	954.0	108.0	33.7	3204.8
Sevastopol'	0.7	0.5	1434.0	0.5	0.4	1412.3	0.2	0.2	1486.6	0.9	0.5	1861.8
Sumy	12.1	12.1	1001.2	2.7	2.8	962.3	9.4	9.3	1013.0	152.8	46.8	3265.9
Ternopil'	7.8	8.1	964.0	2.2	2.3	929.2	5.6	5.8	978.1	73.5	24.0	3066.4
Transcarpathia	3.4	3.5	961.5	1.4	1.5	932.9	2.0	2.0	982.0	13.6	6.8	1997.3
Vinnytsya	19.0	18.5	1030.3	7.2	7.2	998.3	11.8	11.2	1050.8	115.5	38.8	2973.3
Volyn	7.8	8.3	930.0	1.8	2.1	894.6	5.9	6.3	941.7	112.6	34.4	3269.2
Zaporizhzhya	21.3	18.0	1185.2	6.0	5.3	1142.6	15.3	12.7	1202.8	194.0	56.6	3427.2
Zhytomyr	13.9	14.3	973.8	4.4	4.7	940.8	9.4	9.5	990.3	141.7	44.8	3166.3
Total	**375.2**	**348.7**	**1075.9**	**118.2**	**114.4**	**1032.9**	**257.0**	**234.3**	**1096.9**	**3271.0**	**1044.6**	**3131.2**

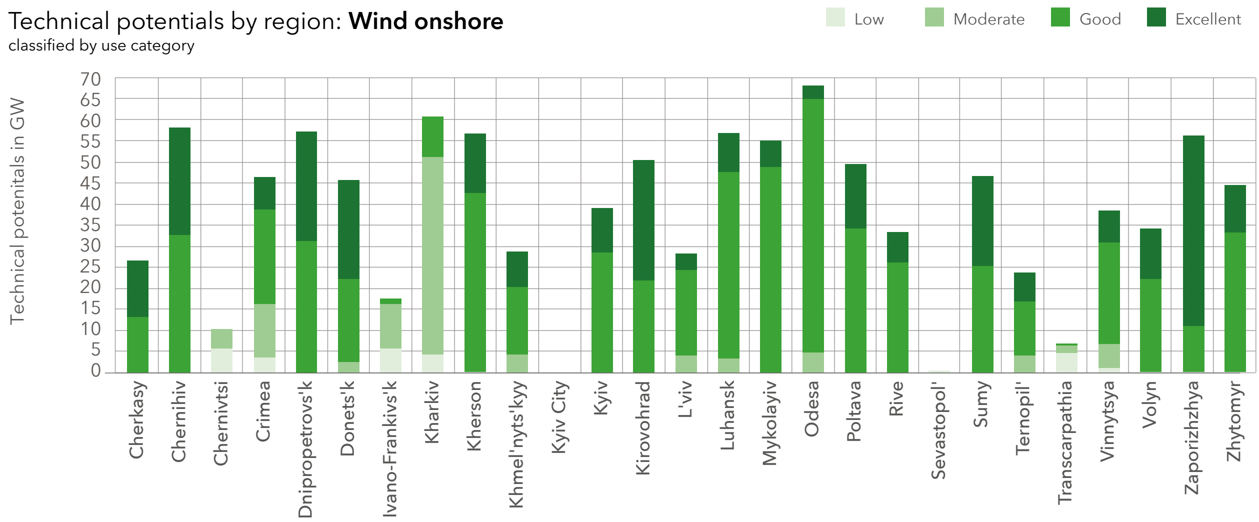
Source: own assessment.

Figure 26: Technical potentials for solar PV in capacity terms (GW) by region of Ukraine, with distinction between small-scale PV systems at the built environment and large-scale free field PV systems



Source: own assessment.

Figure 27: Technical potentials for wind onshore in capacity terms (GW) by region of Ukraine, with indication of site qualities (from low to excellent)



Source: own assessment.

As applicable from these illustrations, the best sites for solar PV installation can be found in the south and southeast of Ukraine but also other parts do offer sites worth being exploited when considering the economic viability of that technology. The technical potential in capacity terms is quite evenly spread across the regions of the country – here the available areas are determining the outcome.

For onshore it is noticeable that Ukraine offers excellent sites for wind power development in various regions, nicely spread across the country. Among those, the largest density of best sites can be found in the southeast of Ukraine. In general, the site quality for wind onshore can be classified as excellent: Ukraine offers some of the best wind sites of the whole European continent.

We can conclude that the technical potentials for solar and wind development in Ukraine are from a resource and land use perspective not the limiting factor for the future uptake of RES. From today's perspective, the necessary grid and market uptake as well as market / grid integration may rather act as limiting factors in this respect.

Complementary results on the regional distribution of RES deployment in accordance with modelling

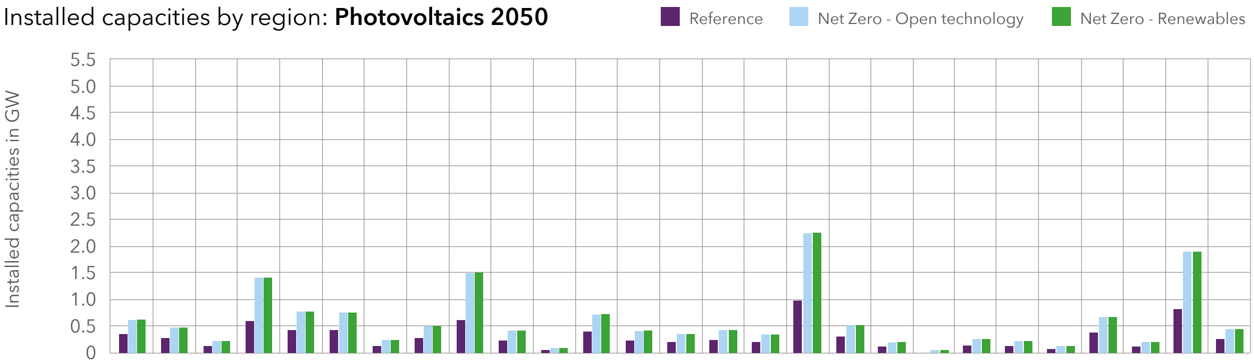
This section complements the description of the regional distribution of RES deployment in the main part of the report, in the Capacity mix section, including apart from 2050 also other years (2030, 2040) as well as a comparison with the outcomes of the resource assessment as discussed above.

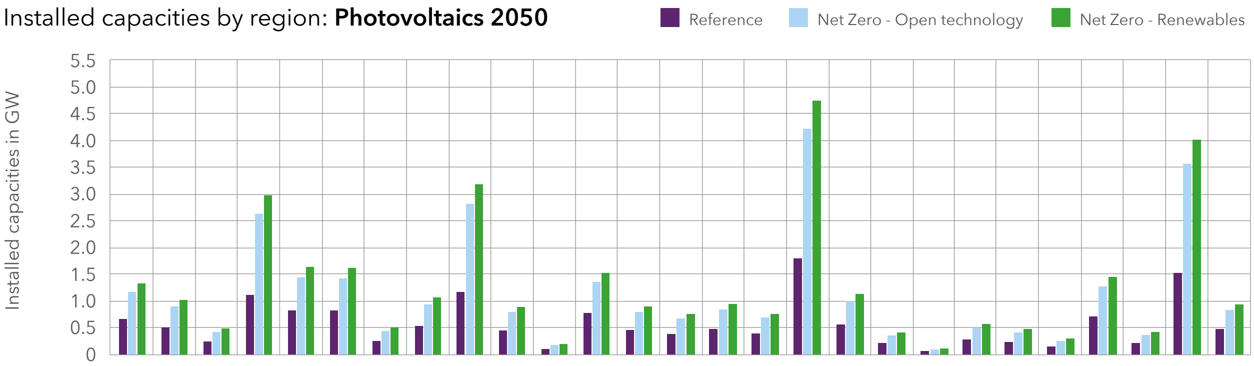
As described previously, for **solar PV** the allocation of installed capacities to individual regions of Ukraine differs by technology subcategory. For small-scale PV systems installed at the built environment the available areas at a regional level are the determining factor whereas for large-scale ground-mounted PV systems, the resource quality is assumed to predetermine the allocation process. Thus, for those type of PV systems the top five regions in terms of resource qualities (i.e., by means of region-specific average full load hours) are selected and installed PV capacities are distributed according to available area potentials (including mainly agricultural areas). The outcomes of the regional distribution are illustrated below. Thus, Figure 28 provides a cross-scenario comparison of the regional breakdown of installed PV capacities for specific years (2030, 2040, 2050) over time. Figure 29 complements the above with a comparison of how much of the identified potential is exploited in the final year 2050.

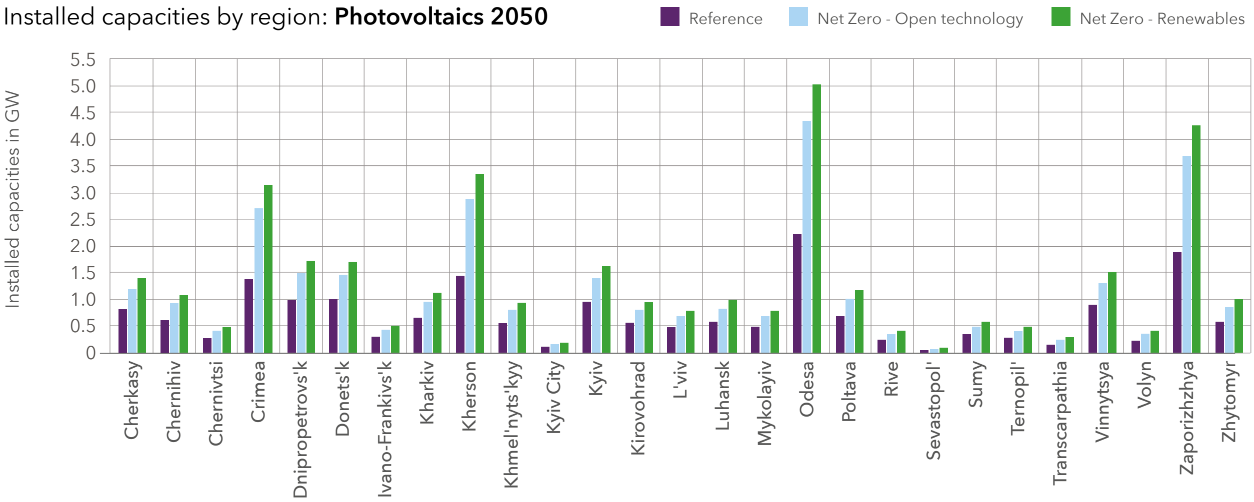
For **onshore wind** the allocation of installed capacities to individual regions of Ukraine follows a least-cost principle and consequently acknowledges the resource quality of available wind sites across the whole country. The outcomes of the regional distribution are illustrated in subsequence. Similar to PV, Figure 30 shows a cross-scenario comparison of the regional breakdown of installed wind onshore capacities for specific years (2030, 2040, 2050) over time whereas Figure 31 adds a comparison of how much of the identified potential is exploited in the final year 2050.

Solar PV: Regional distribution according to modelling and comparison with identified potentials

Figure 28: Cross-scenario comparison of the distribution of cumulative PV capacities among regions of Ukraine by year (2030 at the top, 2040 in the middle and 2050 at the bottom)

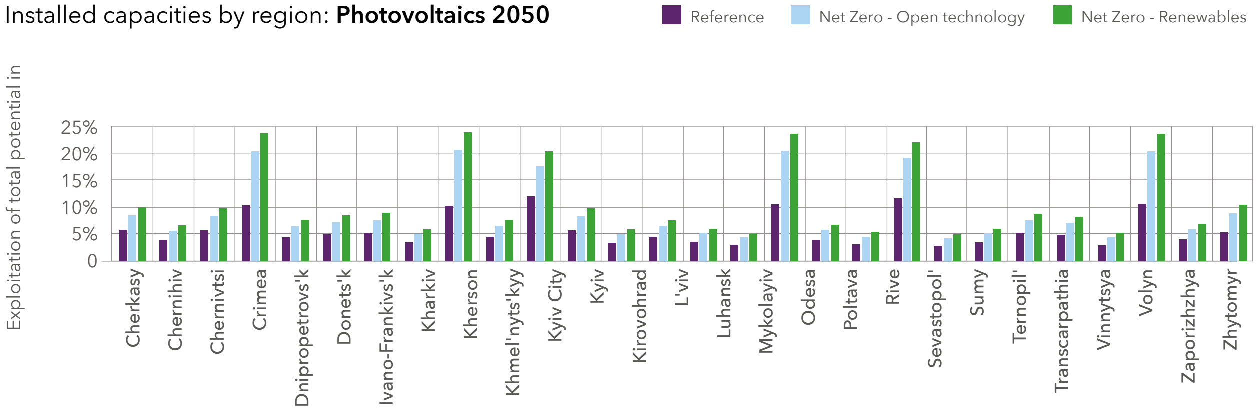






Source: own assessment

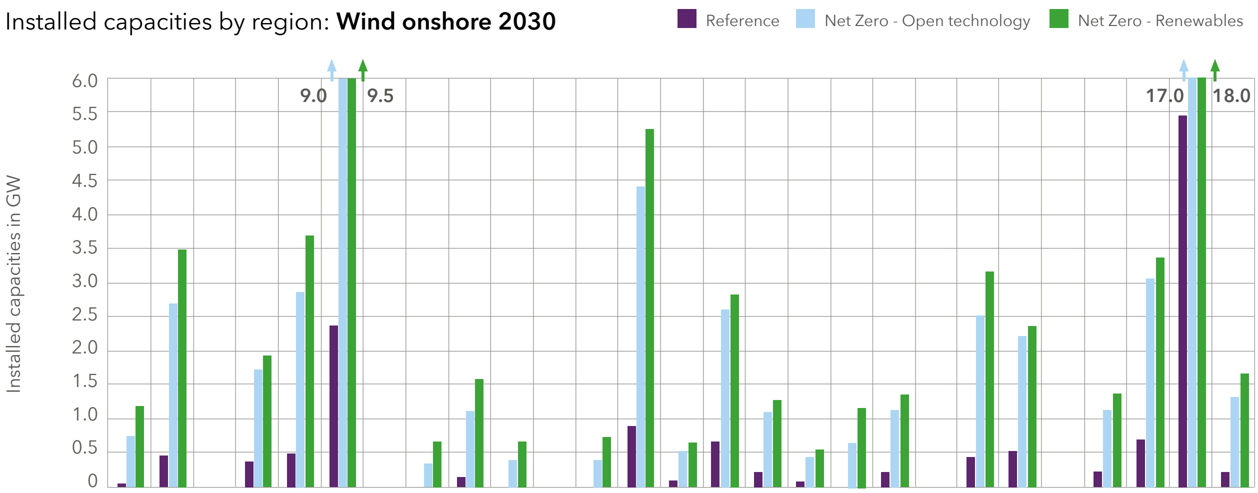
Figure 29: Cross-scenario comparison of the exploitation of technical potentials for solar PV at regional level in Ukraine by 2050



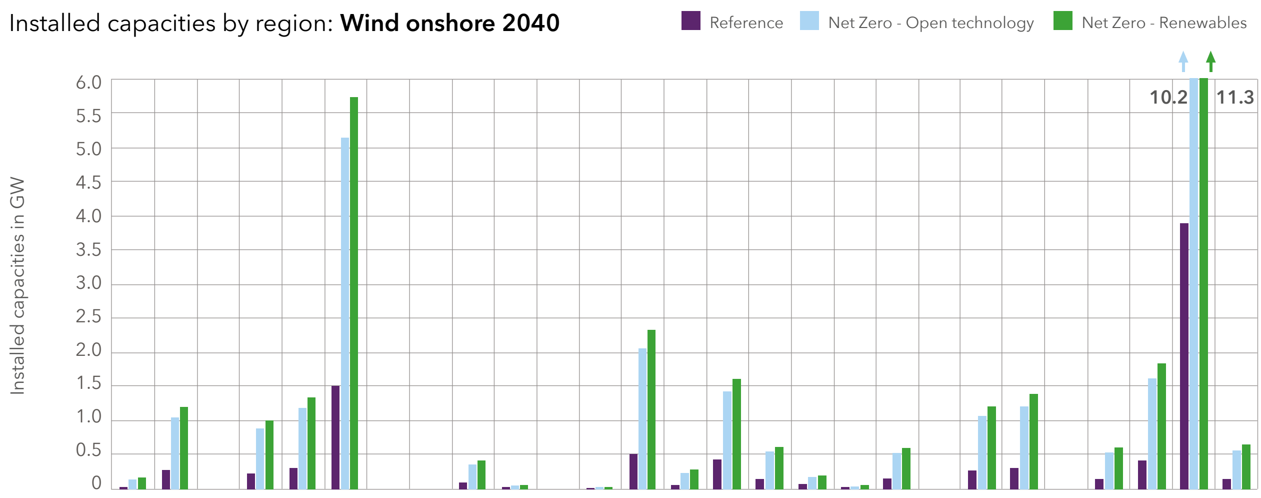
Source: own assessment

Wind onshore: Regional distribution according to modelling and comparison with identified potentials

Figure 30: Cross-scenario comparison of the distribution of wind onshore capacities among regions of Ukraine by year (2030 at the top, 2040 in the middle and 2050 at the bottom)



Source: own assessment



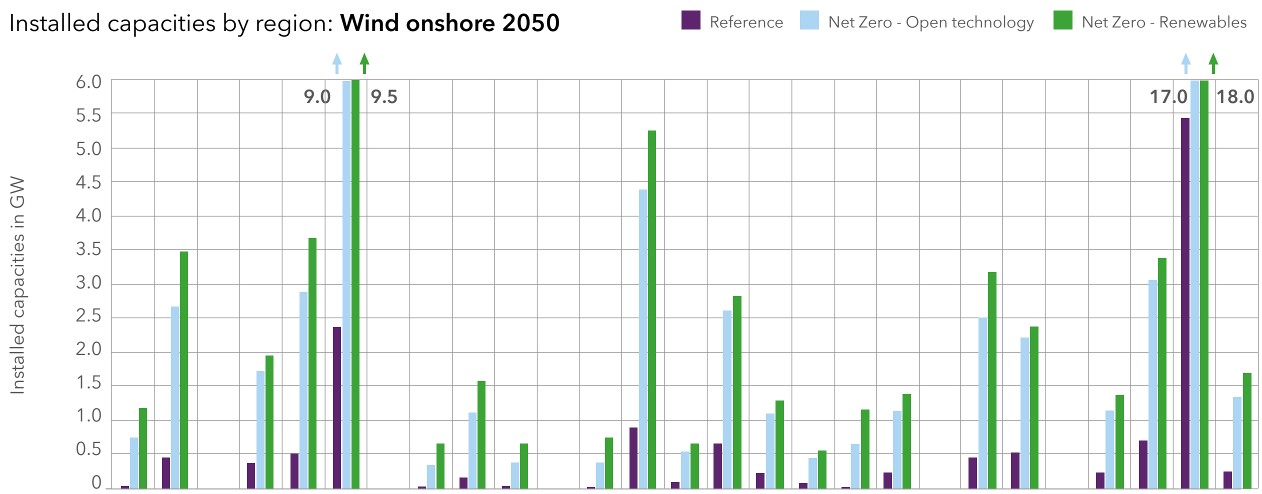


Figure 31: Cross-scenario comparison of the exploitation of technical potentials for wind onshore at regional level in the Ukraine by 2050. Source: own assessment