Unlocking Ukraine's Hydrogen Opportunity: A Roadmap

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Acknowledgements

This study was prepared by the Energy Technology Policy (ETP) Division of the Directorate of Sustainability, Technology and Outlooks (STO) of the International Energy Agency (IEA). It was directed by Timur Gül, IEA Chief Energy Technology Officer, and developed under the guidance of Uwe Remme, Head of the Hydrogen and Alternative Fuels Unit.

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Thanks go to Christoph Winkler, Heidi Heinrichs, Jochen Linssen and Detlef Stolten from the Jülich Systems Analysis (Forschungszentrum Jülich) for their collaboration on the analysis of levelised cost of hydrogen.

The report was edited by Lizzie Sayer and its publication was co-ordinated by Astrid Dumond from the Communications and Digital Office (CDO). Isabelle Nonain-Semelin handled the final production. Poeli Bojorquez provided the graphic design support. Gaëlle Bruneau supported with web design.

Many government officials and international experts provided input and reviewed a preliminary draft of the report. Their comments and suggestions were of great value. They include: colleagues from the Ministry of Energy of Ukraine, Borys Dodonov (Kyiv School of Economics); Vasyl Doronin (Ukrainian Hydrogen Association); Iryna Doronina (Technical University Munich); Nazar Kholod (Pacific Northwest National Laboratory); Cyriac Massué (Federal Ministry for Economic Affairs and Climate Action, Germany); Leander Muller (Technical University Munich); Roland Schulze (European Investment Bank); Jesse Scott (Observer Research Foundation); Oleksiy Tatarenko (RMI).

The individuals and organisations that contributed to this report are not responsible for any opinions or judgements it contains. All errors and omissions are solely the responsibility of the IEA.

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Executive summary

More than 3 years of war in Ukraine have left their mark on the energy sector. In the power sector, nearly 80% of the thermal generation and about two-thirds of the hydropower capacity have been damaged or destroyed, leading to a power deficit equal to about one-third of peak demand. Hydrogen demand was nearly 1 Mtpa before the war, predominantly for ammonia production, with only about 40 ktpa from refining. However, assets have since been damaged or occupied and demand has plunged by almost 80%. Steel output, which represents a potential new application for hydrogen, has dropped by almost two-thirds.

Massive capital mobilisation is needed for reconstruction, but there is also a lot of bilateral support flowing to Ukraine. The cost of reconstruction was estimated to have reached USD 524 billion by December 2024. Transport infrastructure is estimated to require nearly USD 78 billion, industry and commerce another USD 64 billion, and core energy assets USD 68 billion. At the same time, by December 2024, nearly USD 430 billion of bilateral support had been committed for Ukraine, two-thirds of which has already been allocated. About half is for purposes other than humanitarian or military. The European Union and its member states have been the largest donors.

Hydrogen could create jobs and revenue, but would require massive investment. Every 2.5 Mtpa of hydrogen production could generate annual revenues of USD 18-22 billion from exports and create up to 100 000 jobs, though nearly 70% of these jobs would be temporary. Deployment at this level would require an investment of USD 85-90 billion just for electrolysis and renewables. Tackling the cost of capital is key, since this investment would carry interest payments of USD 165-175 billion with a cost of capital at 15%, which could fall to be USD 55-60 billion at 5%.

The macroeconomic environment presents challenges. At a macro level, nearly 15% of the population has left the country or been internally displaced, impacting labour availability for hydrogen projects. Inflation has fluctuated between 12% and 26%, and central bank interest rates have been at 10 to 25% affecting the cost of capital for hydrogen projects. In 2024, fiscal deficit reached nearly a quarter of Ukraine's GDP (USD 180 billion) and public debt was equal to nearly 100% of GDP.

Country risk and its impact on the cost of capital is the most important hurdle for hydrogen projects. Low-emissions hydrogen is a nascent sector, and scale-up faces barriers including the need to find off-takers to secure finance, the cost gap in comparison to production from unabated fossil fuels, and infrastructure availability in certain locations. In Ukraine, however, country risk determines the overall cost of capital. Even before Russia's full-scale invasion, the cost of capital was already above 12% for renewables, and even higher for hydrogen projects given the sector-specific risks. The country has already defaulted on its international debt and its government bonds rating is the lowest.

Ukraine's proximity to the European Union puts it at an advantage compared to other countries aiming to export to the region. Ukraine shares a border with the European Union and is already interconnected with multiple gas pipelines. This proximity would enable low-cost transport for hydrogen and its derivatives by pipeline, which is cheaper than transport by ship. The short distance also allows transport by rail for outputs such as steel products. This could make a difference when comparing the delivered cost of products from different regions.

Large growth in demand for hydrogen in the European Union and the Carbon Border Adjustment Mechanism (CBAM) could trigger deployment. Hydrogen demand in the European Union was nearly 8 Mtpa in 2023, which could increase to 15-73 Mtpa by 2050 depending on the evolution of different technologies and applications for hydrogen. Legislation already in place will spur demand for low-emissions hydrogen, and the CBAM could help further close the cost gap with unabated routes. Hydrogen, fertilisers (ammonia) and steel are all covered by the CBAM. Before the war, one-third of Ukraine's steel exports were to the European Union. Completion of the EU accession process would mean that the EU Emissions Trading System (ETS) would also provide an incentive for low-emissions domestic production.

Ukraine has vast gas infrastructure, but further efforts to assess its use for hydrogen are needed. Existing gas interconnection pipelines to the European Union have a technical capacity equivalent to nearly 33 Mtpa. Some of the capacity might be used for biomethane, but it is large enough to potentially accommodate hydrogen and biomethane. Ongoing efforts to develop hydrogen corridors through Slovakia to Germany and Austria currently need off-takers to move forward. In addition, Ukraine could store about 2.4 Mtpa of hydrogen in existing underground gas sites. Both pipelines and underground storage have strong potential, but more assessment of their suitability for hydrogen is needed.

Ukraine has a rich renewable potential; its wind and solar technical potential is 1 300-2 300 TWh/yr. If this potential was used for hydrogen production, this would be equivalent to 18-38 Mtpa. The average renewable resource quality in Ukraine is better than in Germany, which represents a large share of EU hydrogen demand and is expected to continue to do so in the future. This could translate into a cost advantage once the cost of capital comes down. However, nearly half of the renewable potential is in oblasts that are either currently occupied or contaminated with land mines. Water availability might pose difficulties in regions with the highest potential, given the combination of low water supply and competing uses.

Efforts in the short term should focus on renewables. This is first and foremost because of the need to restore energy supplies. But there would be positive spillover effects to hydrogen, as this would serve to de-risk renewable deployment, which is a key cost component for renewable hydrogen production. It would also enable a progressive de-risking approach for different parts of the supply chain, allowing investors to gain confidence with renewables instead of trying to finance integrated projects from the start.

Addressing the high country risk premium is critical in the short term. This could leverage the bilateral support announced to mobilise capital, but it could also build upon grants from development finance institutions. Coverage against war risk in Ukraine is already provided by the World Bank. There are also examples of national development finance institutions and Export Credit Agencies providing political risk insurance. Part of this capital with preferential terms for the debt could also be used to deploy smaller projects that serve as lighthouse projects to build experience for subsequent deployment. A limitation for hydrogen is that this capital source is usually targeted at critical areas.

Hydrogen development requires a gradual approach, starting with assessment. Once the war ends, while initial actions will rightly focus on restoring energy security, there will be an opportunity to lay the foundations for the hydrogen market. Preparatory work is needed, covering aspects from the legislative framework to technical standards, capacity building, techno-economic studies, and suitability of the gas infrastructure, among other topics. This first stage would serve to inform next steps, but also provide time for a more stable environment to emerge, with greater visibility on the post-war economy.

Development finance might be sufficient to support demonstration projects, but private capital will be needed for large-scale deployment. Support for demonstration projects can build domestic experience that would be useful for the private sector and provide input for the government on regulation and potential. However, given the high investment needed for renewable hydrogen projects, large projects will require private capital. For this, investors need a long track record of projects that provides confidence on project cash flow and returns. This not only requires lighthouse projects, but sustained performance over time.

Introduction

Ukraine's energy sector has been severely affected by the Russian Federation's (hereafter, "Russia's") full-scale invasion. The power sector went from having a large capacity surplus before the war to a power deficit in 2024 due to Russia's attacks. This has focused attention on energy security and restoring the reliability of supply. Hydrogen demand from conventional applications in refining and ammonia has also plunged, falling 80%, with most of these assets in southern Ukraine, where the frontline and occupied areas are located. Overall economic damage from the war has been extensive, with reconstruction costs previously estimated by the World Bank at more than USD 0.5 trillion – three times Ukraine's GDP. Reconstruction in the energy sector represents about 14% of this.

Reconstruction offers an opportunity to build back better. In the energy system, this means strengthening energy security and reducing GHG emissions. The use of low-emissions hydrogen in industrial applications can provide the dual benefit of lowering GHG emissions and supporting the development of an export-oriented industrial base that can help to restore the fiscal balance. This is a long-term opportunity that will not happen overnight, but efforts need to start today to progressively build the experience required to enable such an industry in the future. Balancing these forward-looking enabling actions with the pressing short-term needs of restoring reliability of supply and satisfying the basic needs of the population will be crucial. Furthermore, low-emissions hydrogen is a relatively nascent sector that is itself facing challenges. The situation in Ukraine adds additional risks to deployment, which will require special attention to de-risking instruments and potential capital sources like international aid (in the early stages).

In this report, we focus on hydrogen production from renewables, given Ukraine's large potential and its higher quality when compared to the rest of Europe. Gas production in Ukraine is only just sufficient to satisfy domestic demand, so producing hydrogen from natural gas with carbon capture, utilisation and storage (CCUS) would mean that additional gas imports are needed. Ukraine also has vast experience with nuclear, which represents more than half of its electricity generation. However, no reactors have been built since 2004, there are no recent cost estimates, and – even with optimistic assumptions – hydrogen production costs from nuclear could be in the range of USD 3.6-5.3/kg H_2. This pathway is therefore only touched upon briefly.

The report identifies the actions required across four pillars (physical assets, regulation, financing and cross-cutting areas) and three time horizons (covering from 2 to 20 years), in order to provide a roadmap to enable the renewable hydrogen opportunity. These actions build upon best practices seen in other countries, but will require continual reassessment to adapt to the evolving situation in Ukraine.

This report complements recent IEA analysis for Ukraine. Ukraine's Energy Security and the Coming Winter focuses on the short term, laying out ten energy actions to reinforce national energy security, with a focus on the winter of 2024. The Empowering Ukraine Through a Decentralised Electricity System report provides a bridging perspective across time horizons, by identifying actions from now until 2030. This report complements existing analysis by providing a long-term perspective on the low-emissions hydrogen opportunity that is grounded in actions over the short and medium term, with a scope that extends beyond the power sector.

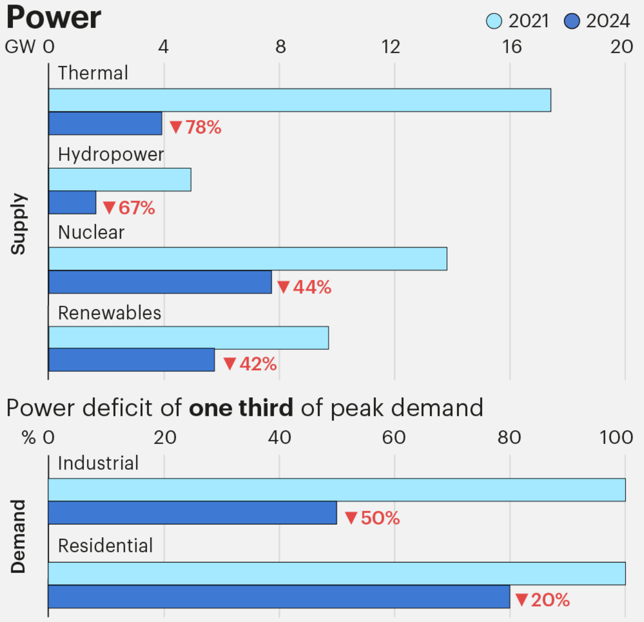
Taking stock of the effect of war

Highlights

- The assets of many hydrogen users have been destroyed since Russia's full-scale invasion of Ukraine in February 2022, causing demand to plunge by 80%. Ukraine's only operational refinery was severely damaged in 2022. Steel output has dropped by nearly two-thirds due to damage, occupation, logistical costs and electricity scarcity. Nevertheless, there is potential for future hydrogen demand in export-oriented sectors; prior to Russia's invasion, 40% of Ukraine's fertiliser output, 46% of its agricultural output and 67% of steel were exported.
- Power generation capacity has plummeted since Russia's invasion. Nearly 80% of the thermal generation and about two-thirds of the hydropower capacity have been affected, leading to a power deficit equal to about one-third of peak demand. This is despite industrial electricity demand having halved over the same period and residential demand falling by about 20%.
- Ukraine was a net gas importer prior to the invasion, and served as a transit country for gas from Russia to the European Union. In 2024, local demand was largely met with domestic production. The gas network's export capacity of 146 bcm stopped being used at the end of 2024, when Russia's transit contract expired. Ukraine has an underground gas storage capacity of 32 bcm.
- The weighted average cost of capital (WACC) was 12% for solar PV and onshore wind before Russia's invasion. The country risk premium is estimated at more than 15%, which could nearly triple hydrogen production costs compared to a mature market.
- Ukraine's population has fallen by 15% since 2022, with indications that 50-80% of people leaving the country are highly educated, and that three-quarters of employers are facing staff shortages. Inflation peaked at 26% in 2022 and, while it has since decreased to 13%, it could rise again with reconstruction funding. Domestic currency has been devalued by 50% since 2022. These wider macroeconomic risks will undoubtedly affect hydrogen projects.
- The cost of reconstruction in the energy sector has been previously estimated at USD 68 billion (40% of 2024 GDP), a fraction of the nearly USD 0.5 trillion required for reconstruction. Public debt reached nearly 100% of GDP at the end of 2024, with 80% in foreign currency. Ukraine is expected to have a fiscal deficit until at least 2033, and external finance will be needed. Foreign grants and development finance may be a source of public support for hydrogen projects, but will face competing needs for restoration elsewhere in the energy system.

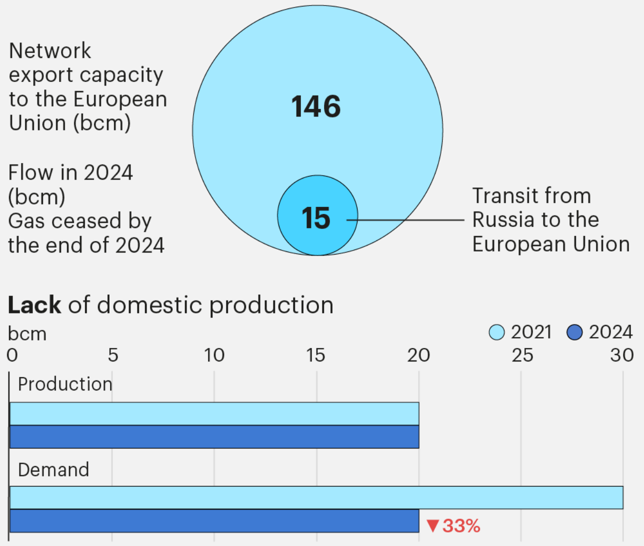
Taking stock of the effect of war

Power



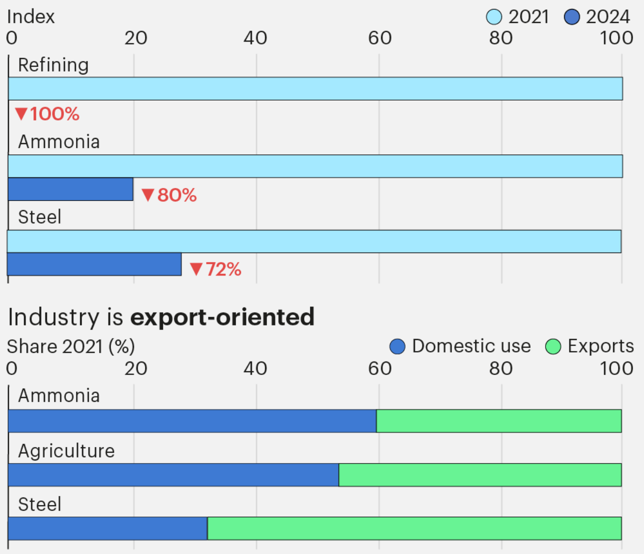
Gas

Large **existing** export **capacity**



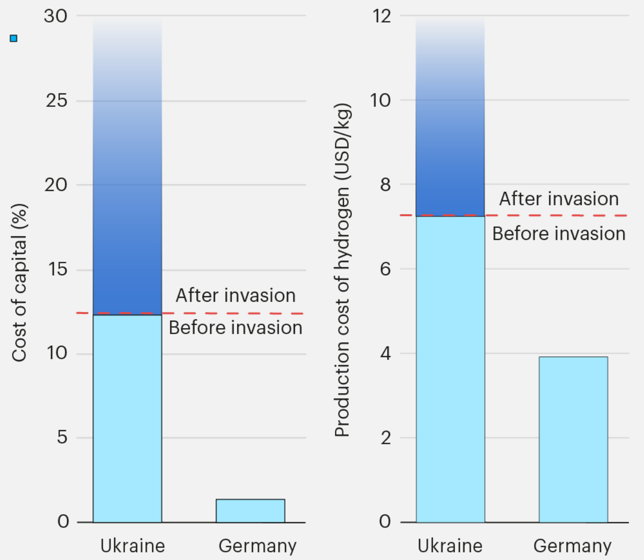
Hydrogen

Hydrogen **demand** has **plunged**

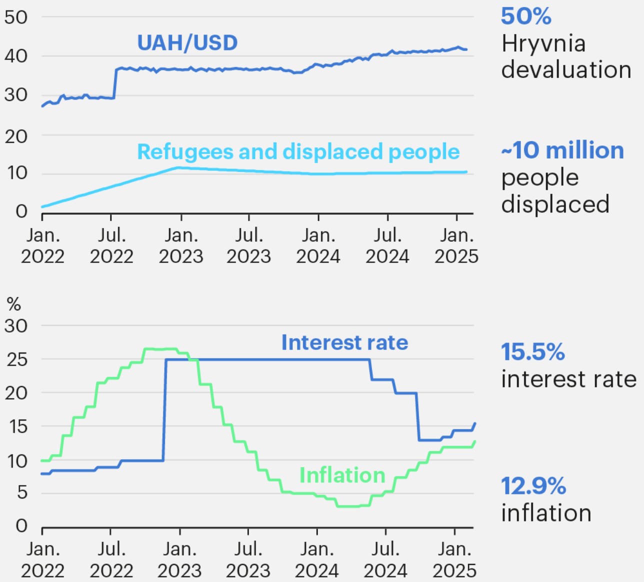


Cost of capital

3x cost premium due to high cost of capital

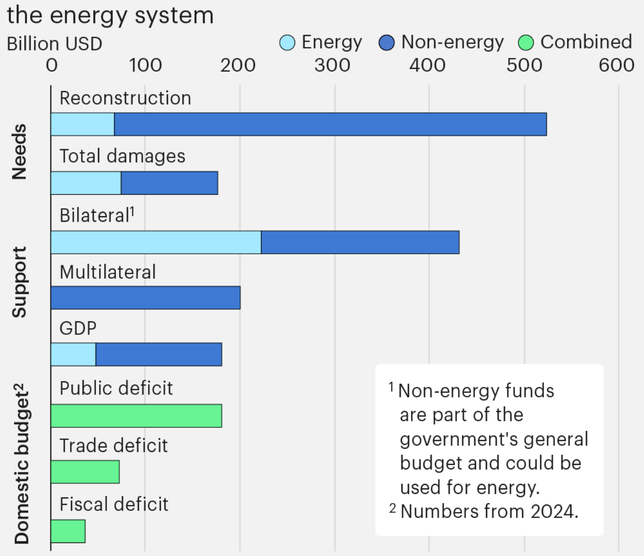


Macroeconomy



Finance

+50 Billion USD needed to reconstruct the energy system



Russia's full-scale invasion of Ukraine has had a profound impact on the country. This chapter takes stock of the effects related to hydrogen, including demand for existing applications like ammonia and refining, as well as considering how future applications like steel have been affected. It also looks at the power sector, given that renewable hydrogen production needs a mature and well-functioning power market, and gas infrastructure that could potentially be used for hydrogen, reducing costs. It considers the macroeconomy, which can affect the cost of capital, labour available for hydrogen projects, and project costs. Finally, it looks at the financial situation of the country, since this affects the capital sources that could be used for hydrogen projects, as well as the perceived risks that affect the cost of capital.

Hydrogen

Fertiliser, Ukraine's largest source of hydrogen demand, consumed about 1 Mtpa before Russia's invasion, but output has since fallen almost 80%. Natural gas demand for hydrogen production fluctuated between 3 and 6 bcm before the war (compared to a total gas demand of about 20 bcm), which would be equivalent to 675-1350 ktpa of hydrogen, with an average of roughly 1 Mtpa. Ammonia was produced in five facilities. One of them (Severodonetsk), representing nearly a quarter of the national technical capacity, was severely damaged during attacks in 2022 and taken out of operation. The remaining plants are operating at a largely reduced throughput and even periodically. Overall, total fertiliser output was down almost 80% by August 2024 compared to 2021.

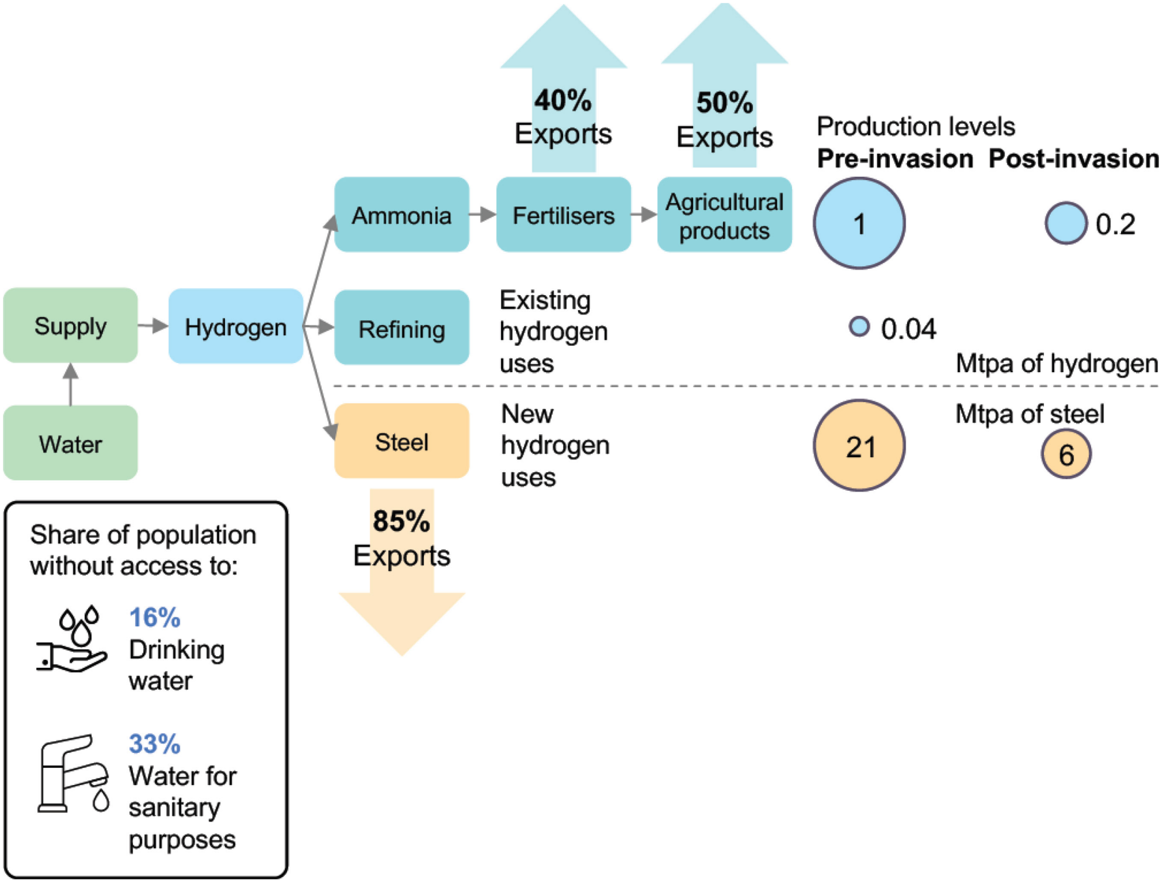
Exports of nitrogen-based fertilisers account for 40% of domestic production and 50% of agricultural output is exported, meaning domestic demand is not the primary driver of renewable ammonia. Both the fertiliser and agriculture industries are heavily export-oriented. Agricultural output has increased in the past two decades, using a larger share of domestic fertiliser production. In the early 2000s, fertiliser exports were approximately equivalent to 85% of domestic production, but by 2021 that fraction had decreased to 40%. In 2021, agriculture represented almost 11% of GDP and 41% of exports. The five largest exported products were sunflower oil, maize, wheat, rapeseed oil and barley. Nearly half of the production value was exported. In 2023, 40% less agricultural land was being farmed and the contribution of agriculture to GDP had decreased to 7%. Land mines and undetonated ammunition mean that about 30% of the land will require surveying before use for agriculture. In 2024, the availability of agricultural land has improved compared to at the beginning of the invasion, but is still 20% down from pre-invasion levels.

Hydrogen demand for refining was about 40 ktpa before Russia's invasion but has since come to a standstill. Domestic oil production was falling well before the war. Between 2006 and 2020, domestic oil production fell by more than 40%. Similarly, net crude oil imports had decreased by more than 90% from their peak in 2003. This led to multiple refinery closures, leaving only one refinery (Kremenchuk) in operation before 2022, with two-thirds of its supply coming from domestic production and the rest from Azerbaijan and the United States. Refining throughput was about 80 kb/d. Based on the global average of hydrogen consumption for refineries,[1] this would lead to a hydrogen demand of about 40 ktpa. In 2022, the refinery was attacked with missiles on four occasions, leading to extensive damage. Looking to the future, Ukraine's state-owned oil company, Ukrnafta, is aiming to increase domestic oil production by 50% by 2028.

Steel production has decreased by almost two-thirds since Russia's full-scale invasion. No pure hydrogen is used today in the steel sector in Ukraine, but this sector provides one of the largest opportunities for use of low-emissions hydrogen and exports. Before the invasion, steel was an important sector of the economy, representing nearly 10% of GDP and a quarter of the exports, as well as 15% of the national CO_2 emissions. In 2013, there were 12 plants operating with a capacity of 42 Mt and production of 33 Mt. After the occupation of the Donetsk and Luhansk regions, this had fallen to 9 plants and 21.4 Mt of production by 2021, with total exports of 15.7 Mt, of which nearly one-third was to the European Union.[2] In 2022, two plants in Mariupol representing nearly half of the national output were destroyed. The plant in Luhansk (5.4 Mt) is in occupied territory, and has been out of operation since 2022. By late 2024, there were only 6 plants left, with a production of 6 Mt (see Figure 1.1). This is still larger than domestic demand, which reached 3.3 Mtpa in 2023. Nearly two-thirds of the remaining production capacity uses blast furnaces, about 22% uses open hearth furnaces and 13% uses electric arc furnaces. Before the invasion, about two-thirds of the products were exported, and in 2023, exports still accounted for almost half of the production. The remaining steel plants are within 125 km of the occupied areas.

[1] This can vary widely depending on the refinery configuration. The sulphur content affects the hydrogen demand for hydrotreating, the share of heavy products and product mix affect the demand for hydrocracking, and a catalytic reforming unit can decrease the net hydrogen demand.
[2] The top 5 non-EU countries in 2021 were Türkiye, the United States, Russia, The People's Republic of China (hereafter, "China") and the United Kingdom, accounting for about a third of the exports. The other third is distributed among several countries.

Figure 1.1 Effect of Russia's full-scale invasion on hydrogen demand and water supply



Hydrogen production was primarily serving export-oriented industries prior to Russia's invasion and demand has plummeted ever since.

Iron ore exports in 2024 were 25% lower than in 2021 but iron ore is not a constraint on domestic steel production. Iron ore exports were 44 Mtpa in 2021. In 2022, Russia imposed a blockade on Ukrainian ports in the Black Sea, which led iron ore exports to decrease by nearly 45%. The volume of exports reached its nadir in 2023 with 17.7 Mtpa, but exports recovered in 2024 to nearly 34 Mtpa. These are only the exports: As a reference, the 6 Mtpa of domestic steel production would require about 10 Mtpa of iron ore,[3] meaning that if steel production recovers to its pre-war levels, iron ore production would be more than enough to meet the needs of the domestic market. 12% of Ukraine's iron ore reserves are in occupied territory.

The war has severely affected water supply, with potential implications for hydrogen production. Nearly a third of the national water resources (equivalent

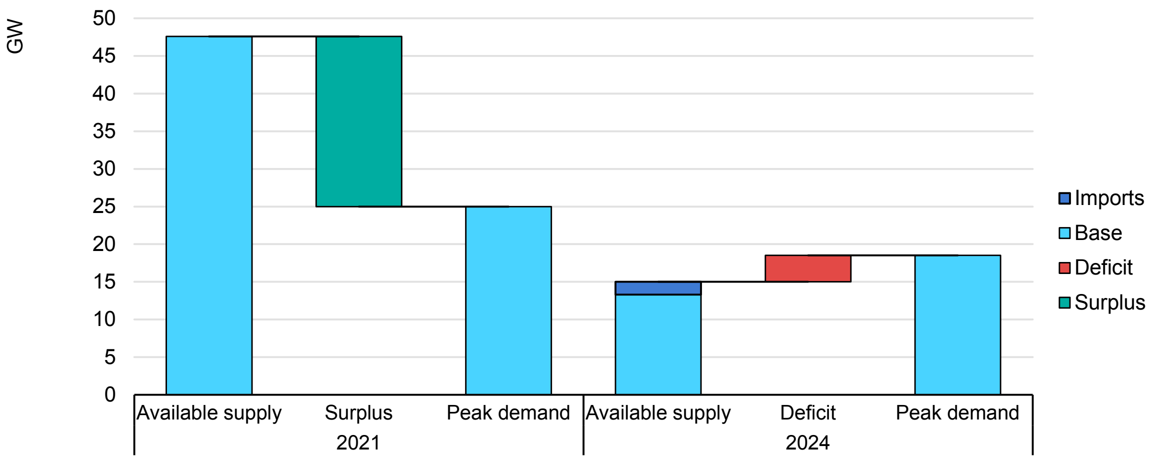
[3] Assuming an iron content of 62% which corresponds to the global average. This could be different for Ukraine, but it is used to give an order of magnitude.

to 55 000 million m^3) is held in reservoirs to ensure continuous water supply. In June 2023, the Kakhovka reservoir, with a capacity of 18 200 million m^3, was destroyed, with the reservoir losing 80% of its volume within a few days. The result was flooding in an area equivalent to about 2% of the country's land, a reduction in drinking water quality affecting about 6 million people, and restricted access to water for sanitary purposes affecting more than 13 million people. It also disrupted the flow through the Dnipro-Kryvyi Rih canal, which provided cooling water to power and industrial plants in the Dnipro and Zaporizhzhia oblasts (regions). Water supply networks, pumping stations, wells, and treatment plants have been severely affected in the Donetsk, Luhansk and Kharkiv oblasts.

Power

Russia's full-scale invasion has led to a drastic decrease in available capacity leading to power deficit. Before the invasion, the total installed generation capacity was 55 GW, but only 44 GW was available due to infrastructure being underfunded and outdated. Attacks during the war have affected nearly 80% of thermal generation capacity and about two-thirds of the hydropower capacity, leading to a sharp decrease to about 15 GW ahead of the heating season in 2024. In contrast, peak demand during winter can reach 18.5 GW, leading to a power deficit of at least 3.5 GW (see Figure 1.2), which could increase further with the continual attacks.

Figure 1.2 Balance between electricity supply and demand before and after Russia's full-scale invasion, 2021 and 2024



A surplus of nearly 23 GW pre-invasion had been replaced by a power deficit of 3.5 GW by the winter of 2024.

Renewables have been more resilient, aided by campaigns to repair war damage. In 2021, installed wind and solar capacity totalled about 9.5 GW. Since the beginning of the war there have been continuous attacks and subsequent reparation campaigns, which makes this capacity highly dynamic. For example, solar PV capacity was 8 GW in 2021, decreasing to 5.6 GW in 2024, but new capacity of 800-850 MW was installed in 2024. For wind, over 90% of the pre-war capacity of 1.7 GW has been occupied, damaged or destroyed, although capacity expanded by nearly 240 MW in 2023 and 20 MW in 2024. Thermal generation has seen large decreases with no new capacity coming online. Coal generation capacity stood at nearly 13 GW before the invasion. This was targeted by attacks, and only 3 GW remained in 2024. With this shift in installed capacity, the share of renewable generation was 13% in 2024, decreasing from 16% in 2021.[4] This is despite 30% of solar capacity being disabled or occupied in early 2024.

Ukraine has four nuclear power plants (13 GW), with the largest (5.7 GW) currently in occupied territory and in cold shutdown. Nuclear generated 55% of Ukraine's electricity before the war. All of Ukraine's plants use pressurised water reactors using Russian technology, and 12 of the 15 operating reactors were built in the 1980s.[5] Two of the operating plants are in the west of the country and two in the south. The largest plant (Zaporizhzhia), which has six reactors with a total net capacity of 5.7 GW, was attacked in March 2022 and has been under Russian control ever since. During this time, there have been several incidents with implications for nuclear safety, including the loss of the main cooling water supply (associated with the destruction of the Kakhovka dam), a large fire in one of the cooling towers, direct drone attacks and complete loss of off-site power. The International Atomic Energy Agency has stated that the Seven Pillars of nuclear safety have been fully or partially compromised in the past 2 years. The plant stopped generating electricity for the national grid in September 2022 and all the reactors transitioned to cold shutdown in April 2024.[6]

The interconnection capacity with the European Union has been expanded, reaching 2.1 GW in December 2024. Interconnection can provide resilience when generation is not enough. The Ukrainian system was well interconnected even before Russia's invasion, with 31 cross-border lines connecting to Poland (up to 1 210 MW), Hungary (650 MW), Slovakia (400 MW), Romania (400 MW) and Moldova (400 MW). In March 2022, the continental European electricity grid and the grids of Ukraine and Moldova were synchronised. Since then, exports to Ukraine have been steadily increasing, reaching 2.1 GW in December 2024, which is equivalent to 11% of the peak demand. There are no signs of this capacity

[4] The share of coal remained relatively stable at 19-20% and the share of nuclear generation increased from 58% to 60%.
[5] Two reactors in Khmelnytskyi have been under construction since 1989 (with postponements and cancellations in the meantime) with completion progress of 75% and 28%. Chernobyl has four reactors, of which three have been shut down for decommissioning and one was severely damaged in the nuclear accident in 1986 and is confined.
[6] In September 2022, five reactors were transitioned to cold shutdown and one was kept in hot shutdown for district heating.

being affected by the war; on the contrary, capacity has actually expanded since 2022 with the restoration of the interconnector with Poland having been completed in April 2023. There are already projects to expand the capacity with Slovakia (1 GW) and Romania (1-1.2 GW).

Industrial power consumption has halved, and residential demand has fallen by 20%. Large-scale centralised facilities have been targeted by attacks, leading to a sharp decrease in industrial demand. The decrease in the residential sector demand is a result of around 15% of the population fleeing the country since the beginning of the war. Energy efficiency has also contributed to the lower demand. Notably, a European Union-funded programme to replace incandescent bulbs with LED bulbs lead to a demand reduction of as much as 1 GW. The residential sector now represents the largest share of electricity demand, despite the 20% decrease.

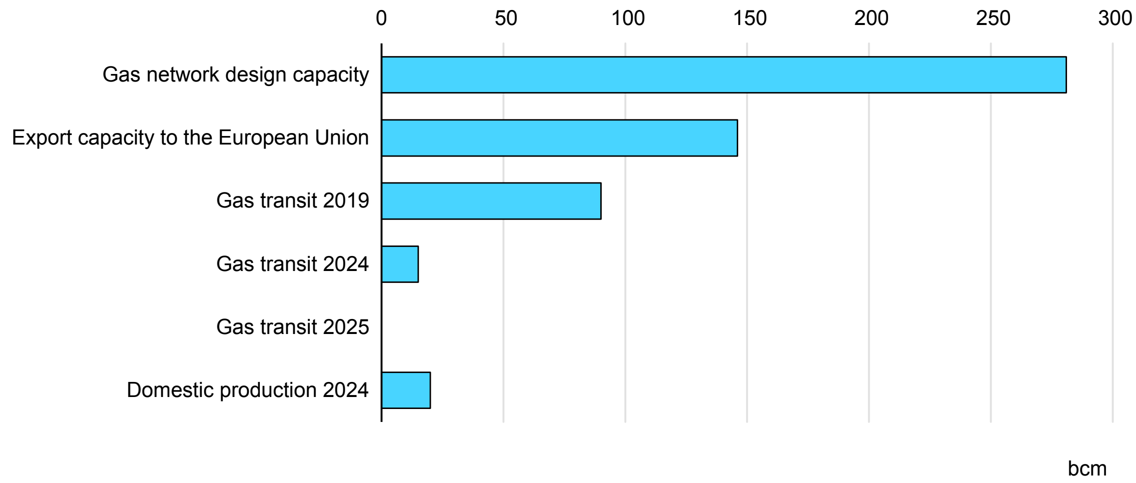
There is a carbon pricing scheme covering power and industry with a price level of less than USD 1/t CO_2. A carbon tax for stationary sources in the industry, power and buildings sectors has been in place since 2010 and covers nearly 40% of national GHG emissions. The price level was increased from USD 0.02/t CO_2 in 2019 to USD 1/t CO_2 in 2021, and in 2024, the price level was close to USD 0.77/t CO_2 (mostly due to fluctuation in the exchange rate). In 2021, Ukraine announced plans to launch an Emissions Trading System (ETS) in 2025 to complement the carbon tax. The effect of the EU Carbon Border Adjustment Mechanism (CBAM), as well as fiscal implications, will need to be considered when designing the domestic ETS and price targets. Ukraine is looking for a temporary waiver from the EU CBAM until the domestic ETS is in place.

Gas

Ukraine's vast gas infrastructure is being underutilised and has potential for repurposing for hydrogen. Ukraine has a gas transmission network of nearly 38 000 km with a design capacity of 281 bcm and an export capacity to the European Union of 146 bcm. In 2021, Russian gas exports to the European Union were 155 bcm, of which 40 bcm transited through Ukraine. Transit flows through Ukraine were as high as 90 bcm in 2019. In 2024, gas transit had shrunk to 15 bcm and following the expiration of Russia's gas transit contract with Ukraine, the flow declined to zero from 2025 (see Figure 1.3). The technical feasibility of repurposing gas pipelines to hydrogen is still unclear and requires further analysis. Ukraine has 13 underground storage sites with a working capacity of 32 bcm. Nearly 80% of this capacity is in Western Ukraine and more than 90% was still in operation in 2024. In 2023, the stored volume was 2.5 bcm, but this dropped to nearly zero in 2024. Russia repeatedly targeted underground storage sites in 2024. The storage capacity is being used by foreign traders to provide additional margin for the 2024/2025 winter season.

Ukraine is a natural gas importer with relatively small domestic gas production. Gas demand was shrinking even before the war, from 75 bcm in 2000 to 30 bcm in 2020.[7] In the decade prior to the invasion, domestic production had remained relatively stable at 20 bcm, so while the net trade improved over time, one-third of the gas demand was satisfied with imports (from Russia until 2014 and from the European Union afterwards). After the invasion, gas demand dropped by a third to 20 bcm and production fell by 6% to 18.5 bcm, with similar numbers expected for 2024. With this level of demand, domestic proved reserves would be enough to maintain production for 60 years, but additional investment would be needed to increase production in order to satisfy potential gas demand for hydrogen production. Ukraine imported its first liquefied natural gas (LNG) cargo from the United States in December 2024 and imported 0.8 bcm in February-March 2025 from the European Union (by pipeline). Ukraine's government expects that imports of at least 1 bcm will be needed in 2025.

Figure 1.3 Capacities and flows of the gas system before and after Russia's full-scale invasion



IEA. CC BY 4.0.

Ukraine's gas system has an export capacity of 146 bcm to the European Union, which is now idle after gas transit through Ukraine from Russia stopped in 2025.

Cost of capital

Cost of capital can be decomposed into cost of debt and cost of equity. Both can be further split into risk-free rate (the interest rate paid for securities in a low-risk market, usually the United States), the country risk (which is composed of political and macroeconomic risks), the sector risk (e.g. renewables, steel), and the technology risk (related to technology maturity, supply chain, construction and operation). For the cost of equity, one common input parameter is the volatility of

[7] These are annual values. Winter demand was 2-2.8 times higher than gas production pre-war.

the equity market, which is usually approximated with the trends of the overall stock market index. However, in the case of Ukraine, the stock market has been closed since February 2022, so there is no indication of market volatility. This section touches upon how recent events have affected some of these factors.

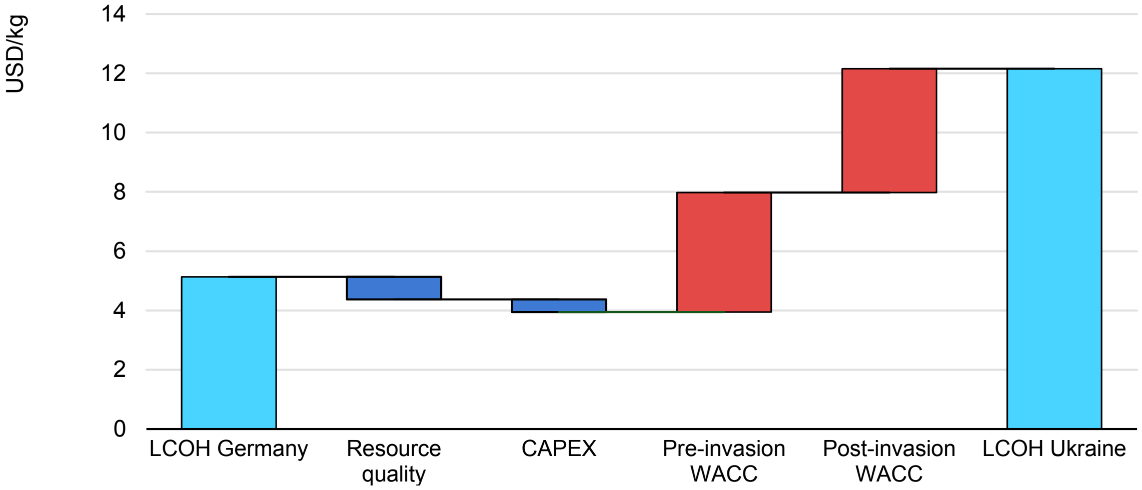
The WACC was already above 10% in real terms before Russia's full-scale invasion with significant effects for the cost of hydrogen. The International Renewable Energy Agency (IRENA) reported a WACC of almost 10% for solar PV and onshore wind in real after-tax terms for 2021, based on real project data with an average of 12.2% for 2019-2021.[8] Considering that inflation was 10% in 2021, this would be equivalent to 20% in nominal terms. In comparison, the WACC for both solar PV and onshore wind in a mature market like Germany was 1.3% in 2021. These values are for renewables, and hydrogen projects notably carry additional risks related to technology, market maturity and offtake, among others. These are considered as a fixed premium in Figure 1.4, but could be expected to weaken the case for hydrogen production in Ukraine, given the current lack of domestic offtake and limited experience with the technology. This WACC differential could lead to a 55% higher cost of renewable hydrogen production when compared to Germany,[9] which makes the case for hydrogen deployment more difficult. In absolute terms, this means an increase from USD 5.1/kg to USD 8/kg (see Figure 1.4). This is significant, considering that the production cost for hydrogen from unabated gas in Europe was at around the same level – USD 3/kg[10] – in December 2024. The conditions that enabled such a low WACC for Germany, including low interest rates, might not return any time soon. Nevertheless, this shows the wide gap between Ukraine and a potential market for its hydrogen exports, such as Germany. Most of this differential is driven by the country risk, which was already high before Russia's full-scale invasion. If Ukraine can reach the same WACC level as targeted markets (e.g. through development finance, discussed in Chapter 3. "Unlocking the opportunity – A roadmap for action"), then the levelised cost of hydrogen could be lower.

[8] Another study from 2019 estimates a similar value using a capital asset pricing model. The WACC estimated is 16% in nominal terms. Given that inflation was between 2.7% and 7.9% in 2019-2020, this would lead to a value of about 10-11% in real terms.

[9] Assuming 100% onshore wind, which has the largest potential in Ukraine, and a capacity oversizing factor of two for the electrolyser.

[10] With a gas price of EUR 45/MWh, EUR/USD of 1.05, efficiency of 69% and CAPEX of USD 1280/kW.

Figure 1.4 Contributing factors to levelised cost of hydrogen production difference between Germany and Ukraine, 2023



Notes: LCOH = levelised cost of hydrogen; WACC = weighted average cost of capital. Assuming 100% production from onshore wind, which represents the largest share of Ukraine's renewable potential (see Chapter 2. "The hydrogen opportunity"), CAPEX for onshore wind in Germany of USD 1 750/kW and USD 1 373/kW for Ukraine. CAPEX of USD 2 160/kW for the electrolyser, and capacity factors of 29% and 32% for onshore wind in Germany and Ukraine, respectively. Electrolyser capacity is not optimised and assumed to be double the capacity of the renewable capacity. WACC for Germany assumed to be 4.2% taking the last real point available (1.3% in 2021) and correcting for risk-free interest rate change (based on US 10-year treasury bonds). For Ukraine, WACC is 12.2% pre-invasion and 25% post-invasion. WACC premium of 2% points for electrolysis.

Even prior to Russia's invasion, the cost of hydrogen production in Ukraine was 50% higher than in Germany, and this gap has now widened further.

Government bonds have the lowest credit rating, and the country risk is at least 15%. One indicator of the country risk is the spread between the domestic bond yields and the yield of a mature market (such as the United States). In 2021, the yield of the 3-year government bonds[11] in Ukraine was 13-13.5%, while the US Treasury bonds of the same maturity were 0.2-0.4% during the same period. In the last quarter of 2024, the yield of the Ukrainian bonds was 24%, while the US Treasury bonds were at 3.5-4%. Even when correcting for inflation, which in 2024 was 70% higher in Ukraine than in the United States, the spread has significantly widened due to the war, and the country risk premium is still well above 15%. Other estimates using USD and EUR found yield spreads of more than 23% when the full invasion started. Another indicator of country risk is the credit rating, which is continuously assessed by credit rating agencies[12] and revised when there are significant events that could affect the ability of the country to repay its debts. This rating can be approximated to a country risk premium based on the credit default spread for country bonds that are traded. Ukraine's rating has been deteriorating for the past 25 years, and in 2024, Ukraine partially defaulted on its debt, which led to a downgrade of its rating. Even for the lowest

[11] This is the maturity with the largest share of domestic debt in the coming 10 years.
[12] The three largest are Moody's, Standard & Poor's (S&P) and Fitch.

rating (which is still better than the rating Ukraine has today), the country risk premium would be equivalent to about 15%. Country risk is not the only factor to consider for the cost of capital; physical risk to assets and uncertainty about business continuity could also lead to large WACC increases even after the war ends.

The cost of capital for private companies might be higher than for the government. The credit rating of the private sector has also deteriorated during the war. DTEK, Ukraine's largest renewables developer, was downgraded by Fitch in September 2024 to a status of restricted default. There is also a risk gap between the private sector and the government: In the case of government debt, international finance might help with repayment, but this is not an option for private debt, increasing the risk and the interest rates.

Debt accumulation and a retroactive tariff cut for renewables has led to lower confidence from investors, potentially translating into a higher cost of equity. A feed-in tariff (FiT) scheme ("Green tariff") was introduced in 2009 to run until 2030. A publicly owned enterprise acted as a guaranteed buyer with rates fluctuating from EUR 0.46/kWh to EUR 0.15/kWh until 2019. The solar capacity expanded quickly from about 1.5 GW in 2016 to nearly 8 GW in 2021 (with the largest expansion taking place since 2019). However, the scheme was not financially sustainable, with the guaranteed buyer failing to pay the generators. In 2020, the Parliament approved a retroactive cut of up to 60%.[13] The total debt under the scheme was nearly USD 475 million in 2024 and only 55% of the payments for 2022 and 2023 were disbursed. There is little clarity on a robust repayment plan, which has affected confidence in the renewable sector, and the resulting uncertainty extends to renewable hydrogen. Even when repaid, this might be reflected in a higher cost of capital demanded by investors. In January 2025, Ukraine launched auctions for solar PV and wind, signalling the move away from FiT.

Macroeconomic factors

This section reviews the macroeconomic factors shaping the country, including population and fiscal budget, and explores how they can affect hydrogen development. The central bank interest rate gives an indication of the cost of debt, although debt could come from sovereign capital at early stages when the cost of local debt is high.

Population declined nearly 20% in the post-Soviet era and another 15% after Russia's full-scale invasion. Ukraine had a peak population of nearly 52 million people in 1993, declining to 44.3 million in 2021. By February 2025,

[13] The lower bound was 2.5%. The rate depended on the technology, plant size and commissioning date.

6.9 million people had fled the country and another 3.6 million people had been internally displaced. The labour force decreased nearly 14% from about 17.7 million people in 2020 to 15.2 million in 2024. Evidence from 2022 (at a point when 4.7 million refugees from Ukraine had registered in the European Union) shows that in most EU member countries, 50-80% of the refugees were highly educated. A domestic survey in 2024 indicated that almost three-quarters of local employers are facing staff shortages. Some of the (relevant) vacancies that are proving most difficult to fill were for managers, engineers and business analysts. This may limit the availability of qualified staff to design, construct and operate hydrogen projects.

The war has caused a shortage of engineers and people with technical education. In a survey conducted in 2023 across 60 companies working in different fields, one-third reported that lack of candidates was their biggest recruitment problem, and almost one-quarter reported candidates having insufficient qualifications. Respondents also stated that the knowledge and skills of higher education graduates do not meet business needs. Electrical and chemical engineers were identified among the professions with the largest shortage at that time, with a shortage of mechanical engineers expected around 2028. The largest need for technicians was in industry, including steel, chemicals, mining and energy. The workforce is currently male-dominated, with men representing 58%, 65% and 71% of the workforce in the processing, energy, and mining industries, respectively.

Inflation had fallen to 13% in early 2025 from a peak of 26% in 2022. Before the war, inflation was at an average of 2.7% in 2020. In 2022, spikes in the prices of energy and food led inflation to increase to 26%. This came down to 13% in January 2025, which is still well above the 5±1% target of the central bank. The central bank expects inflation to increase further to 15% in 2025 and to reach 8.4% by the end of the year. For hydrogen projects, inflation could raise the costs of construction materials and labour during the construction phase, and could also affect the unemployment rate, with knock-on effects for the labour force available to work on hydrogen projects. Inflation can also make it more difficult for project developers to repay debts, if the nominal interest rates are based on a higher inflation rate that does not then materialise.

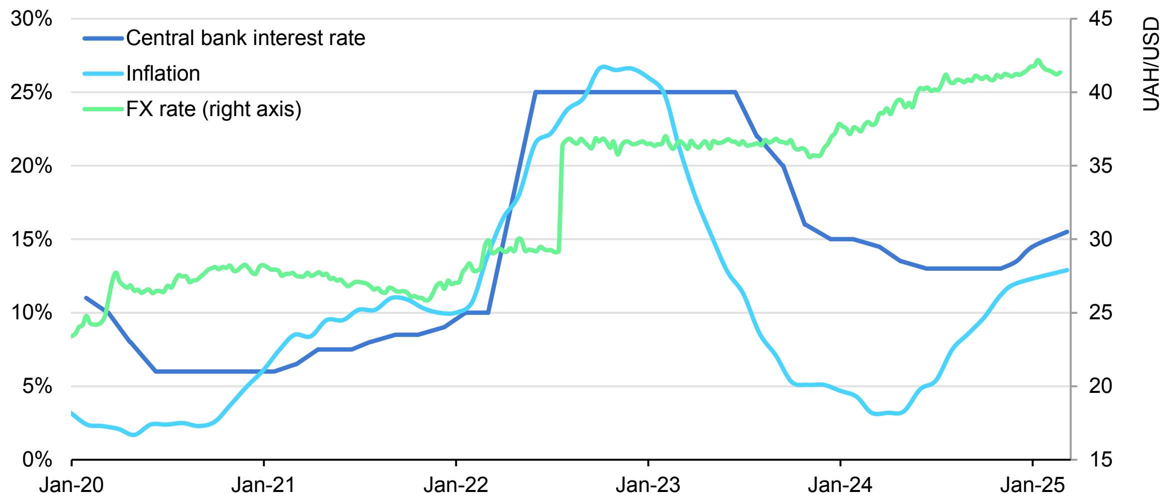
Central bank interest rates in 2024 were roughly double the levels before the invasion. In 2021, the central bank interest rate (known as the Key Policy Rate [KPR]) was between 6-9%.[14] In June 2022, as a response to high inflation, the central bank sharply increased the KPR from 10% to 25%. Inflation came down to 5% in the last quarter of 2023, which prompted KPR cuts reaching a level of 14.5% by March 2025. This is relevant to hydrogen projects because the KPR defines the interest paid by commercial banks, which in turn affects the loans made by

[14] 6% at the beginning of the year with 7 changes in the year to reach 9% at the end of the year.

those banks (in this case to energy or hydrogen projects). This makes the cost of debt higher. While the early stages of hydrogen development are expected to rely more on equity (due to the higher risk), and domestic commercial banks might be less involved at this stage (due to unfamiliarity with the business), it might still be relevant during later stages, depending on how long inflation remains high. It could also be relevant given the potential inflationary impact of additional capital flowing to the country for reconstruction efforts in other areas.

The domestic currency (Ukrainian hryvnia, UAH) has been devalued by about 50% since Russia's invasion. A peg to the US dollar was introduced at the beginning of the war (29.25 UAH per USD). Due to the widening gap between the official and the shadow rate, the central bank devalued the hryvnia by 25% in July 2022 but decided to keep the peg. In October 2023, the peg was substituted with a managed floating and the currency has continued to depreciate since then (see Figure 1.5). The relevance of this parameter as a currency exchange risk to the project is twofold. First, in the case that an investment is made by a foreign company in a hard currency (USD or EUR) while the revenues are in UAH. This could happen in the early stages of market formation, when infrastructure has not yet been developed, and demand is domestic. Second, there may be a positive effect in cases where the debt for the project comes from domestic bonds issued in UAH and (part of) the revenues come from exports. While there are known ways to manage this risk, it could still translate into a risk premium that is reflected in the WACC.

Figure 1.5 The effects of Russia's invasion on the central bank interest rate, inflation, and the Ukrainian hryvnia exchange rate to US dollars, 2020-2024



Sources: IEA analysis based on data from the National Bank of Ukraine.

The central bank interest rate is double pre-invasion levels and Ukraine's currency has depreciated by 50%, while inflation has now returned to pre-invasion levels.

Sovereign-guaranteed bonds were restructured in September 2024 to reduce short-term payments. The restructuring was for a total of USD 20.5 billion. The upfront capital was reduced by 37% and debt servicing costs until 2033 were reduced by 77% (i.e. all the payments were delayed, allowing the country to recover and avoid the payment burden negatively affecting the fiscal situation). This was done by having a scaling interest rate of 1.75-3% in 2025-2027, increasing to 7.75% after 2034. These interest rates might have been affected by the simultaneous deployment of funds from the Extended Fund Facility of the International Monetary Fund (IMF). While the restructuring is understandable in the current context, it highlights an uncertainty for foreign bonds related to the length of the transition period following the end of the war, during which time such lower interest payments might be needed. Along the same lines, the Group of Creditors of Ukraine (comprised of all G7 countries except Italy) agreed to delay all interest payments until 2027.

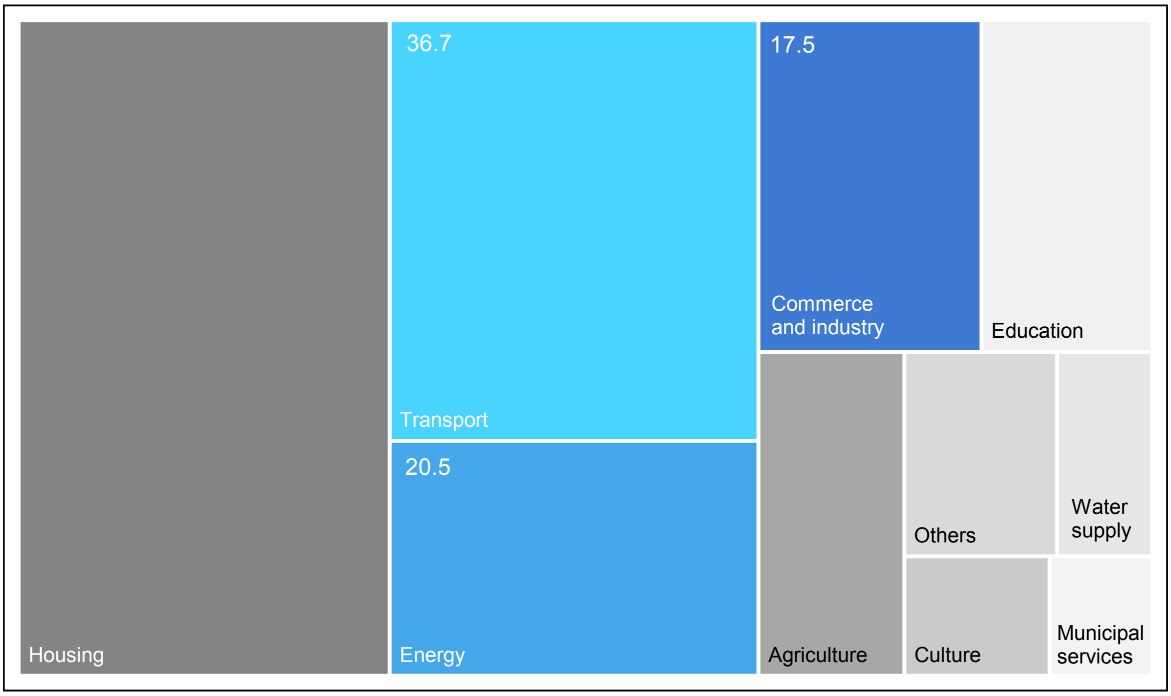
Finance

The purpose of this section is to understand some of the capital flows needed to reconstruct the country, with emphasis on the energy sector. This will be useful as reference for the potential revenues and investment needs for the hydrogen sector discussed in Chapter 2 ("The hydrogen opportunity").

Total damage[15] in the first 2 years of the war amounted to USD 176 billion, of which USD 55 billion was to energy-related assets. By December 2024, the bulk of the damage has been to housing and buildings, amounting to nearly USD 58 billion (see Figure 1.6). This is followed by transport infrastructure (including roads, ports, bridges) with USD 37 billion. Industry and commerce has experienced damage of USD 17.5 billion. Direct damage to energy assets amounted to USD 20.5 billion, and if indirect financial losses are included, total damage reaches USD 56 billion. An additional USD 65 billion of damage to natural ecosystems like forests, wetlands and biodiversity has also been estimated. Some of the most notable damage to energy assets was the destruction of the Kakhovka hydropower plant in June 2023.

[15] Damages are direct costs of destroyed or damaged physical assets and infrastructure, valued in monetary terms. Reconstruction needs are costs for repair, restoration, and reconstruction, considering a build-back-better premium and factors such as inflation, higher prices due to volume of construction and higher insurance, among others.

Figure 1.6 Economic damage caused by Russia's full-scale invasion of Ukraine by sector, December 2024

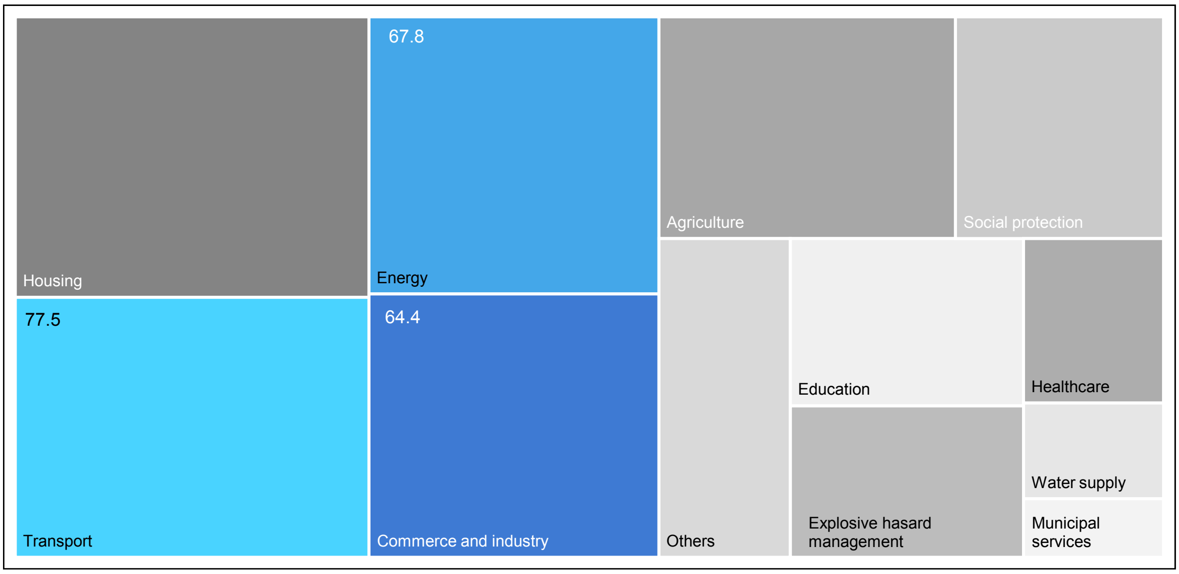


Notes: Damages assessed following the World Bank's methodology and using data collected by local authorities since Russia's invasion. To estimate the value of damaged or destroyed assets, average values are calculated based on data from the State Statistics Service with adjustment factors applied according to the level of damage to the assets.
Source: IEA analysis based on data from the World Bank Group (2025).

The cost of damages caused by Russia's invasion of Ukraine was estimated at USD 176 billion by December 2024.

By December 2024, reconstruction needs were estimated at USD 524 billion, nearly three times Ukraine's GDP in 2024. Like for damage costs, the largest capital needs are in the housing sector, with the World Bank estimating capital needs of nearly USD 84 billion (see Figure 1.7). Transport infrastructure (including ports and roads needed for hydrogen projects) comes second, with nearly USD 78 billion. Industry (together with commerce) requires USD 64 billion, and core energy assets require USD 68 billion. This has increased in the past couple of months. By August 2024, the needs for the energy sector were USD 50.5 billion for a complete restoration. As a comparison, Ukraine's GDP in 2024 was estimated to be about USD 180 billion.

Figure 1.7 Total capital needs to repair, restore and reconstruct assets in Ukraine by December 2024



Source: IEA analysis based on data from the World Bank Group (2025).

Total capital needs for reconstruction had reached USD 524 billion by December 2024.

Public debt could reach nearly 100% of GDP in 2024 with nearly 80% in foreign currency. In 2021, public debt was about 54% of GDP. Government borrowing has been increasing ever since the financial crisis in 2008, with public debt going from 12% in 2007 to a peak of 70% in 2016. In absolute terms, public debt had reached nearly USD 155 billion by November 2024, having increased by nearly 60% since the beginning of 2022. Nearly two-thirds of this debt is foreign and almost 80% is in foreign currency. This means that inflation and currency exchange rates could affect the repayment of this debt, compromising the credit rating of the country. This could affect the cost of capital for hydrogen projects due to country risk and the cost of debt (through the KPR). Foreign reserves have been relatively stable since 2023.

Goods trade deficit reached USD 40 billion over 2022 and 2023. Exports nearly halved after the invasion, led by significant drops in steel and metals (the main export), ore minerals, and agricultural products. This has led to a trade deficit of about USD 2-3 billion per month, which has been widening over time as more goods are imported. The IMF expects a trade deficit of USD 30-40 billion to persist until at least 2033. In 2024, international reserves have fluctuated around USD 40 billion, which would cover roughly six months of imports. The relevance this has for hydrogen is that low-emissions steel and renewable ammonia could help bring down the trade deficit, since they made up the bulk of exports before the war.

Fiscal deficit reached 23% of GDP in 2024 and no rebalancing is foreseen at least until 2033. Even before Russia's invasion, Ukraine had a fiscal deficit of 4% of GDP in 2021. As military spending increased by nearly ten times in 2024, the fiscal deficit increased to 16% in 2022 and 23% in 2024. The IMF expects this to go down over time, but even in 2033, the fiscal deficit could still be 1%. The total financing needs for the 2025-2033 period could amount to more than USD 72 billion, nearly 40% of the current GDP. With a tight budget, hydrogen projects might be a relatively low priority for the government, leaving grants and development finance as the most likely sources of public capital in the coming decade.

Foreign direct investment (FDI) flows plunged by more than 90% after Russia's full-scale invasion. FDI inward flows[16] reached a peak of nearly USD 11 billion (in current prices) in 2008, before halving in 2009 as a result of the financial crisis, and turning negative in 2015 as a result of the Russian annexation of Crimea in 2014. By 2021, they had recovered to USD 7.3 billion, only to drop to USD 530 million in 2022. Nearly 80% of these flows are from reinvestment of earnings, which is higher than the historical average of 55% in 2018-2019. Almost 23% of FDI flows are in the manufacturing sector and 7% are in the power sector. The total FDI stock in 2023 was nearly USD 55 billion, with Arcelor Mittal being the largest investor, with USD 6.5 billion. The government established an investment promotion office (UkraineInvest) in 2018 with a mandate to attract and support FDI, and the office has facilitated the investment of nearly USD 2.3 billion since 2020. Ukraine has 65 bilateral investment treaties in effect and free trade agreements with 48 countries. This could facilitate FDI once the war ends.

By December 2024, nearly USD 430 billion of bilateral support had been committed for Ukraine, with two-thirds already allocated. From the committed capital, 48% is targeted to military and humanitarian causes. The European Union (without counting the member states) and the United States account for more than USD 250 billion. Nearly 40% of the support from the United States is going to the government budget that could eventually be used for energy. Part of the European Union's support was through Macro Financial Assistance programmes, which covered aspects of energy security, energy efficiency, financial regulation of natural monopolies, and electricity market reform. The largest programme is the Ukraine Facility, with USD 50 billion over 2024 to 2027 to target EU accession, reconstruction, urgent financial needs (EUR 38.3 billion), de-risking and supporting the private sector (EUR 6.9 billion), technical assistance, capacity building and support to society (EUR 4.8 billion). By October 2024, the European Union, together with its member states and financial institutions, had provided a total of EUR 122 billion of financial aid to Ukraine, of which

[16] Inward flows are the value of cross-border direct investment transactions received by the country while outward flows are the overseas investments from the country. FDI flows comprise three components: equity capital, reinvestment of earnings which are not distributed as dividends and inter-company debt.

EUR 12.4 billion had been disbursed. In October 2024, the G7 launched the "Extraordinary Revenue Acceleration Loans for Ukraine", a USD 50 billion initiative. The loans have a maximum of 45 years and will be fully disbursed by 2027. In addition, more than USD 200 billion of multilateral financing has been pledged for Ukraine, but it is mostly for non-energy purposes. This includes USD 151 billion from the IMF and USD 55 billion from the World Bank Group.

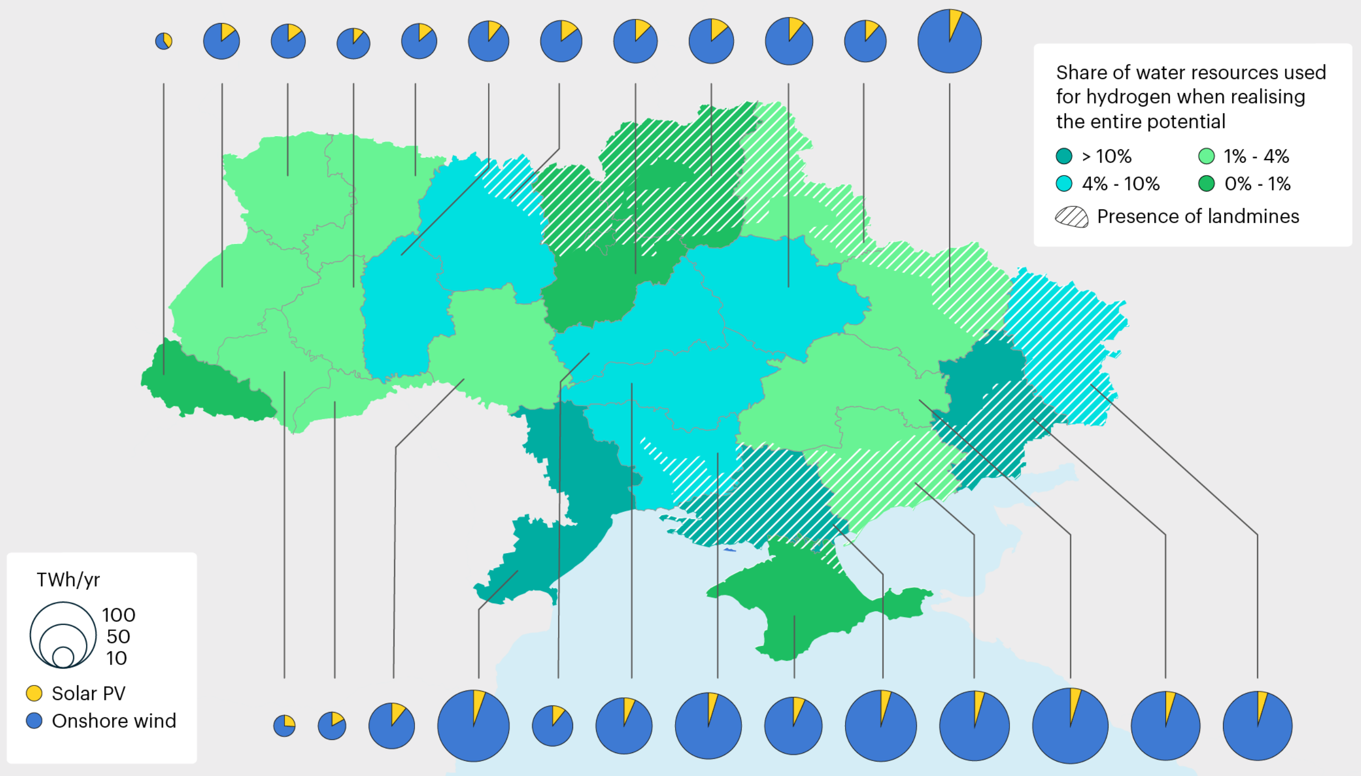
At the end of 2023, the weighted average cost of state debt was 6.2%, with an average maturity of 10.5 years. In 2023 alone, Ukraine received USD 42.5 billion in external financing. Nearly a quarter of this was in the form of grants, and the rest was in the form of concessional financing with lower interest rates or longer maturities. Over 50% of the funds were from international financial institutions and foreign governments, which together with external securities and loans from commercial banks, led to almost 70% of external (i.e. foreign) debt.

The hydrogen opportunity

Highlights

- Ukraine has 18-38 Mtpa of technical renewable hydrogen potential, though economic constraints would result in lower potential. Most potential is in regions with scarce water resources and competition from other industrial activities. Domestic demand for use for steel and fertilisers could reach 2.2 Mtpa, if pre-invasion capacity is restored, and the government target has set a target of 7.2 Mtpa of production by 2050. Most hydrogen production projects proposed prior to the invasion are close to the border with the European Union.
- Ukraine has a technical potential for solar PV and onshore wind equivalent to 9-14 times its pre-invasion electricity demand and 2-4 times its final energy demand. Half of this potential is in regions that are occupied or heavily mine-contaminated. The realisable economic potential is much lower, especially considering the current high cost of capital. Ukraine has a larger renewable resource capacity than Germany (a potential importer of hydrogen derivatives), but smaller than Morocco (an alternative supplier to Europe). The high cost of capital in Ukraine could offset lower costs from higher capacity factors.
- If repurposed, existing gas pipelines to the European Union could transport nearly 33 Mtpa of hydrogen (80% through Slovakia). Most of the capacity is now available. Ukraine also has 13 underground gas sites which could store 2.4 Mtpa of hydrogen; one site near the EU border has a capacity of 1.2 Mtpa. There are two initiatives exploring corridors to the European Union (1.5 Mtpa and 2.4 Mtpa) under development, but they currently lack off-taker involvement.
- Producing 2.5 Mtpa of hydrogen could generate annual revenues in the order of USD 18-22 billion from steel exports and exports by pipeline. It could also create up to 100 000 jobs, but 70% of these would be temporary positions related to construction, 50% are in equipment manufacturing, which could be located abroad, and 80% are related to constructing renewables rather than electrolysis. Focusing on electrification would therefore provide most potential job opportunities.
- Producing 2.5 Mtpa of hydrogen requires an investment of USD 85-90 billion for renewables and electrolysis. This is equivalent to 50% of the national gross domestic product in 2024 and 45-65% higher than the investment needed to reconstruct the entire energy system after the war. If this investment is funded with a cost of capital of 15%, interest payments could reach USD 165-175 billion (in nominal terms) over the entire lifetime of the assets.

Renewable technical potential



Hydrogen

18-38 Mtpa
hydrogen technical potential

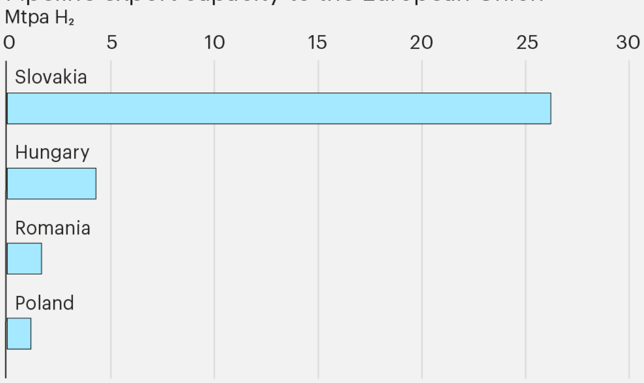
45%
potential in areas with landmines

66%
potential in areas with water stress

1/3
of the potential is in occupied territories

Gas

Pipeline export capacity to the European Union



33 Mtpa
export capacity to the EU

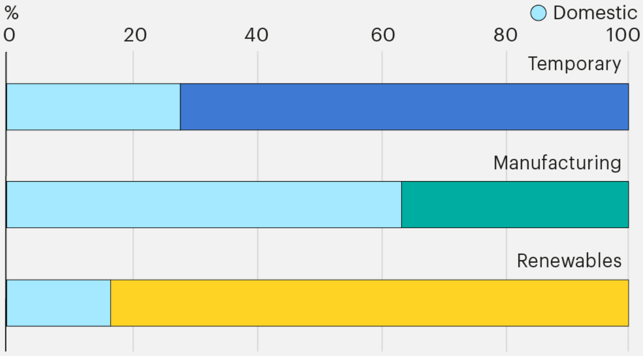
2.4 Mtpa
hydrogen storage capacity

Macroeconomy

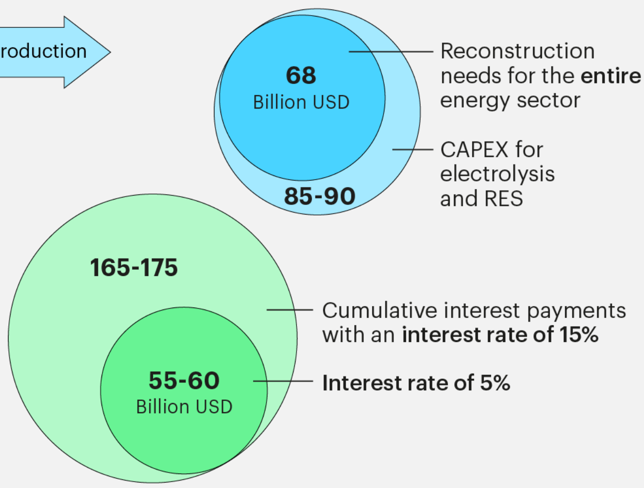
20 Billion USD
annual revenues for hydrogen/steel exports

2.5 Mtpa of H_2 production

100 000 jobs at peak, but...



Finance



This chapter is forward-looking, highlighting the potential barriers and opportunities for the development of renewable hydrogen. This includes the potential for production and export and how it compares with potential importers and competitors, and potential demand, including for steelmaking, as well as water constraints that could be faced. In the power sector, we assess the renewable potential and quality. Turning to infrastructure, we assess the capacity that existing pipelines and underground storage could have if repurposed for hydrogen, as well as some of the pipeline corridors to Europe that have been proposed. From the macroeconomic perspective, we discuss the potential revenues and jobs created by hydrogen production. Lastly, we assess the investment needs for a fully mature market.

Hydrogen

Supply

Ukraine's hydrogen production technical potential ranges from 18-38 Mtpa. The renewable potential has a high uncertainty depending on the criteria used for assessment.[1] A potential of 1 300-2 300 TWh/yr would be enough to produce about 26-46 Mtpa of hydrogen.[2] However, some of the potential will need to be used to satisfy domestic demand for electricity. Electricity demand prior to the invasion was about 150 TWh/yr. As the energy system decarbonises, the share of electricity will increase, especially as more efficient technologies are used. Assuming that national electricity demand grows at the same rate as global demand in a world moving towards a net zero emissions system, demand would reach about 405 TWh/yr. This would reduce the renewable potential available for hydrogen, but would still be enough to produce 17.8-37.5 Mtpa. This would be the upper limit and does not take into account the resource quality (i.e. capacity factors), which influence the hydrogen costs and the economic potential. Nor does it consider the geographical location and additional transport costs to reach the border.

A number of hydrogen projects had been proposed before Russia's full-scale invasion, but all were in the early stages and need reassessment. There were 13 proposed hydrogen projects, adding up to nearly 2 GW in their first phase (75% of this capacity came from the H2EU+Store project) and an ultimate capacity of more than 13.5 GW (see Table 2.1). Most of the projects were targeting hydrogen as a product, with three of them considering the possibility of also producing ammonia. Five projects targeted the local market in combination with exports, while the rest were export-oriented (or had not published relevant data). Most were targeting the use of pipelines to transport hydrogen, with some of the

[1] See the annex for a full list of studies estimating the potential.
[2] With a 67% efficiency on a lower heating value basis.

smaller projects considering road and rail transport. One of the largest projects was close to the Kakhovka dam that was destroyed in June 2023, and another, which is aiming for up to 10 GW of electrolysis, is near the war frontline and bordering occupied regions.

Table 2.1 Proposed hydrogen projects in Ukraine before Russia's full-scale invasion.

Name	Electrolyser capacity (MW)	Investment (EUR mn)	Product	Transport
Zakarpattia	Phase 1: 100 Vision: 1 500	Phase 1: 300	H_2	Pipeline, road
Reni	2028: 100 2030: 200	300-400	H_2, NH_3	Pipeline, ship
*Kakhovka / River Wind	Phase 1: 200 Vision: 1 100	Phase 1: 400 Phase 2: 2 000+	H_2, NH_3	Pipeline
Danube Hydrogen Valley	Phase 1: 50 Vision: 3 000	Phase 1: 100 Vision: 14 000	H_2, NH_3	River transport
H2 Production Sumy	110	280	H_2	Pipeline, rail
Transcarpathian green hydrogen	30-35	130	H_2	Pipeline, road, rail
Kyiv green data centre	20-30	125	H_2	Pipeline
European Galicia	Phase 1: 50 Vision: 200	400	H_2, NH_3	Rail, road
Lyiv Region	17.5	70	H_2	Pipeline
Green hydrogen industrial cluster	8.5 Vision: 10 000	25	H_2	Pipeline (H_2, NH_3), LOHC
Vinnytsia and Chernivtsi Regions	Phase 1: 10 Phase 2: 87	Phase 1: 14	H_2	-
H2EU+Store	Phase 1: 1 500 Vision: 80 TWh	105	H_2	Pipeline
Salt for Life	-	278-508	H_2	Pipeline

Notes: H_2 = hydrogen; NH_3 = ammonia; LOHC = Liquid Organic Hydrogen Carrier. Projects with an asterisk are in occupied regions, and/or in regions with severe damage due to attacks, and/or near the frontline.
Source: IEA analysis based on DENA (2021).

Two hydrogen valleys, in Zakarpattia and Reni, are the most advanced projects. The valley in Zakarpattia is less than 10 km from the border with Hungary (west). Initial electrolyser capacity is 100 MW, fed by 120 MW of solar PV and 80-160 MW of wind, which would be used to produce 105 ktpa. The full electrolyser capacity is expected to be 1.5 GW. The investment foreseen for the first phase is EUR 300 million with operation due to start in 2035. Targeted end uses include industrial feedstock, energy and road transport. The other hydrogen valley is in Reni, a city on the border with Romania (southwest). This project targets 100 MW of electrolysis by 2028, powered by 120 MW of solar PV and 80 MW of wind. A second phase would see an expansion to 200 MW by 2030, with potential for 3 GW later. In May 2024, the UK government funded a feasibility study through the InnovateUkraine programme, which will look at the construction of the renewable assets, the electrolyser and the pipeline, and assess the potential for underground storage in salt formations.

Hydrogen production from nuclear energy could, at best, reach production costs of USD 3.6-5.3/kg by 2040, subject to multiple conditions. Since nuclear represents more than half of the electricity generation in Ukraine, it could also provide a potential pathway for hydrogen production. In addition, at COP 28, Ukraine endorsed a declaration to triple nuclear energy capacity by 2050. However, Ukraine has not built any nuclear reactors since 2004, which means there is a lack of domestic know-how regarding plant construction and there are no recent cost estimates. In 2021, an agreement between Westinghouse (a nuclear technology provider) and Energoatom (the state-owned enterprise operating the nuclear plants) put the total cost of the construction of four new reactors with a total capacity of 4.6 GW at USD 30 billion. This results in a CAPEX intensity of nearly USD 6 500/kW. This roughly corresponds to the current capital costs of nuclear plants in the European Union. Costs could come down with experience, technology innovation and policy support. Assuming the costs in Ukraine follow a similar trajectory to in the European Union, costs could reach USD 4 500/kW by 2040. With the addition of fuel and operating costs, the levelised cost of electricity would be USD 75-110/MWh, which is equivalent to USD 3.6-5.3 per kilogramme of hydrogen (H_2). Achieving this cost would require at least three conditions to be fulfilled. First, that plants are constructed on budget and on time, which has not been the case for recent nuclear plants constructed outside China, which have seen costs of USD 6 000-16 000/kW and construction times of 8-16 years. Second, a cost of capital of 4-8%, which is one- to two-thirds lower than the pre-war WACC. Third, that the 30% capital cost reduction materialises.

Demand

Potential domestic hydrogen demand from industrial applications could reach 2.2 Mtpa. Before Russia's invasion, hydrogen demand was nearly 1 Mtpa (see Chapter 1. "Taking stock of the effect of war"). This was used mainly for ammonia production and, to a smaller extent, for oil refining. Steel production was 22 Mtpa. If all such production were restored using direct reduction of iron, the corresponding hydrogen demand would be 1.3 Mtpa.[3] This corresponds to about 10% of the renewable hydrogen potential. There is also a geographical correlation between the sites where industrial activity was highest before the invasion and the regions with the highest renewable potential and capacity factors.

Direct reduction of iron with hydrogen could leverage Ukraine's iron ore reserves. Ukraine holds about 3.5% of global iron ore reserves, which have a lower iron content[4] (about 35%) than the global average (45%).[5] In contrast, direct

[3] Assuming a hydrogen demand of 55 kg H_2 per ton of DRI and an additional 5% for the conversion from direct reduced iron to steel.
[4] The iron ore quality also depends on the company. Some companies (e.g. SevGOK) may supply the iron ore that meets the requirements of the DRI process.
[5] This refers to the global average for iron content of the reserves, while production has a higher content of 62%.

reduction of iron with hydrogen (H_2-DRI) requires high-grade iron ore, since the process does involve melting or refining, which is the way impurities are usually removed. High-grade iron ore of 67% is therefore needed. At the same time, iron ore must be in the pellet form for use in H_2-DRI. Only about 4% of the global iron ore exports in 2020 were in pellets with a high iron content. The iron content is important because it can affect the efficiency and operation of the electric arc furnace, the degree of metallisation and the mechanical properties of the iron oxide produced, among other factors. Some of the solutions include the use of fluidised bed technology (which could avoid the need to use pellets), an additional smelting unit to remove impurities via slag production, and increasing the iron content of the ore through a process called beneficiation. Either way, the lower iron content of Ukrainian iron ore could require two additional steps (pelletising and beneficiation), which translate into additional cost. The beneficiation premium can be about USD 7-8/t for every percentage point of increase in iron content, resulting in about USD 40/t for going from the global average of 62% to the 67% required. This is significant, considering that the average price of iron ore was USD 90-140/t in 2023-2024. Several companies have plans to invest in pellets and concentrate plants.

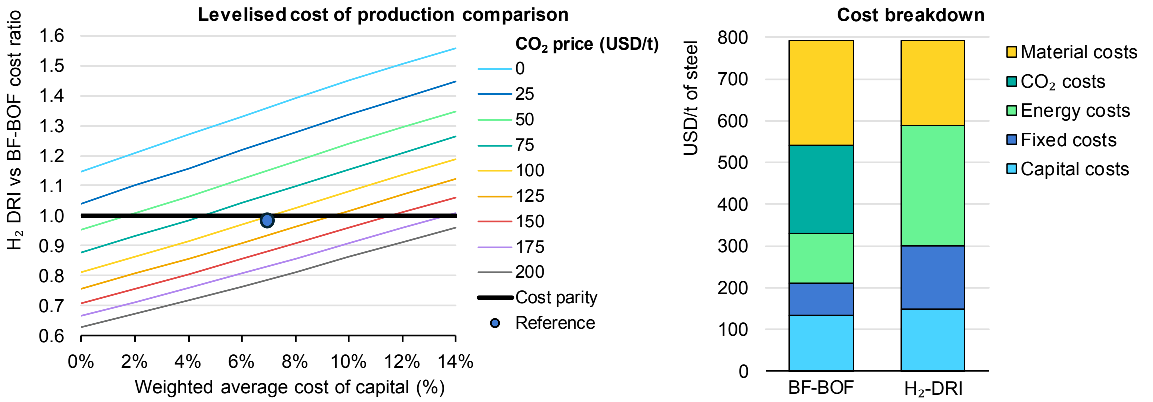
Proximity to the large demand from the European Union could drive hydrogen development. Hydrogen demand in the European Union was nearly 8 Mtpa in 2023. This is expected to increase to 15-73 Mtpa[6] by 2050, with the large range reflecting differences in the level of ambition, technology portfolios and assumptions relating to reliance on specific levers. At the same time, even with the European Union's large renewable potential, imports will most likely be needed. Ukraine has the advantage of being able to export by pipeline, which has a lower transport cost than shipping for distances shorter than 5 000 km. Legislation already in place represents a demand of about 2 Mtpa for low-emissions hydrogen .[7] At the same time, the European Union had a real steel demand of 135-150 Mtpa in the 2014-2023 period, with imports of 20-30 Mtpa. While the bloc also exported 16-29 Mtpa over the same period, the net import was 9-12 Mtpa in 2022-2023. For reference, 5 Mtpa of steel demand would require about 0.3 Mtpa of hydrogen, which would in turn require 3 GW of electrolysis.[8]

The EU Carbon Border Adjustment Mechanism (CBAM) could trigger additional hydrogen demand. The CBAM is being phased in from 2026 to 2034 and it currently covers six products including hydrogen, fertilisers, and iron and steel. This means that any imports of these products to the European Union will be subject to the carbon price, thereby providing an incentive for decarbonisation of the imports. For Ukraine, this represents a mechanism to close the cost gap for the renewable hydrogen routes. For steel, in 2021, about a third of Ukraine's steel

[6] 10th and 90th percentile based on 32 scenarios.
[7] Renewable Energy Directive, FuelEU Maritime, ReFuelEU Aviation.
[8] Assuming 5 000 full load hours per year.

exports were to the European Union. For a fixed capital cost and energy price, the cost differential between the renewable route (H_2-DRI) and the conventional route (blast furnace) is a function of the CO_2 price and the cost of capital (see Figure 2.1). The lower the cost of capital by using de-risking instruments (see Chapter 3. "Unlocking the opportunity – A roadmap for action"), the lower the CO_2 price needed to close the cost gap. In the past 3 years, the EU Emissions Trading System (ETS) price has been at EUR 60-100/t CO_2, which means the cost of capital would need to be 2-7%. Looking further ahead, the CAPEX for the renewable route will decrease through deployment and learning for both the electrolyser and the DRI plant, and the CO_2 price is expected to increase as the emissions reduction accelerates. Once Ukraine's EU accession process has been completed, the domestic ETS price should follow the same cost trend, so the gap would not be closed by the CBAM, but by the domestic ETS.

Figure 2.1 Cost comparison between the hydrogen-direct reduced iron route and conventional steel production in Ukraine as a function of CO_2 price and cost of capital, 2023



Notes: BF = Blast Furnace; BOF = Basic Oxygen Furnace; H_2-DRI = hydrogen-based direct reduced iron. Right graph takes the reference point from the left graph to provide the cost breakdown. Grid electricity price for blast furnace = USD 63/MWh. Electricity price for H_2-DRI based on same assumptions as Figure 1.4. CO_2 intensity of 2.1 t CO_2/t of steel for the BF-BOF route.

The CO_2 price could close the cost gap between H_2-DRI and the conventional route, but the cost level required is dependent on the cost of capital.

Ukraine could produce the equivalent of 20-80% of its oil demand in the form of synthetic oil, if the domestic biogenic CO_2 potential is used. Ukraine has a biomethane potential of 6-22 bcm. [9] Biomethane is produced by separating the CO_2 from biogas to leave a high purity (> 95%) stream of methane. The original biogas typically has a CO_2 content of 45-75% depending on the feedstock and process, but that biomethane potential could be associated with 7-25 Mtpa of CO_2

[9] From agricultural residues, cultivated crops, woody biomass, manure, organic waste and sewage.

production. If used for synthetic oil production by combining it with renewable hydrogen (through the Fischer Tropsch process), that would be enough to produce 80-292 PJ/yr, which is approximately equal to 20-80% of the 352 PJ/yr of the oil demand in Ukraine in 2021. This could also be used for methanol production, providing an opportunity to establish a new industry, given that there was no domestic methanol production before the invasion.

Water

Water availability for hydrogen production could be most critical in Donetsk, Kherson and Odesa. Both water resources and withdrawal prior to the invasion have large regional differences. Most of the water resources are in the north,[10] while most water withdrawal is in the south. Therefore, the ratio between withdrawals and average resources is the worst (40-80%) in the south and southeast regions, where most of the industrial activity was located before Russia's invasion (and where the best renewable resources are). This reaches more than 80% in the industrial region of Donetsk, where the city of Mariupol is located (which has been completely destroyed by the war). Hydrogen production alone could account for more than 10% of all the water resources in the Donetsk, Kherson and Odesa oblasts (see Figure 2.2). This is without considering competing uses for the water, which are most critical in southern regions – the latter three oblasts are where the most water is withdrawn today (nearly 3 800 million m^3).

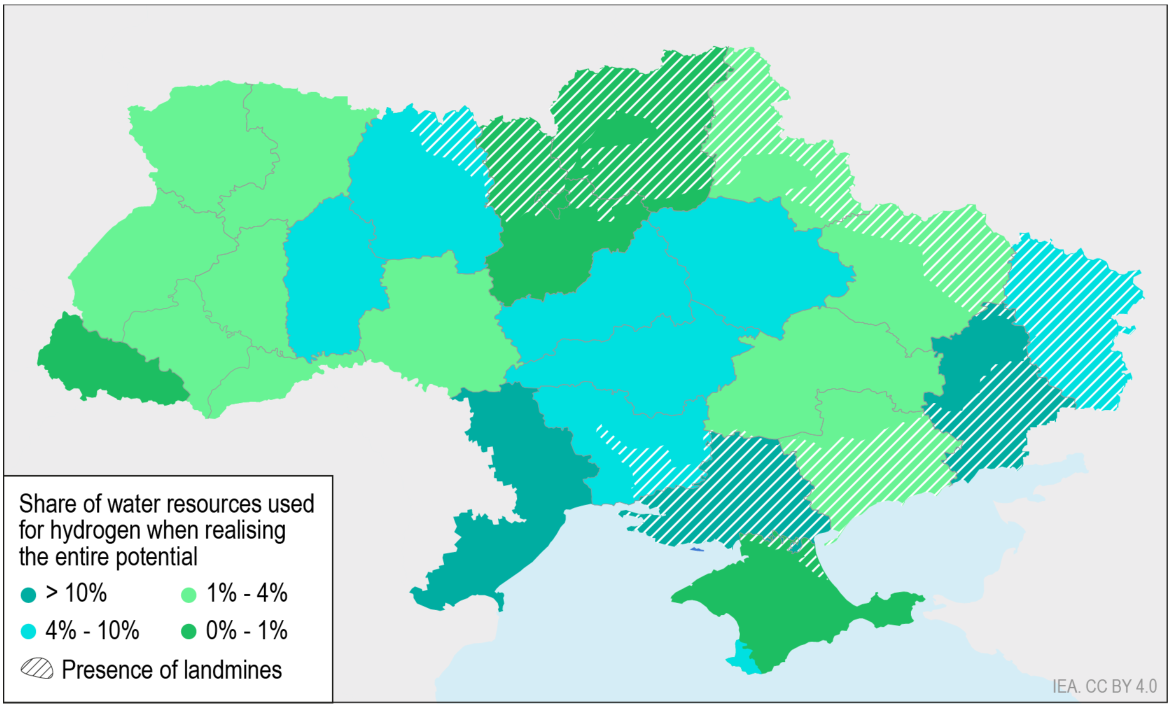
Climate change could exacerbate water stress in Ukraine. The potential risks associated with climate change include heat waves, flooding and (extended) droughts. The number of hot days, duration of the heat waves and the heat load have already increased in Ukraine. As much as 30% of the national territory is exposed to flooding risk, and the area of (very) dry zones has increased by 7% since 1991, and now covers almost a third of the national territory. In the future, river discharge is expected to decrease in most of the river basins by 2070-2100, even in a scenario in which global temperature increases are limited to 1.5-2°C, with the peak of spring run-off shifting to earlier months, and lower run-off in summer. Similarly, precipitation could increase up to 10% on average in a 1.5-2°C scenario, with more precipitation in winter. Southern regions (where most of the renewable potential is) could experience 12-14% lower precipitation in a scenario with a temperature increase of more than 2°C. Heat waves, heavy precipitation, flooding and drought are all expected to increase.

Realising Ukraine's full hydrogen potential could consume more water than was consumed by all industry sectors prior to the invasion. Producing 19.5 Mtpa of renewable hydrogen would require using nearly 1 150 million m^3 of

[10] 50% of the water resources are in the Danube basin (bordering the European Union), which means other parts of the country have an even smaller share of resources.

water.[11] Total water resources in Ukraine are nearly [175 000 million m³], out of which 97% is formed by surface river run-off and nearly 30% originates from within the country's borders. Water supply is an issue for Ukraine, with the average resident having access to 1 280 m^3 of annual local run-off, which is below the threshold established by United Nations Development Programme to define water stress (1 700 m^3 per capita). The 1 150 million m^3 used for hydrogen would be more significant when compared to water withdrawal (instead of resources), which was 9 220 million m^3 in 2021, of which 27% was for the energy sector and 11% for industry.

Figure 2.2 Share of water resources withdrawn for renewable hydrogen production from realising Ukraine's entire hydrogen potential



Source: IEA analysis based on Snizho et al (2024), National Academy of Sciences of Ukraine (2020).

If all of Ukraine's hydrogen potential were realised, water used for hydrogen production would account for more than 10% of resources in Donetsk, Kherson and Odesa.

Power

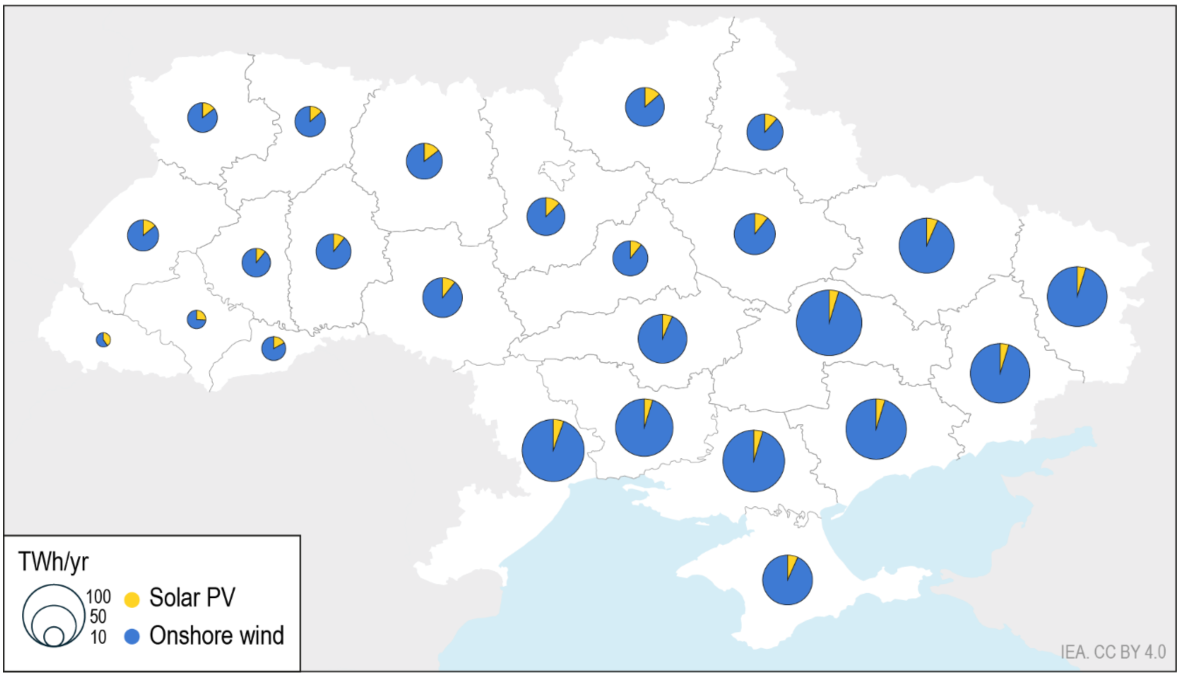
Renewable potential

Ukraine has 1 300-2 300 TWh/yr[12] of wind and solar technical potential, with most of it coming from wind (see Figure 2.3). As a reference, power generation

[11] This corresponds to water withdrawal assuming a conservative estimate of 60 L/kg (10 L/kg for the process side and 50 L/kg for cooling). The water used for cooling is not consumed in the process and can be used afterwards for other purposes. Other studies have estimates of 26-32 L/kg in total.
[12] Upper bound includes offshore wind.

before the full invasion was nearly 150 TWh/yr and the primary energy supply was nearly 1 000 TWh/yr. About one-third of the potential is in occupied territory. Additionally, Ukraine also has another nearly 1 000 TWh/yr of offshore wind potential in territorial and inland waters. The range of potential estimates is wide depending on the criteria used and the type of potential (technical vs. economic), and also on the land exclusion zones and criteria. The annex contains a collection of studies estimating the potential for solar PV and onshore wind, while we use our own estimate for the supply cost curve for renewable hydrogen.

Figure 2.3 Onshore wind and solar PV potential by oblast



Source: IEA analysis based on National Academy of Sciences of Ukraine (2020).

Ukraine has nearly 1 300 TWh/yr of wind and solar technical potential, of which more than 90% comes from onshore wind.

Land use for agriculture might be subject to additional constraints. Two-thirds of the land area in Ukraine is used for agricultural purposes. To be able to use privately owned land for renewables, any opportunity costs related to alternative land uses would need to be overcome. In parts that are state-owned, approval by different levels of the government would be needed. In addition, nearly 56% of Ukraine's land area is covered by black soil,[13] most of which has a special status as "particularly valuable land". This means it has special legal protection and there are restrictions on changing its purpose (including for renewable

[13] These are soils rich in organic carbon and with high fertility used for intensive agriculture and susceptible to degradation. Ukraine holds about 5% of the global black soil area.

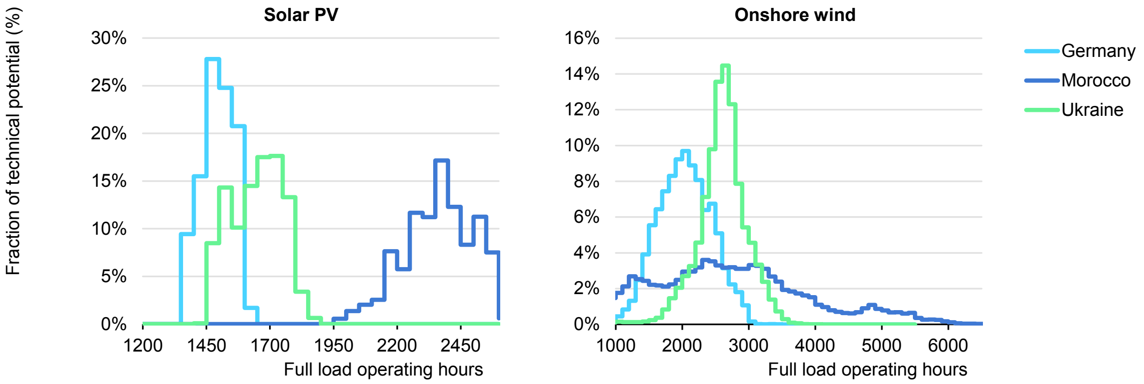
generation), including a need for additional compensation. Despite this, a law passed in 2024 aims to simplify land conversion from agricultural uses to facilitate the country's reconstruction.

Nearly half of the renewable technical potential is in oblasts that are either currently occupied or heavily contaminated with land mines. An additional step of surveying and demining would therefore be required before any renewable projects are constructed – adding time to the process. There is not only an immediate security risk in these areas, but the overall risk profile is higher, given that these areas have experienced the most damage due to attacks. In many cases, pre-existing infrastructure has been completely destroyed and additional efforts and investments would be needed to remove the debris. The oblasts close to the border with the European Union have the smallest potential of all, and additional transport would be needed if the resources in the southeast are exploited. For example, the distance from the area around Mykolaiv, where a lot of the renewable plants are today, to the Polish border, is about 800 km. This is therefore almost double the distance from the industrial centres of West Germany. The cost premium for covering this distance could be small if existing infrastructure can be repurposed, but it would still increase the transport cost.

The average quality of renewable resources in Ukraine is better than Germany but worse than in the European Union's other neighbouring regions. A large part of the business case for hydrogen in Ukraine is based on exports. Most of these exports are expected to go to the European market, given its proximity and the possibility to use existing pipelines. Germany is the largest hydrogen consumer in Europe, so comparing it with Ukraine allows for an assessment of competitiveness. For solar PV, Ukraine has average full load hours about 11% higher than Germany (see Figure 2.4). In terms of amount of energy, Ukraine has nearly ten times Germany's potential.[14] Morocco, which is an alternative exporter of hydrogen to Europe, has more abundant solar resources with higher quality. The average full load hours in Morocco are 45% higher than in Ukraine and the total potential is more than three times higher. For onshore wind, the story is similar: Ukraine has average full load hours 17% higher than Germany, but Morocco has nearly 18% more full load hours than Ukraine. In terms of potential, Morocco and Ukraine have nearly 7- and 10-times Germany's potential, respectively, with the big difference that more than 60% of Morocco's potential has more than 2 630 full load hours (30% capacity factor) while only about 36% of Ukraine's potential is in this range.

[14] This potential value and the average capacity factor comparison exclude resources with a capacity lower than 12.5% for solar PV and 20% for onshore wind since those resources might be economically unattractive.

Figure 2.4 Capacity factor distribution for renewables in Germany, Morocco and Ukraine



Notes: Solar PV with single-axis tracking. Weather data from 2018.
Sources: IEA analysis based on data from Jülich Systems Analysis at Forschungszentrum Jülich using the ETHOS model suite.

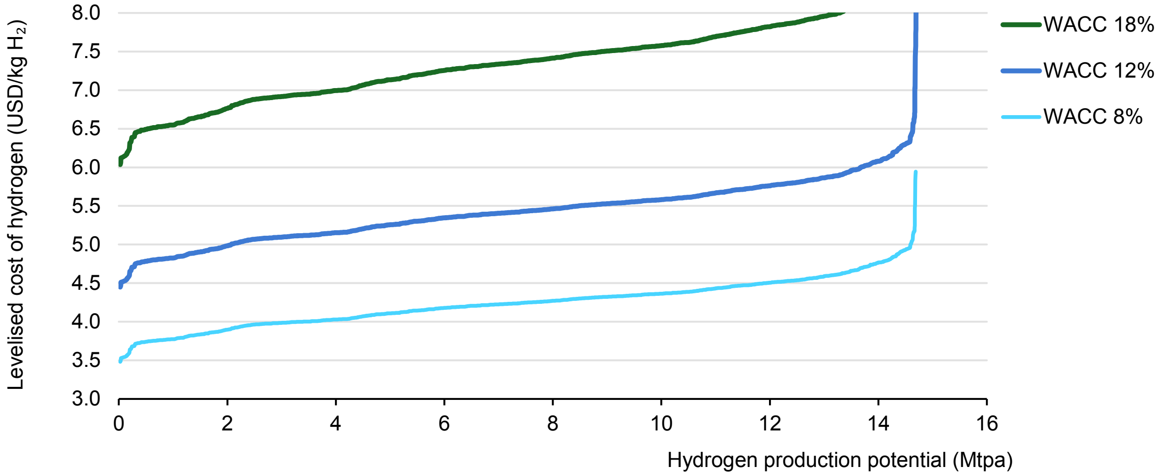
The average quality of renewable resources in Ukraine is better than in Germany, but much worse than in other regions that neighbour the European Union.

Cost

There is a cost difference of 30-50% between Ukraine's least expensive and most expensive hydrogen. The cost of hydrogen production is defined by the cost of capital, the capital cost of the assets and the utilisation of those assets. The first two parameters will change over time, while the last one is constant (for renewables). Even in 2035, by which time capital costs are expected to have come down, the least expensive hydrogen Ukraine can produce costs slightly more than USD 3.5/kg. This is assuming a cost of capital of 8%, which would be lower than the pre-war level for renewables. It also assumes that renewable resources with the lowest cost would not be available for hydrogen, and would instead be devoted to direct electricity use (which is more efficient). As the best and cheapest resources are already being used, cost increases by USD 0.1-0.16/kg for every additional Mtpa of hydrogen produced, resulting in a cost premium of 30-50% for the most expensive resources (see Figure 2.5). A different technology learning curve and cost trajectory could shift this profile, but the cost of capital can have a bigger influence than CAPEX. For reference, the technical hydrogen potential for Ukraine of 18-38 Mtpa[15] is much larger than pre-war domestic demand and almost double the European Union's hydrogen demand in 2023. It would still be equal to or lower than the projected 2050 demand, for which most scenarios fall within 15-73 Mtpa.

[15] This is based on the renewable potential from literature, while the 14.7 Mtpa from Figure 2.5 is from this report. See the annex for details.

Figure 2.5 Supply cost curves for renewable hydrogen based on hybrid onshore wind-solar PV configurations, 2035

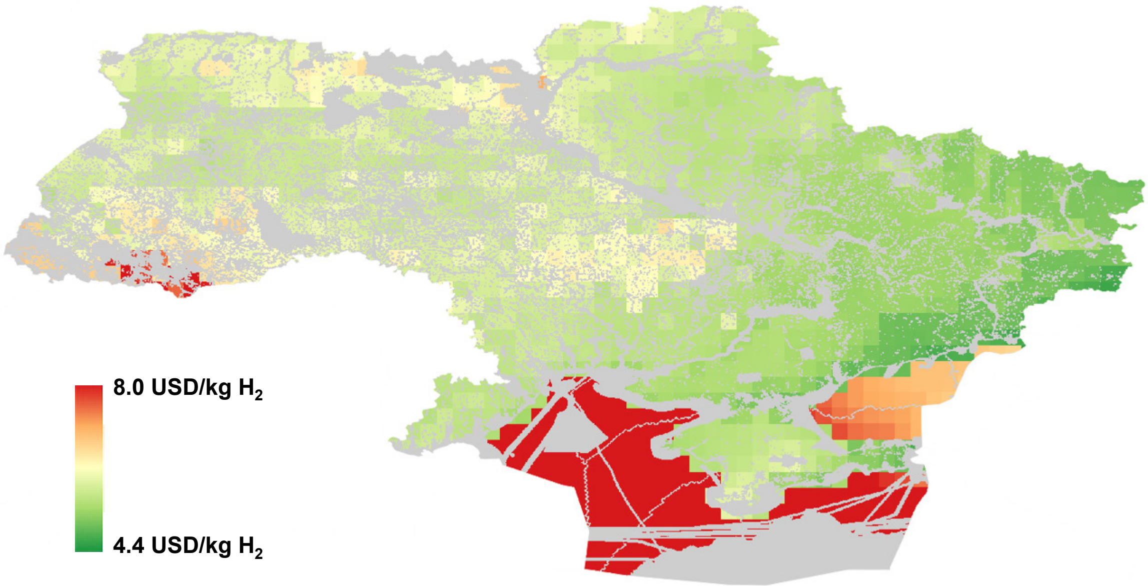


Notes: WACC = weighted average cost of capital. CAPEX of USD 1183/kW for electrolysis, USD 1315/kW for onshore wind, USD 639/kW for solar PV and USD 175/kW for batteries. Asset capacities are optimised based on total levelised cost for each area of 0.25x0.25°. Potential in the figure is based on 10% of land available after considering land exclusion zones, while the 18-38 Mtpa mentioned in the text refers to literature. See annex for details.
Sources: IEA analysis based on data from Jülich Systems Analysis at Forschungszentrum Jülich using the ETHOS model suite.

Even with a low cost of capital of 8%, the hydrogen potential for Ukraine with a production cost below USD 4/kg is less than 3.5 Mtpa.

The lowest hydrogen costs are achieved in areas that are today occupied, mine-contaminated or extensively damaged. The southeast of Ukraine combines the best solar and wind resources, which allows for the lowest hydrogen production costs (see Figure 2.6). These areas also had high industrial activity before Russia's full-scale invasion, which could provide opportunities for hydrogen use in the chemicals or steel sectors. However, these areas are also at the war front at present and have experienced the most extensive damage (see Chapter 1. "Taking stock of the effect of war"). The alternative of using resources that are not in occupied areas today could result in a cost premium of at least 25%.

Figure 2.6 Levelised cost of hydrogen for Ukraine based on hybrid onshore wind-solar PV configurations, 2035



Notes: Cost of capital =12%. CAPEX of USD 1183/kW for electrolysis, USD 1315/kW for onshore wind, USD 639/kW for solar PV and USD 175/kW for batteries. Asset capacities are optimised based on total levelised cost for each area of 0.25x0.25°. Land exclusion zones that are not available for renewable hydrogen production are listed in annex.
Sources: Analysis by Jülich Systems Analysis at Forschungszentrum Jülich using the ETHOS model suite.

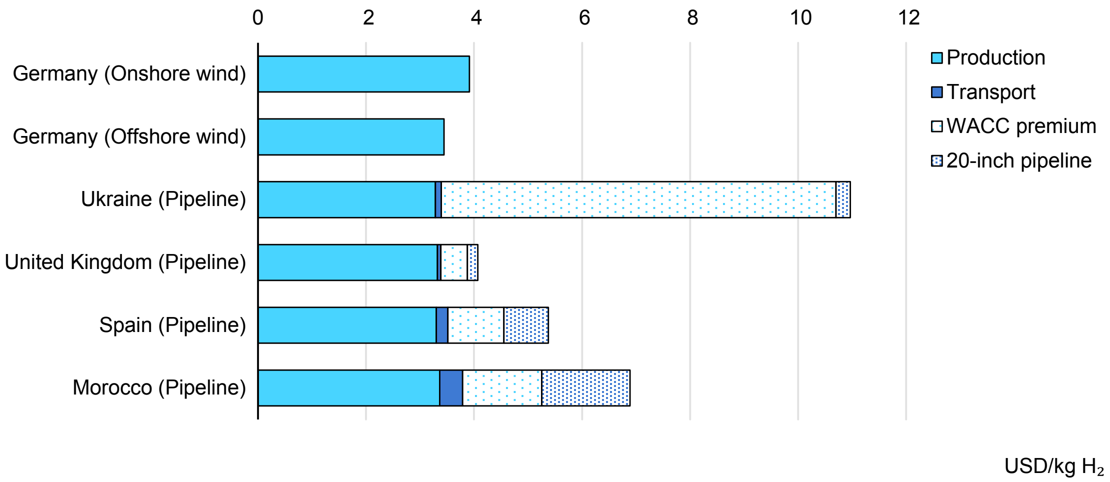
The lowest production cost achieved in 2035 is above USD 4/kg in regions that are currently occupied, mine-contaminated and suffering extensive destruction from the war.

Hydrogen imports from Ukraine to Germany could be cheaper than alternatives but the WACC remains a major challenge. The average resource quality of onshore wind is higher in Ukraine than in Germany and it also has lower capital cost. In 2023, the capital cost of onshore wind in Ukraine was USD 1375/kW, while in Germany it was about USD 1750/kW. This means that if Ukraine were to reach the same WACC as Germany,[16] the production costs could be nearly 20% lower (see Figure 2.7). When adding transport, the cost differential falls to 14%, taking advantage of a large share of the transport being through repurposed natural gas pipelines (see next section). However, a WACC premium of 3-3.5% would close this cost gap. This is much lower than the differential of more than 10% prior to the invasion, and much lower than the current WACC difference (see Chapter 1. "Taking stock of the effect of war"). Even when using de-risking mechanisms to mitigate most of the war risks (e.g. political risk insurance – see Chapter 3. "Unlocking the opportunity - A roadmap for action"), it might be difficult for Ukraine to reach the low WACC levels seen in Germany. The breakeven WACC premium would be lower if, for example, a smaller pipeline was

[16] The WACC for solar PV and onshore wind in Germany was 1.3% (real after-tax terms). This is corrected by expectations of changes in risk-free rate which are assumed to follow the 10-year US treasury bonds. This results in a WACC premium of 2.2%.

used, or if the share of repurposed pipelines were lower. The production costs of other potential exporters by pipeline are comparable to those of Ukraine and other factors like diversification, geopolitics and certainty of supply might play a larger role in defining the import mix.

Figure 2.7 Hydrogen production and transport costs to Germany in 2035



Notes: WACC = weighted average cost of capital. Cost decrease to 2035 as per the Stated Policies Scenario. Production in Ukraine based on onshore wind, United Kingdom based on offshore wind and Spain and Morocco based on solar PV and batteries. Solid bars represent the levelised cost if locations had a cost of capital of 4.2%, while the bars with dotted patterns are the cost premium when the country WACC assuming the differentials between countries remain the same as in 2021. A 48-inch pipeline is assumed to be the transport cost, with an additional pattern-filled bar to represent the cost premium for using a 20-inch pipeline. It is assumed that 80% of the pipeline from Ukraine is repurposed, 50% of the one from the United Kingdom and 20% for Morocco and Spain.
Sources: IEA (2023), Energy Technology Perspectives 2023, and IEA analysis based on IRENA (2024); IRENA (2023).

Total import cost from Ukraine could be the lowest among neighbouring countries, but the cost of capital introduces a large cost premium.

Gas

Existing gas interconnection pipelines to the European Union have a technical capacity equivalent to nearly 33 Mtpa.[17] Nearly 80% of the cross-border capacity[18] is to Slovakia (26.3 Mtpa), which has multiple pipelines including one of 1 400 mm and one of 700 mm. Hungary is second with nearly 4.3 Mtpa of capacity and a virtual interconnection point (VIP), which means there are multiple parallel pipelines available that are managed as a single trading point. Romania has multiple pipelines (one of 1 000 mm and one 700 mm), which together would have a capacity of 1.7 Mtpa. Interconnection with Poland is via a VIP with a capacity of 1.1 Mtpa. To provide a reference for some of these numbers, 1 Mtpa

[17] The transport capacity of a natural gas pipeline declines to about 80% when transporting hydrogen. Hydrogen has roughly a third of the volumetric heating value of natural gas, but it also has a volumetric energy density that is eight times lower (due to the lower molecular weight), so a larger volumetric flow (of about three times) can be transported for hydrogen while achieving a similar pressure drop (and therefore, pipeline capacity).
[18] Ukraine is also interconnected with Moldova, but Moldova is not part of the European Union.

of hydrogen demand would be equivalent to about five large-scale ammonia plants and nine steel plants.[19] The total primary steel (hot metal) production in Slovakia, the Czech Republic, Austria and Germany, which could be either transit or target countries for pipeline corridors, would be equivalent to about 2.3 Mtpa of hydrogen demand. The current hydrogen demand for ammonia production in these countries is about 0.5 Mtpa. If all the existing pipelines could be repurposed for hydrogen, cross-border capacity would not be an issue since there are multiple parallel pipelines and capacity is higher than the renewable potential. The capacity may not all be available, since it could also be used for biomethane exports. In 2024, biomethane exports were estimated to be 0.1 bcm (in comparison to a network capacity of 146 bcm). The potential production by 2030 could be 1 bcm, and the total potential is 6-22 bcm.

Ukraine could store about 2.4 Mtpa of hydrogen in existing underground sites, but these require technology de-risking. Ukraine has 13 underground storage sites with a working capacity of 32 bcm. Hydrogen has a lower molecular weight and density than methane, which means the storage capacity is reduced by nearly 75% when storing hydrogen. This means that the storage capacity is 2.4 Mtpa of hydrogen. Two of the sites are aquifers and the rest are depleted gas fields. Gas fields present several challenges for hydrogen storage. They are permeable (which can result in hydrogen losses to the reservoir), can contain contaminants or by-products from reactions with the reservoir (which need removal), and are the least flexible of underground storage options. On the other hand, they typically have a large capacity and are more suitable for hydrogen storage than deep saline aquifers. More than 50% of the storage capacity is in a single site close to the border with the European Union in the West. This is far from the sites with the largest renewable potential, but might be better from the perspective of security of supply, since export from the storage would not depend on domestic pipelines.

A proposed 1.5 Mtpa corridor to the European Union, using existing pipelines, is under evaluation, but off-takers are needed. The Central European Hydrogen Corridor (CEHC) would have a length of 1 350 km, crossing Slovakia, the Czech Republic and Germany. The initial maximum capacity is expected to be nearly 1.5 Mtpa[20] with final investment decision (FID) in 2028 and commercial operation after 2030. The estimated investment is EUR 1-1.5 billion, which is possible given that more than 90% (by length) will use repurposed pipelines. Pipeline diameters vary from 900 mm to 1 400 mm, with the smallest pipelines in Slovakia. Transmission System Operators (TSO) have been closely involved, but there are no off-takers for the demand. The project was included in the sixth list of Projects of Common Interest (PCI) of the European Union

[19] Assuming sizes of 3 000 t/d of ammonia and 2 Mt of steel production.
[20] This is assuming full utilisation, which might not be the case during early stages of the market.

published in November 2023. This classification provides the benefit of accelerated planning and permitting, streamlined environmental assessment processes and increased visibility for investors. In January 2025, the Ukrainian gas TSO signed a Memorandum of Understanding (MoU) with other TSOs and companies involved in the corridor, agreeing to support its development and committing to complete a feasibility study for retrofitting the pipelines within 12-18 months.

There is another corridor to the European Union through Austria, with a potential capacity of 2.4 Mtpa by 2050, but it also lacks off-takers. The "H2EU +Store" project was launched by an energy storage company in Austria (RAG Austria) and a renewable developer in Ukraine (Eco-Optima). The route would cross Slovakia, Austria and Germany, largely relying on repurposed gas pipelines. The project is divided in three phases targeting a capacity of 75 ktpa by 2030, 1.2 Mtpa by 2040, and 2.4 Mtpa by 2050. Project participants are mostly TSOs and companies working on gas supply, but there are no potential off-takers. A feasibility study was due to be finalised by the end of 2024.

Macroeconomic factors

The annual revenue potential from producing 2.5 Mtpa of hydrogen, with 50% used for steelmaking, could be in the order of USD 18-22 billion. A production capacity of 2.5 Mtpa reflects the capacity of the pipeline corridors being explored, represents using about 12.5% of the national renewable potential, and is in the range considered by the government in the draft hydrogen strategy for 2035-2050.[21] The revenue from hydrogen export would be dependent on what buyers are willing to pay, where the alternative is either local production or import from another country. Assuming the hydrogen price is around USD 3-4/kg[22], exporting half of the potential production as hydrogen through pipelines could generate annual revenues of about USD 3-5 billion. Steel export would require additional investment, but it would also lead to higher value added, and potential revenues in the order of USD 15-18 billion. For reference, steel exports from Ukraine fluctuated in the range of USD 7-15 billion in the decade before the war.

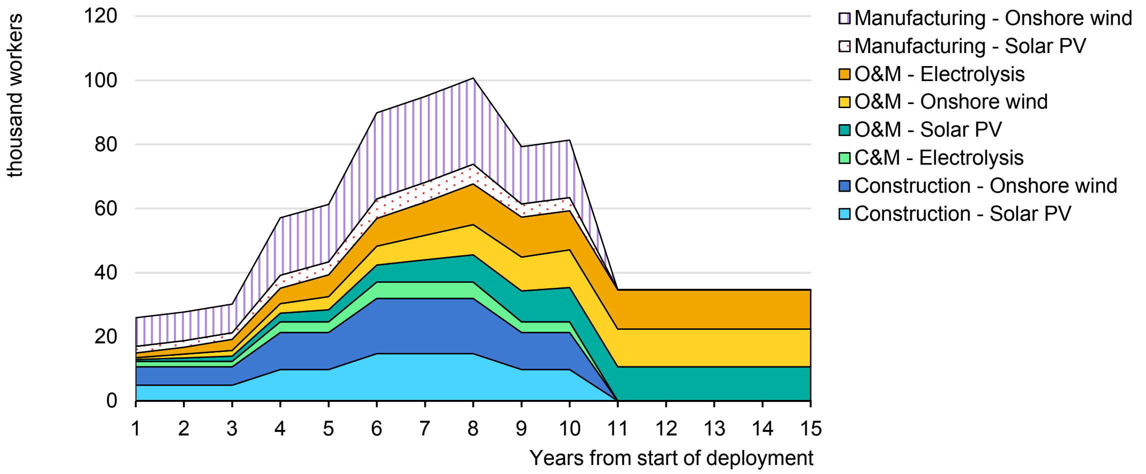
Deployment of renewables and electrolysis capacity for 2.5 Mtpa for can create up to 100 000 jobs. A gradual deployment of the capacity over 10 years (which is optimistic from the perspective of job creation) would require up to 100 000 people towards the end of this period (see Figure 2.8). As a comparison, in 2021, prior to Russia's invasion, the entire renewable sector employed about

[21] The draft strategy had 1.3 Mtpa in 2035 and 3 Mtpa in 2050, while plans presented during the Ukraine Recovery Conference 2023 were more ambitious, with production of 1.5 Mtpa by 2032 and 7.2 Mtpa by 2050 (with nearly half for export).

[22] There are several mixed factors. Technology learning will lead to lower costs over time, cost of capital might change over time with central banks' interest rates, early production will most likely be through long-term contracts locking in some of the higher costs, so this value is used just to have an indication of the order of magnitude.

40 000 people, of which nearly 45% were employed in the solar PV industry. This was about 10% of the labour force for the entire energy sector, which was estimated to be 400 000 people in 2018. By 2023, the labour force for renewables had halved to 19 000 people, with only 30% working in wind and solar PV. In 2021, nearly 565 000 people were employed in the steel sector, of which 15% joined the army once the war started. Labour availability may be an issue, not only during the ramp-up phase of construction, but also once experience with large-scale facilities has been developed. Even in a mature market like the United States, where there are about 360 000 workers in the solar industry, 94% of construction employers report some difficulty in finding qualified workers. In Germany, there are skills gaps in 190 relevant professions and vacancy periods of six months were reported for wind technicians.

Figure 2.8 Direct and indirect job creation from deploying 2.5 Mtpa of hydrogen over 10 years



Notes: C&M = construction and manufacturing; O&M = operating and maintenance expenses. Assuming a 75/25 split in solar PV/onshore wind and global productivity in 2023 instead of Ukraine-specific values. Productivity fixed over time. Jobs associated with manufacturing for onshore wind and solar PV have a hatched pattern because those will most likely be located abroad.

Source: IEA analysis based on Hanna et al. (2024), CE Delft (2021), LBST (2021), NRCan (2020), Navigant (2020), Vivid Economics (2019), HyNet (2018), UNECE (2021).

Deployment of hydrogen capacity over 10 years could create up to 100 000 direct and indirect jobs in renewables and electrolysis, though many would be temporary positions.

Over 70% of the jobs are temporary and associated with construction and manufacturing. For solar PV and onshore wind, the number of jobs in operation and maintenance are at least an order of magnitude smaller than the jobs associated with the manufacturing and construction of the assets.[23] This means

[23] These are the four categories covered in this analysis. There are other categories like trade, professional and business services and industry associations, among others, which are excluded. These vary depending on the technology and market. For example, in the United States, for solar PV, almost a third of the workforce worked in these areas.

that most of the jobs will be temporary, i.e. only for the construction phase, with a fraction of the workforce (with different skills) needed afterwards. The number of jobs created in electrolysis is highly uncertain, but assuming the operation is similar to basic chemical production, there would be around 1.6 jobs for every USD 1 million of output, which would lead to about 12 500 jobs for operation of the electrolysers once full capacity has been reached.

Nearly 35% of the jobs are in manufacturing alone, which will most likely be located abroad. More jobs are created for the manufacturing of components for onshore wind turbines than for their construction, and most of Ukraine's renewable potential is in the form of onshore wind (see Chapter 1. "Taking stock of the effect of war"). The share of trade in global deployment is about 20% given that the components are bulky and heavy. Europe is a mature market, with over 80% of the nacelles, blades and towers for onshore wind being manufactured domestically. Ukraine could benefit from its proximity to this leading market and import components from Europe.

More than 80% of the potential jobs are from renewables rather than electrolysis. Manufacturing and construction of the electrolyser could be in the order of 1 350 jobs per GW, while this could be 4-5 times higher for onshore wind. This is considering an optimistic scenario for job creation, while other estimates are closer to 500 jobs per GW. Operating the electrolysers is much more complex and labour-intensive than operating the renewable assets, but given the larger share of labour needed for manufacturing and construction of the renewable assets, most of the jobs are still associated with the renewable assets rather than electrolysis. As such, if job creation is a major policy goal, the greatest gains can be made by pursuing the expansion of renewables, which will be needed to realise the electrification plans of the long-term energy strategy and which would also result in a higher system efficiency.

The number of jobs to be created is highly uncertain, depending on the methodology used and specific assumptions. A recent review of 121 studies on job creation across all power generation technologies found that for the construction and installation of solar PV, the difference between the studies with the least and most jobs created was a factor of 5.5, decreasing to a factor less than 2 for the manufacturing stage. For onshore wind, those two numbers were roughly 2 and 3, respectively. For hydrogen, the uncertainty across literature is higher, given that studies are unclear regarding the scope (parts of the supply chain that are covered), type of jobs (direct and indirect), and stage (construction vs operation). Most studies with a comparable scope would create between 2 500 and 5 000 direct and indirect jobs in manufacturing and construction per GW of electrolyser capacity. Another uncertainty is introduced by regional differences for wages and investment, and how these affect the specific job multipliers for

Ukraine. Given these uncertainties, the numbers above should be taken as an indication of the order of magnitude rather than an accurate estimate of the number of jobs created.

Most of the jobs associated with production are for engineers and technicians, where there is a shortage in Ukraine. According to a PwC study,[24] 20% of the jobs associated with hydrogen production are for engineers, nearly 40% for technicians, and 30% in corporate roles. These are precisely the areas where there is a shortage of staff in Ukraine (see Chapter 1. "Taking stock of the effect of war"). Some of the roles that require the most hydrogen-specific knowledge are for chemical, commissioning and grid connection engineers, as well as managers and process control technicians, and in jobs related to safety and quality. At least half of the roles would require some general knowledge about hydrogen properties, equipment and safety. Specialised knowledge is required for operation of electrolysis and its cooling system.

There are alternative pools of human capital that could be tapped into. Ukraine and Germany have together agreed to open "Unity Hubs". These are centres aiming to provide advice to Ukrainians abroad, including support for a voluntary return to Ukraine and help with finding jobs. A post-war programme for (re)training of war veterans in renewable- and hydrogen-related areas could also be considered.

Finance

Producing 2.5 Mtpa of hydrogen would require an investment of about 50% of the 2024 GDP. This level of output would require about 25 GW of electrolysis and either about 45 GW of onshore wind or 125 GW of solar PV. For reference, the total pre-invasion generation capacity was about 44 GW, which plunged to 20 GW in 2024 (see Chapter 1. "Taking stock of the effect of war"). Installing 125 GW of solar PV would take a developed market like the United States more than 4 years at the deployment pace in 2024 (30 GW). This would be approximately equal to ten of the full-scale hydrogen valleys being currently planned. The investment need for such facilities (including renewables) would be in the order of USD 85-90 billion,[25] with nearly two-thirds of this going to renewables. This expenditure would not happen in a single year, but instead be spread over several years, but notably, this would be roughly equal to half of the USD 180 billion of GDP in 2024. As such, the investment needed for hydrogen

[24] Based on the oil and gas industry in Australia.

[25] Assuming 5 000 hrs/yr for the electrolyser, 67% efficiency on a lower heating value basis, CAPEX and average capacity factors from (DEA, 2024). Solar PV with USD 680/kW in 2023 and 993 full-load hours and onshore wind with USD 1 250/kW and 2 803 full-load hours. CAPEX decreases over time with deployment. Renewable capacity is sized based on operating hours, efficiency losses and targeted hydrogen volume.

alone would be 45-65% higher than the total investment needed to reconstruct the **entire** energy system after the war (see Chapter 1. "Taking stock of the effect of war").

Interest payments could amount to USD 165-175 billion (in nominal terms) with a cost of capital of 15%. Once the war ends, the cost of capital is expected to return to lower levels as the country risk premium decreases. Assuming a cost of capital of 15%,[26] the total interest payments (assuming a lifetime of 25 years) would amount to nearly twice the investment needs for hydrogen production. Annual interest payments could reach a peak of more than USD 12 billion. In comparison, direct investment in the entire Ukrainian economy was USD 7.5 billion in 2021, and gross international reserves were USD 31 billion. Some caveats are, firstly, that the cost of capital will most likely come down as experience is developed, and secondly, the capital expenditure will be carried out over several years with variable WACC, and projects could also be re-financed, meaning that some of the capital might not be exposed to such a high cost of capital. However, the high WACC premium in Ukraine can have a significant effect on annual flows and balance of payment, given the size of the investments required. Moreover, much will depend on how the WACC evolves over time and changes to the country risk premium after the war ends. The WACC might also be lower by the time most of the hydrogen deployment takes place, or if development finance and risk mitigation instruments are used (see Chapter 3. "Unlocking the opportunity - A roadmap for action"). If the WACC were reduced to 5%, the interest payments would be reduced to USD 55-60 billion.

[26] This is higher than the 12% seen pre-invasion for renewables due to an additional technology risk premium for electrolysis and additional hydrogen risks like offtake and infrastructure.

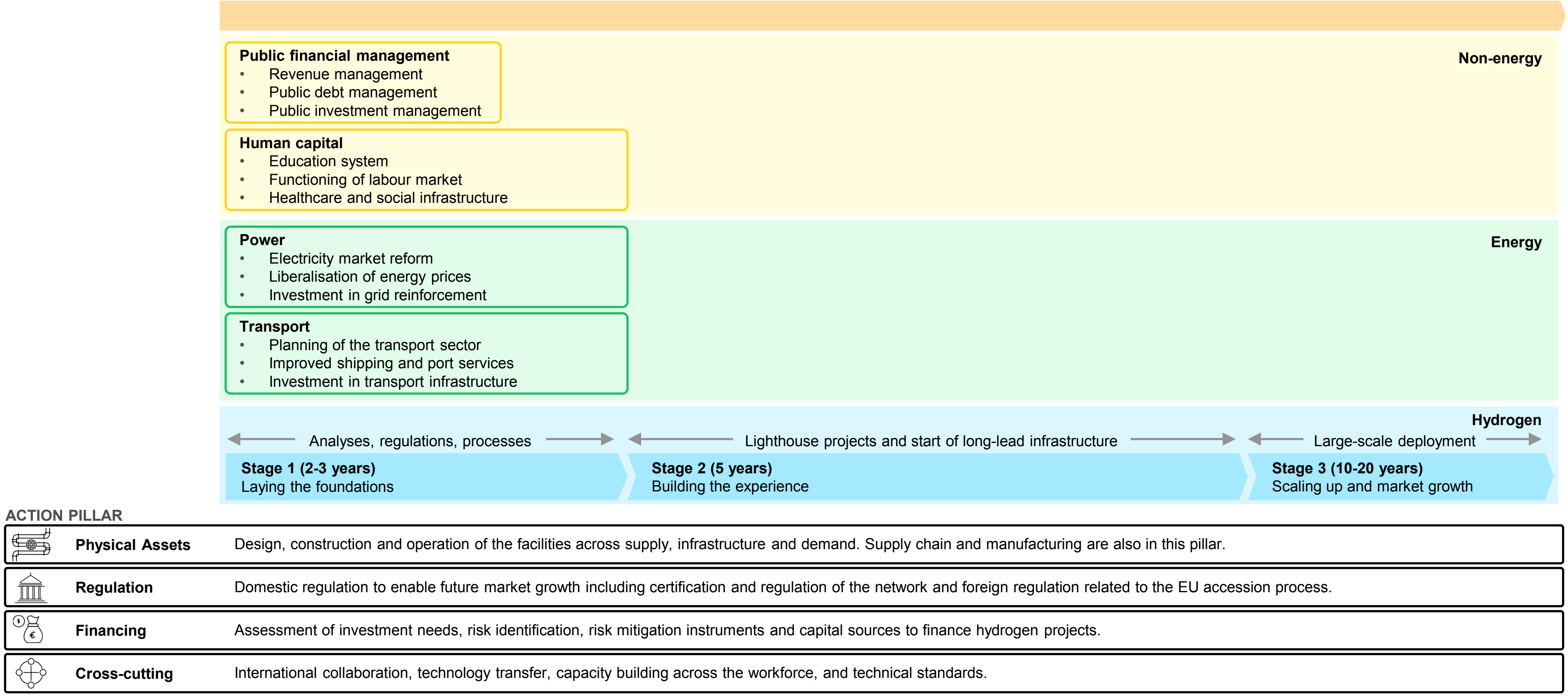
Unlocking the opportunity – A roadmap for action

Highlights

- Hydrogen represents a long-term opportunity for Ukraine, but action is required in the near term to unlock the full benefits. Work over the first 2-3 years after the war ends can lay the foundations for future market growth without large commitments, such as through studies, planning for regulation and de-risking. In a second stage (5 years) pilot projects would be built to develop experience in the private sector and inform policy. A final stage (10-20 years) would incorporate lessons learnt, with a focus on standardisation, replication and simplification to support large-scale deployment. Each stage will require action across four pillars: physical assets, regulation, financing and cross-cutting aspects.
- Physical assets cover supply, infrastructure, demand and the supply chain. Priorities include developing "lighthouse" projects and hubs to demonstrate the integration of various technologies, facilitating offtake for projects through policy or financial support and matchmaking platforms, leveraging existing gas infrastructure and de-risking the supply chain. This requires a progressive approach to deployment that reflects the interconnected nature of the assets.
- For regulation, providing clarity on legislation that will be applicable to hydrogen is a priority, as is harmonisation with EU legislation through the accession process, which could have positive effects for hydrogen development. Also needed is a certification scheme including methodology to measure GHG emissions, governance, scope, chain of custody and requirements.
- Priority actions for financing include tackling the risks resulting from the war, assessing investment needs across the entire value chain, considering uncertainties in cost evolution, innovation and learning, and identifying potential capital sources that could be used at different stages. Blended finance instruments and action to mobilise private capital will be essential as capacity starts to ramp up.
- Several cross-cutting aspects will play a role in development, including international collaboration and knowledge-sharing, such as through joint projects and platforms. A skilled workforce is needed in government, the private sector and research. Lastly, defining technical standards across the value chain and ensuring compliance will be key.

Hydrogen and its derivatives could offer a valuable opportunity for Ukraine in the long term. Taking advantage of this opportunity will require action outside and within the energy sector (see Figure 3.1) to improve the business case for hydrogen projects. Looking at the economy, improving revenues and public finance and debt management will be crucial to balance the public budget and enable the necessary investments in reconstruction. From the perspective of restoring energy supply, the power sector must be a key priority in order to ensure energy security and capacity adequacy. From the lens of decarbonisation, hydrogen has a key role to play in sectors where emissions are harder to abate, while initial efforts on decarbonisation are needed in the power and heating sectors. As Ukraine's economy and energy system recover from the war period, a continual reassessment of the state of the hydrogen industry will be needed, with an eye on progress, milestones and actions to be taken based on the latest developments.

Figure 3.1 Stages for hydrogen development within the broader context of (non-) energy measures



Source: IEA analysis based on data from the European Commission (2024) for non-energy and energy areas.

In the short term, areas other than hydrogen are critical for Ukraine. Hydrogen development could take place in three distinct stages over the coming 20 years and beyond.

A three-stage process for hydrogen development

Hydrogen development in Ukraine could take place in three distinct stages (see Figure 3.1):

1. **Laying the foundations (2-3 years)**. During this period, efforts would be focused on starting the reconstruction of Ukraine's energy system. This would include making regulatory changes to enable renewables deployment and support decarbonisation, such as power market reform and energy price liberalisation. For hydrogen, this period can be used to analyse the techno-economic feasibility and define relevant regulations that can provide clarity for investors, and to put in place processes like permitting and certification that will be needed for hydrogen development. The business environment may not yet be conducive to hydrogen deployment, but expansion of renewables to improve security of supply would serve to de-risk investment and develop confidence among project developers and financial institutions that will be useful for renewable hydrogen in subsequent stages. There is limited capital commitment at this stage, but the preparatory work undertaken will be essential for future market growth.
2. **Building the experience (5 years)**. At this stage, attention turns to beginning to execute some of the plans from the previous stage, experimenting with different configurations, players, policies and identifying what works in the national context. As much as possible, processes will be standardised during this place to enable large-scale deployment at the next stage. By now, policy incentives are in place to promote renewable hydrogen supply, the suitability of the existing gas infrastructure for repurposing to hydrogen has been assessed, and plans for the use of pipelines are starting to be executed. Pilot projects of increasing size are being undertaken, the certification scheme is fully in place with criteria that are harmonised with the European Union and recognised bodies, and the critical hydrogen-related EU policies from the EU accession process are now part of the national legislation.
3. **Scaling-up and market growth (10-20 years)**. During this period, all the processes are fully established and standardised, planning is clear and lessons learnt from the earlier stages have been implemented. This stage is characterised by replication and scaling-up, undertaking large-scale projects, achieving economies of scale and driving down costs. There is a mix of domestic use for industrial applications and exports. There is visibility on cost competitiveness and the outlook for phasing out incentives. The power sector and market are now mature and there is experience from the pilot projects for renewable hydrogen. Certification now covers hydrogen derivatives like steel and ammonia, and has also expanded to cover non-GHG aspects like water consumption, land use and social aspects.

Devise a strategy for physical assets and supply chain integration

Figure 3.2 Activities across stages for the physical assets pillar

Priority: High Medium Low

Sub-category	Stage 1 (2-3 years) Laying the foundations	Stage 2 (5 years) Building the experience	Stage 3 (10-20 years) Scaling up and market growth
Supply	• Establish **production targets** for various time horizons • **Assess production pathways** from a GHG, sustainability and equity perspective • **Identify** the most suitable **policies to promote the ramp-up of renewable hydrogen** and factors to consider for each one • Provide support to initiate **feasibility studies** for small-scale electrolyser projects • **Design a competitive bidding scheme** for renewables and integrated production with hydrogen • Estimate **supply cost curves** for renewable hydrogen • Assess the cost, potential and timeline for **hydrogen** from nuclear power	• Use a **mix of CAPEX and OPEX incentives** to close the cost gap • Assess the possible use of **output-linked production incentives** • Establish a **platform to disseminate lessons** from small-scale projects • Provide support to initiate **feasibility studies** for small-scale electrolyser projects • Assess the cost and potential to **produce hydrogen derivatives** (e.g. ammonia) • Put in place a system to **monitor performance** and effectiveness of public funding of projects • Assess the cost and **potential to export** hydrogen through **shipping routes**	• Standardise and **optimise design** for large-scale plants to enable low-cost replication • Define **timeline for incentives phase-out,** considering market developments • Support the **construction of large-scale** hydrogen derivatives plants
Demand	• Assess **market potential for domestic uptake** and willingness to pay by sector, considering**:** - Effect on prices of final goods - Effect of integration with EU policies - Transition plans from industry • Identify the best applications to stimulate demand including **low-regret uses** • Establish **matchmaking platforms** to bring supply, infrastructure and demand players together • Identify **hubs** with multiple neighbouring hydrogen users that could benefit from economies of scale • Map **geographical (mis)match** between demand centres and regions with low-cost renewables	• Consider a **mix of CAPEX and OPEX incentives** for the different end uses • Put in place **price and volume incentives** to promote hydrogen uptake • Establish a platform for **price transparency** using auctions and bid data • Assess the possibility of **subsidy stacking** to improve the economics of hydrogen use • Consider the use of **public procurement** to drive demand for low-emissions steel • Assess the cost and **potential to export** hydrogen through **shipping routes**	• Define **timeline for incentives phase-out,** considering market developments • Support the hydrogen uptake at **large scale** in domestic ammonia and steel plant
Infrastructure	• Assess state of **natural gas pipelines and material suitability** for repurposing to hydrogen • Undertake integrated planning and **feasibility studies for cross-border pipelines** to the European Union • Carry out **risk** and suitability assessment for repurposing **natural gas underground storage sites** to hydrogen • Undertake **power grid expansion planning** considering electrolyser load and increased load form electrification • Carry out **planning of domestic pipelines** based on prioritised applications and cross-border pipelines • Assess **underground storage needs** considering demand forecast and resilience • Identify **projects** that could be proposed as **EU Projects of Mutual Interest (PMI)** in the next cycle	• **Construct pipelines** between major supply centres and no-regret uses • **Construct cross-border pipelines** • **Repurpose natural gas pipelines** considering gas outlook and network development plan from previous stage • **Construct underground storage** at locations defined in previous stage • **Repurpose natural gas sites** considering gas outlook and network development plan from previous stage • Expand **power transmission network** to unlock flexibility from electrolysers • **Adjust construction timelines** based on market developments • Expand **port and on-site storage capacity** for hydrogen derivatives (as needed)	• Expand underground storage capacity to ensure **security of supply** • **Expand network** to smaller hydrogen uses

Priority: 🔴 High 🟡 Medium 🟢 Low

Sub-category	Stage 1 (2-3 years) Laying the foundations	Stage 2 (5 years) Building the experience	Stage 3 (10-20 years) Scaling up and market growth
Supply chain	🔴 Perform **risk assessment** of supply chains for renewables and hydrogen technologies 🔴 Assess the **impact of trade barriers** on hydrogen equipment cost 🟡 Identify alternative suppliers (across countries and companies) 🟢 Establish **partnerships** with **countries** that have large manufacturing capacity (plans) and **electrolyser OEMs**	🔴 **Remove trade barriers** including non-tariff measures 🟡 Track sourcing of materials, components and equipment to contribute to **market transparency** 🟢 Promote the use of **domestic sourcing for conventional equipment** (e.g. vessels) 🟢 Assess the possibility of **domestic manufacturing** for each component and technology	🟡 Perform **regular risk assessments** to ensure diversification of supply

Activities under the physical assets pillar target supply, demand, infrastructure and the supply chain.

Stage 1 (2-3 years)

Supply

Establish targets; identify policy incentives; assess cost, emissions and feasibility. During this early phase, a detailed assessment of the production pathways can be made, covering cost, emissions and sustainability. Feasibility studies for specific locations can be undertaken with a view to deploying pilot projects in the next stage. From a policy perspective, the vision and long-term targets could be defined, as well as the short-term policy instruments that will be used to achieve this vision. Schemes used for renewables could be expanded to hydrogen. Competitive bidding schemes, like auctions, have been successfully applied in other geographies. These combine competition that can drive down the cost (and reduce the extent of public support) with price discovery, which is crucial at this early stage when there is no market and no price index. A bottom-up assessment of the electrolyser cost would help build understanding of how aspects like domestic labour cost; engineering, procurement and construction (EPC) companies; and transport cost affect the total installed cost for Ukraine. By this stage, reconstruction plans would be clearer, allowing for an assessment of potential resource competition between electrolysis and other activities, especially for water withdrawal and consumption. Similarly, the ramp-up of electrification at the local level would enable comparison between the supply cost curves for renewables and the electricity demand from electrolysis and other sectors.

Demand

Quantify market potential and willingness to pay of hydrogen users and identify hydrogen demand hubs. The cost gap is one of the most important barriers in early stages of development. While it can be closed through incentives, there may be some users who have a higher willingness to pay (WtP). This could be a result of high energy prices for the counterfactual commodity, companies' decarbonisation targets or strategy diversification, for example. This stage would encompass assessment of the WtP of different users and the potential volumes they could take over time, in order to build a demand-cost curve. Based on this, a prioritisation of renewable hydrogen use among sectors could be developed, considering the geographical match with supply and co-location of users to take advantage of economies of scale. A matchmaking platform has been useful in other regions for connecting different actors, which facilitates the emergence of new projects and exchange of lessons learnt, and increases the awareness of new initiatives and ideas, thereby supporting innovation.

Infrastructure

Assess suitability of existing (cross-border) pipelines and underground storage sites for hydrogen. Ukraine has vast gas infrastructure that could be repurposed for hydrogen, which would drastically cut the costs of transport and storage. During this stage, an assessment of the pipeline materials would be made, including their susceptibility to hydrogen embrittlement, and the possibility of changes in operating conditions or practices that would enable hydrogen transport. Once the most promising interconnection points are identified, these could be proposed as EU Projects of Mutual Interest (PMI) in order to facilitate administrative process and access EU funding sources (such as the Connecting Europe Facility). The pipeline corridor from Ukraine to Slovakia, the Czech Republic, Austria, and Germany was already proposed in the first PCI/PMI list from November 2023, but other corridors could be proposed, or this proposal could be renewed. An assessment of the current gas storage sites would be made, quantifying the risk of contamination, hydrogen losses and potential cost of purification (if needed). The specific pipelines that would be used to connect the hydrogen supply centres with the demand hubs, and cross-border pipelines, would be identified and planned in an integrated way that incorporates the expansion planning of the electricity, gas and hydrogen networks.

Supply chain

Map potential supply chains for hydrogen equipment and identify alternatives for de-risking. This stage entails identifying potential suppliers for renewables assets, electrolysis, and balance of plant, improving understanding of risks that could compromise supply, and specifying measures that could be used to mitigate those risks, including identifying alternative suppliers. For example, China was home to more than 80% of the installed solar PV manufacturing capacity in 2023 and utilisation of manufacturing facilities was just 40%. Any risks related to market consolidation, supply disruption, or trade measures could affect both the cost of the equipment, which would affect the levelised cost of hydrogen, and the project execution timeline, which would affect the returns. In contrast, a large share of the renewable potential for Ukraine is from onshore wind, for which Europe has robust manufacturing capacity, with shorter transport distances and lower chances of disruption. Establishing agreements with large, established companies with a track record of deployment (in other regions) could be a way to reduce supply chain risks.

Stage 2 (5 years)

Supply

Refine policy incentives, implement lessons from pilot projects and plan large-scale projects. By this stage, there would be some lessons from the construction of small-scale projects that can be incorporated into feasibility studies and cost assessments of large-scale projects. From the policy perspective, there would be a mix of incentives aiming to close the cost gap, with support for both CAPEX and OPEX. These may allow for subsidy stacking, depending on the type and degree of incentive. The policy instrument used should strike a balance between fiscal efficiency and production reliability and quality. A monitoring system would have been put in place to keep track of the performance of pilot projects and progress towards established targets, as well as a single repository of lessons learnt. Ideally, data from pilots, both for the total public support and operational data, would be publicly available, which would contribute to better cost estimates, price and market formation, and reduce the uncertainty of the business model. Feasibility studies for large-scale projects would be ongoing, considering various hydrogen derivatives, domestic use and export.

Demand

Promote demand creation through a mix of financial incentives, demand hubs and public procurement. As discussed in Chapter 1 ("Taking stock of the effect of war"), domestic hydrogen demand has plunged 80% due to Russia's full-scale invasion. The low-emissions hydrogen route comes at a premium for ammonia and steel (see Chapter 2. "The hydrogen opportunity"), so additional financial incentives could contribute to closing the cost gap at this early stage when there is limited technology learning. The cost gap could also be addressed in part by using reconstruction as an opportunity to plan industrial hubs that co-locate several hydrogen users, and even supply, to reduce infrastructure costs. Policy instruments targeting the volume component, like quotas, could also be used to provide greater market certainty to supply projects. Another opportunity from reconstruction comes from the vast public infrastructure that will be needed: It has been estimated that reconstruction would trigger steel demand of nearly

66 Mtpa. If reconstruction is carried out over 20 years, this would be equivalent to about 15% of the annual domestic production prior to the invasion. A large share would be for buildings where public procurement and building codes could play a role in promoting the use of low-emissions materials without having a major impact on the final price of the finished building. As an example, in the European Union, public procurement represents 14% of GDP and approximately 1.4% of GDP is allocated to the construction sector. This is expected to be much larger for Ukraine during the reconstruction phase.

Infrastructure

Support construction and/or repurposing of domestic and cross-border pipelines and expand port capacity. Pipelines, underground gas storage facilities and port terminals have long lead-times, which for gas are between 6 and 12 years. As such, for them to be ready at full capacity in the last stage, detailed planning and project execution would need to start at this stage. Feasibility studies and material assessment were part of the previous stage, so here the focus is on execution. If most of the hydrogen infrastructure can use repurposed assets, the timelines may be shorter, but there would be additional steps like sampling, testing and equipment certification. Similarly, if renewables and electrolysis are not co-located, grid reinforcement, or even new lines, might be needed. These also have long lead-teams, so work should begin at this stage. Port capacity should also be expanded as needed, based on both potential export of hydrogen derivatives by ship and the potential import of large equipment (e.g. for onshore wind) for the large-scale deployment of the next stage.

Supply chain

Diversify the supply chain, track components and assess possibility of domestic manufacturing. A diversified portfolio of suppliers from different companies, countries and transport routes would decrease the impact of disruptions and potential delays. Tracking all the components that go into the clean energy equipment would build up the data needed to ensure that technology supply chains are secure, resilient, and sustainable. While domestic manufacturing might be difficult in the first stage, given the additional investment, skilled labour, industry knowledge and cost competitiveness required, by now, following some renewable deployment, Ukraine could consider manufacturing certain equipment. This would depend on the progress of reconstruction and imports might still be a good strategy. To facilitate this, the removal of trade barriers, as far as possible, would be beneficial for cost competitiveness. Equipment that requires little specialisation, like compressors, pumps and meters, could be domestically sourced during this stage.

Stage 3 (10-20 years)

Supply

Support construction of large-scale hydrogen (derivatives) plants and start to phase out financial incentives. By this stage, all the incentives would be in place, and there would be experience on both the construction and the regulatory side. Processes would now be standardised, from project planning and execution, to administrative regulatory processes like permitting and certification. This would allow for predictability in timelines, higher certainty of project execution and lower risks, translating into higher confidence from investors and a lower cost of capital. This also opens a broader range of capital sources, including long-term investors willing to initially accept lower returns. Limited changes would be introduced from one big project to the next, allowing for replication and cost reduction through technology learning. Equipment would be as modular as possible, with reduced on-site construction enabling faster construction periods and earlier revenue generation. At some point during this stage, when costs start to come down, financial incentives would start to be phased out. This coincides with the steep ramp-up of production, when financial incentives would be significant compared to the fiscal budget.

Demand

Leverage domestic users to anchor hydrogen demand for large-scale projects. If the pre-invasion capacity for ammonia and steel is restored, hydrogen-based processes would allow to build back with lower emissions. In addition, they could also help provide economies of scale, thereby improving the business case for large supply projects. Domestic industrial demand could complement export projects, allowing for larger scales, and provide more certain demand closer to the supply centres. When the emissions tracking from the previous stage is implemented, there might be a premium that can be claimed. By this stage, there should be several buyers willing to pay such a premium given that deep decarbonisation of industrial sectors is expected in importing markets. Uses with smaller typical volumes, like fuel cell trucks, would also benefit from these industrial hubs.

Infrastructure

Expand storage capacity to ensure security of supply and expand the hydrogen network. By now, large volumes of hydrogen would be produced and used, which would enable central planning of the system rather than optimisation of the individual assets. Security of supply for the system can be achieved by using underground storage with large volumes, taking advantage of their lower cost by volume. This stage could also see the expansion of the hydrogen network beyond the main transmission lines. This would be justified by the industrial hubs and export, but there might be additional (smaller) uses that could also make use of the main network.

Supply chain

Perform regular risk assessments to ensure diversification of the supply chain. Clean technology supply chains should now be mature and diversified. However, new risks might have emerged that require a reassessment of sourcing, and additional measures to ensure secure and robust supply chains for all the clean technology equipment used for renewable hydrogen.

Establish a clear, predictable and supportive regulatory framework

Figure 3.3 Activities across stages for the regulation pillar

Priority: ● High ● Medium ● Low

	Sub-category	Stage 1 (2-3 years) Laying the foundations	Stage 2 (5 years) Building the experience	Stage 3 (10-20 years) Scaling up and market growth
Domestic regulation	Legislative framework	● Identify all the **legislation** that would need to be **amended** to consider hydrogen and gaps where new laws are needed ● **Permitting**: - Dedicated areas with pre-clearance for RES development - Standardised permitting process application documents - Centralised permit-granting authorities ● Establish a **single government body** responsible for all hydrogen-related laws and regulations ● Identify the **policy instruments** that are most suitable within the national energy context to **support the critical parts** of the value chain ● Identify the **parts** of the hydrogen value chain where **public support is most critical** ● Revise **carbon tax price trajectory** to promote hydrogen uptake in domestic industry	● **Amend legislations mapped** in previous stage to account for hydrogen ● Design a **competitive power market** to reduce prices and reward electrolyser flexibility ● **Implement** most suitable **policy instruments** by part of the supply chain ● Align **ETS targets** with net zero trajectory to promote high carbon prices ● Extend legislative coverage to **hydrogen derivatives** ● Define **intermediate milestones towards net zero** across hydrogen-related legislation to provide visibility to investors	● Incorporate the value of **long-duration energy storage** in the power market
	Hydrogen network	● Assess **alternatives for the governance** and oversight of the transmission network ● Define how the network will be regulated in terms of **unbundling, third-party access** and if there are phases of implementation ● Assess **alternatives to finance** the network and set tariffs over time ● Define regulation and transitional periods for **repurposed natural gas infrastructure** ● Specify **technical and quality standards** compatible with EU regulation	● **Align** domestic regulation of the hydrogen network **with EU regulation** ● Integrate long-term planning of **hydrogen** network with **power and gas** infrastructure ● Implement a finance mechanism that considers the **lower utilisation** of the network in **early stages** of deployment ● Consider making **finance and tariff-setting** methodology and data **publicly available** ● Apply cost-reflectivity to **avoid cross-subsidisation** of network users ● Revise transitional periods in regulation based on **market developments**	● Complete **unbundling of the gas and hydrogen** networks

Priority: 🔴 High 🟡 Medium 🟢 Low

	Sub-category	Stage 1 (2-3 years) Laying the foundations	Stage 2 (5 years) Building the experience	Stage 3 (10-20 years) Scaling up and market growth
Domestic regulation	**Certification**	🔴 Define **methodology to measure GHG emissions** from hydrogen supply chain (aligned with ISO methodology) 🔴 Define **sustainability criteria** and conditions for hydrogen supply chain 🔴 Implement a **certification scheme through legislation** 🟡 Identify changes needed in the power sector to track **hourly emissions intensity** of the grid 🟢 Evaluate if current **auditing body** for electricity could also cover hydrogen Guarantees of Origin (GO) 🟢 Perform a **gap assessment** for the use of EU-approved certification schemes 🟢 Perform a gap assessment for the use of **digital technologies** to track, verify, and certify emissions 🟢 Determine if **GO scheme for electricity** can by **expanded** to hydrogen	🔴 Transition to **granular tracking of GHG** emissions 🔴 Ensure **interoperability** with ither certification schemes 🔴 Establish a **digital platform** as a registry to track all the hydrogen emissions 🟡 Revise certification scheme with **latest internation standards** for measuring GHG and other sustainability criteria 🟡 **Expand** certification scheme **to pipelines** and consider mass balancing 🟡 Revise certification scheme criteria based on **market developments** 🟢 Expand certification scheme to **hydrogen derivatives** including carbon-containing carriers 🟢 Ensure **alignment between certification schemes** of hydrogen, gas, and power 🟢 Expand **emissions tracking** from hydrogen derivatives **to downstream products** 🟢 Consider making **GHG emissions data publicly available**	🔴 **Revise GHG thresholds** certification scheme in line with net zero pledge 🔴 **Revise sustainability criteria** to ensure alignment with Sustainable Development Goals (SDG)
Foreign regulation	**Integration with EU polices**	🔴 Identify all the existing **legislation** that would need to be **amended** to adopt the EU policy framework 🔴 Perform an **impact assessment** of integration with EU policies, specifically the ones for hydrogen: - Hydrogen and Decarbonised Gas Package - Renewable Energy Directive - Emissions Trading Scheme and Carbon - Border Adjustment Mechanism - Standardised permitting process - ReFuelEU Aviation - FuelEU Maritime 🟡 Specify a **transitional period** for full adoption of policies	🔴 Perform an impact assessment of integration of **European Union's 2040 policy package** 🔴 Co-ordinate **long-term planning** of the hydrogen networks with EU Ten-Year Network Development Plan 🟡 **Design and establish new policies** that might be needed to cover new areas introduces by EU legislation 🟡 Align **technical standards and regulations** with EU transmission system operators 🟢 Consider impact of EU **energy security policies** on hydrogen storage needs	🔴 Ensure compatibility with the **European Union's net zero trajectory** considering domestic targets and constraints 🟡 **Design and establish new policies** that might be needed to cover new areas introduced by EU legislation

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Most activities under the regulation pillar are related to domestic regulation, but the EU accession process could also introduce incentives for hydrogen uptake.

Stage 1 (2-3 years)

Legislative framework

Identify laws that would require changes for hydrogen and establish a simplified and centralised administrative process. The first step is to map any existing legislation covering hydrogen (e.g. as an industrial gas) and identify the changes needed for its use as a fuel and feedstock. This has been done in Australia, for example, where existing acts, standards and policies across the gas supply chain were mapped to identify potential barriers in scope and coverage for the uptake of sustainable fuels. Another approach is to take a specific project and map all the administrative steps and documents needed by project stage. An example is from the H2Uppp programme, which did this for ammonia in Mexico. It is important to identify the government agencies and departments involved in each of these processes, with the aim of centralising the process and ideally developing a single entry point for project developers to use for the entire process rather than having to apply to different agencies. Government agencies have been mapped in the United States. The concept of a one-stop shop has not been fully implemented in any country, but a centralised overview of all the funding opportunities has been developed in Germany and the Netherlands, for example. Permitting for renewables projects has delayed project timelines in developed markets. Ensuring this is standardised and expedited would help to de-risk hydrogen projects. Good practices are available, for example, from the European Union. This step would also be forward-looking, identifying any new legislation needed to promote hydrogen, and tailoring the choice and design of the instrument to the relevant part of the value chain.

Hydrogen network

Define the regulation of the hydrogen network including technical and quality standards. Governance and unbundling of activities are some of the aspects to consider. Vertical unbundling (separation of production from transmission) and horizontal unbundling (separation of gas and hydrogen transmission operation) are some of the design choices to be made at this stage. There could also be separation of ownership and operation of the network. Fees for accessing the network can be regulated with fixed prices or with negotiated prices between parties, with more freedom on contract conditions. The choice will affect the role of the regulatory authority in this process, as well as competition and price. Financing and cost recovery should also be part of the regulation. An asset base with regulated returns (like in the United Kingdom or Germany) with a regulated return could be an option. The design should also take into account lower utilisation during early phases: some options include subsidies or a tariff deferral system, with some of the early losses compensated by higher revenues later. These choices do not have to be fixed over time, and the regulatory framework can be adapted to market maturity and network size. Changes to regulation could be defined either based on a clear timeline or based on indicators or milestones (e.g. transported flow). Exemptions might also be considered for pipelines that are too small, short, or between two specific assets. In either case, it will be important to define a set of principles at the beginning to guide the subsequent decisions. These include predictability, transparency, non-discrimination, monitoring and oversight by a regulatory authority.

Certification

Establish a digital hydrogen certification scheme, ensuring consistency with the European Union. There are several aspects to consider in the design of the scheme. First is the methodology to measure GHG emissions, including boundaries of the system, allocation of co-products, and consideration of supply chain emissions, among other aspects. Ukraine could consider using the existing ISO Technical Specification that defines all these aspects, and which will turn into a set of full standards over 2025/2026. Within the scope definition, the system could include hydrogen derivatives, which could be an attractive way for Ukraine to export hydrogen. Second, define the sustainability criteria and whether anything beyond GHG emissions (e.g. water) will be included, and the standards that will be used to measure those parameters. Third, governance, including the roles and responsibilities of the accreditation body, the certification body and the scheme owner. Fourth, the rules for issuing, trading and cancelling certificates. This also includes the registry of certificates and the auditing process. Fifth, the chain of custody model which defines the correspondence in trading the certificates and the actual molecules. Sixth, Ukraine could consider the adoption of digital technologies for the issuing and tracing of certificates, including blockchain and digital passports. These could improve the accuracy, accountability, automation, scalability, transparency and security of the system. Lastly, Ukraine could consider using some of the certification schemes already approved by the European Union. This would ensure consistency and recognition by the European Union, thereby facilitating trade.

Integration with EU policies

Assess the impact of the EU accession process and identify legislation that would need amendment. Ukraine applied for EU membership in February 2022 and started negotiations in June 2024 as part of a broader process across the entire economy. For hydrogen demand specifically, there are quotas for renewable hydrogen in the Renewable Energy Directive (RED) (targeting industry and transport), FuelEU Maritime and ReFuelEU Aviation.[1] Being a Directive, RED would need to be transposed into national legislation, and there is some flexibility regarding the specific instruments that will be used to reach the targets. It also provides visibility until 2035. In contrast, the other two instruments are regulations, which mean they are directly applicable, and targets that extend to 2050. The Emissions Trading System (ETS) would also be useful to close the cost gap for industrial applications. Ukraine has a carbon tax of less than USD 1/t CO_2 (see Chapter 1. "Taking stock of the effect of war") and is planning to introduce an ETS in 2025, but adopting more ambitious reduction targets would contribute to higher carbon prices and a smaller cost gap for renewable hydrogen. ETS certificates traded at EUR 55-80/t CO_2 in 2024 and could reach levels of EUR 100-150/t CO_2 by 2030. This 2030 level would be equivalent to roughly USD 1-1.5/kg of cost penalty for the conventional gas route, and would therefore not close the cost gap on its own. The hydrogen and decarbonised gas

[1] ReFuelEU Aviation has a quota for sustainable aviation fuel (SAF) overall and a minimum sub-quota for synthetic fuel. FuelEU Maritime also has a GHG reduction target which could indirectly trigger demand for renewables although that is unlikely given the cost premium in the short term.

package defines the full regulatory framework for hydrogen networks discussed in the previous point, so adopting such a policy would simplify policy design and would also facilitate trade by pipeline.

Stage 2 (5 years)

Legislative framework

Amend existing legislation and put in place new policies to support hydrogen uptake. The legislation mapped in the previous stage would be amended at this stage. Similarly, the policy instruments that were designed during the previous stage would come into force during this stage, providing clarity to the private sector and paving the way for reaching scale at the next stage. On the supply side, the power market could compensate for the flexibility that electrolysers can provide. Hydrogen could act as energy storage and provide services like time shifting or load smoothing, but electrolysers could also act as a positive load ramping down the capacity when the residual load is high. The power market should be able to compensate the different forms of demand response and energy storage. Hydrogen storage is usually needed for the last share of decarbonisation and it is meant for longer durations that couple well with wind (while batteries are usually better for the daily cycles of solar PV). However, long-duration storage could also enhance the role of batteries. All of this will only be possible once the power market reform from the first stage has been implemented and the market allows for different market windows, and incentivises different types of flexibility. On the demand side, a high carbon price, either from the upcoming ETS or the existing carbon tax, would help to close the cost gap for renewable hydrogen use.

Hydrogen network

Integrate electricity and gas network expansion planning and compensate operators for lower utilisation. Large-scale electrolysis would start in the next stage, but if infrastructure planning is not co-located with renewables, it should start in this phase. This would be necessary for hydrogen pipelines and electricity transmission lines, both of which have long lead-times. Utilisation of the hydrogen should still be low by the end of this stage, so the mechanism to compensate network operators for lower utilisation should be in place. If Ukraine's gas infrastructure can be repurposed to hydrogen, then most of the capital investment will have already been written off, leaving the OPEX as the main driver of the transport cost, and no need for such compensation. Either way, the network tariffs should by cost-reflective[2] and, ideally, all the information regarding network financing and tariff-setting should be publicly available.

Certification

Expand the scope of the certification scheme, digitise and revise based on market development. If not already defined in the previous stage, this stage would expand the scope of the scheme to cover the transport step and hydrogen derivatives. Ideally, it would also expand the sustainability criteria beyond GHG emissions to cover aspects like water, land use and social criteria. This stage would transition (or at least provide a clear timeline for transition) to (sub-)hourly measurement of GHG emissions to increase the accuracy of measurement, but also to reduce the risk of increasing the system's emissions. By now, the scheme should be fully digitised in a single registry enabling the secure trading of certificates and access to the data. The scheme should be fully compatible with the EU schemes, with an automatic equivalence (if not the same). Ideally, the registry information would be publicly available to enable transparency and allow further analysis from civil society. Experience from the first stage would provide information on the feasibility of measuring and achieving the sustainability criteria, and whether a revision of the reduction trajectory is needed.

Integration with EU policies

Assess the impact of the European Union's 2040 policy package and align hydrogen network development. In February 2024, the European Commission set a target of 90% GHG emissions reduction by 2040. Based on the timeline for development of previous targets, the legislation for the 2040 targets could be in place by 2027-2028. The implications for hydrogen in Ukraine are twofold. First, more ambitious targets would trigger a larger hydrogen demand and a higher WtP in the European Union, making the case for export more attractive in terms of price premium and volumes. Second, if the EU policies are adopted as part of the accession process, domestic hydrogen demand could also be higher. With regards to infrastructure, every 2 years, the network transmission operators create a non-binding Ten-Year Network Development Plan (TYNDP) that provides visibility of the network flows and enables planning for capacity expansion or changes. Since 2018, a combined TYNDP has been developed by gas and electricity networks, given the increasing level of interaction between both systems. Ukraine could participate in such a process to ensure there is adequate capacity at the right time in the EU network for the export flows by

[2] Based on a margin over cost without taking advantage of the monopolistic nature for higher profits.

pipeline. Aligning with the European Union's energy security policy (e.g. days of gas – or, in the future, hydrogen – storage) would also be beneficial for Ukraine at this stage.

Stage 3 (10-20 years)

Legislation framework

Incorporate the value of long-duration energy storage in the power market. The power sector should be well on its decarbonisation journey by this stage, with high shares of renewables. At this point, the need for flexibility extends beyond hours and days, and seasonal variability becomes more important. Hydrogen can provide seasonal flexibility in two ways. First, by ramping up and down the electrolyser and changing the demand profile. Second, by coupling the electrolyser with storage and using the hydrogen for power generation during periods of low renewable generation. This pathway has a relatively low (21-27%) roundtrip efficiency, which means the initial electricity price will be multiplied by a factor of 4-5. The power market should be designed to promote these additional sources of flexibility, for example through a capacity market.

Demand

Unbundle the gas and the hydrogen networks. Hydrogen flows should be quickly ramping up during this stage, reducing the need for cross-subsidisation from the gas network and its users. Subsidies for low utilisation should be phased out during this stage, and there would be greater visibility of the ramp-up of volumes in view of the net zero targets for the system.

Certification

Align sustainability criteria with a net zero trajectory. By now the scheme would be fully in place and will have been continuously used. The main action would be to revise the sustainability criteria, especially the GHG emissions, to align with system-wide GHG targets and the net zero trajectory. This could be enforced by phasing out incentives for higher-emissions routes earlier or introducing (additional) penalties for those routes. Since the basic sustainability criteria should now be covered, alignment with the broader set of Sustainable Development Goals (or equivalent) should be sought.

Integration with EU policies

Revise legislation targeting a net zero trajectory, considering domestic constraints. With clarity on the 2040 policies, this stage would provide visibility on the path to net zero emissions. While the time horizon enshrined in the EU Climate Law is 2050, the point in time for Ukraine to reach this target may be different, based on the progress of the reconstruction process and other factors. New policies (e.g. carbon removal) might also be needed to achieve such a goal, so this stage would cover both the expansion of existing policies and drafting of new ones.

Financing the hydrogen opportunity: Capital sources and risk mitigation

Figure 3.4 Activities across stages for the financing pillar

Priority: High Medium Low

Sub-category	Stage 1 (2-3 years) Laying the foundations	Stage 2 (5 years) Building the experience	Stage 3 (10-20 years) Scaling up and market growth
Financial needs	• Assess **investment needs** for hydrogen uptake **by part of the supply chain** • Assess **potential effect of uncertainties** including technology learning, policy effects, supply chain disruptions • Identify **programmes** that could be used to **channel international funds** to specific projects and initiatives	• Update investment needs based on **real costs from small-scale projects** • Split **finance needs by risk profile** to be able to match to investors • **Update infrastructure costs** based on pipeline construction projects globally	• -
Risk mitigation	• Evaluate the use of **insurance of war risks** (e.g. as in Germany) • Work with development banks to identify **financial** instruments that can mitigate **political risk** (e.g. The Multilateral Investment Guarantee Agency from the World Bank) • Work with **financial institutions** to identify financial instruments to mitigate the **currency risk** (e.g. contract currency, FX forwards) • Perform a **risk assessment** for supply and infrastructure projects involving domestic and foreign private sector and civil society	• Determine the **effectiveness of measures** based on pilot projects and feedback from financial institutions • Establish a platform for **price transparency** using auctions and bid data • Assess the cost and **potential to export** hydrogen through **shipping routes**	• Perform an **ex-post analysis** of the effect of risk mitigation measures
Capital sources	• Map financial institutions' **risk profiles** to project types • Consider setting up a **dedicated fund for reconstruction** with mixed capital sources • Identify the **development finance** that could be expanded to cover **hydrogen** • Evaluate the **leverage ratio** of different **financial institutions** • Estimate potential foreign **private capital** that could be triggered by policies based on project pipeline and corridors • Assess **share of debt** that could be used for different parts of the value chain considering risk mitigation instruments • Assess potential **public funding** that could come from the European Union (e.g. PMI)	• Establish **blended finance mechanisms** to bring public and private capital together • Enable the use of special purpose vehicles and **project finance** • Establish **dedicated financing initiatives** for low-emissions hydrogen • Promote the use of **foreign direct investment** in hydrogen projects • Consider the use of **results-based finance** and guarantees to reward best performers • Develop a **finance taxonomy** aligned with international standards	• Promote the use of **private capital and debt** to finance hydrogen projects • Enable hydrogen **TSOs to self-finance** network expansion

Financing hydrogen deployment requires quantifying the capital needed, identifying the potential sources and mitigating the project risks.

Stage 1 (2-3 years)

Financial needs

Assess the investment needs for the hydrogen supply chain, uncertainties and potential funding programmes. A complete assessment of the investment needs would be carried out at this stage, to understand potential uncertainties from current capital costs (which still correspond to a first-of-a-kind plant) and the cost reduction potential from innovation, learning and economies of scale. Considering the export case by pipeline, a big uncertainty lies in the possible use of existing cross-border gas pipelines based on their material and condition, but that should also be cleared at this stage (see "Infrastructure" section). Estimates for the entire supply chain allow for an order of magnitude estimate of the capital needs, but a more accurate estimate will be needed for the first pilot projects of the next stage. In parallel, mapping the potential risks associated with the capital deployment would allow for identification of risk mitigation instruments and matching with capital sources that seek a similar risk profile.

Risk mitigation

Identify risk mitigation instruments that can address war and political risks. There are currently three types of organisations covering these risks. First, among international financial institutions, the World Bank has provided USD 215 million of coverage against war risk since 2022. Part of the support was the launch of a specific trust fund for political risk insurance (and credit enhancement) that was worth USD 114 million by October 2024, which could grow to USD 300 million. Second, development finance institutions can also provide insurance to mitigate war risks. For example, the development finance institution from the United States has committed USD 407 million for political risk insurance targeting manufacturing and agriculture.[3] The European Bank for Reconstruction and Development also launched a USD 113 million war risk insurance facility in November 2024, initially covering inland cargo, damage to motor vehicles, and railways. Third, Export Credit Agencies (ECA). For example, Bpifrance offers an insurance to French companies looking to invest in Ukraine, covering up to 95% of the investments and covering risks for property damage or political events. The Ukrainian ECA has been able to insure investments against political and war risks since the beginning of 2024. Its coverage of Ukrainian exports reached 45% (from 16%) in June 2024, and the ECA supported almost USD 200 million of exports in 2024.

Risk mitigation

Use credit enhancement mechanisms to decrease the risk of early investments. By October 2024, about USD 16.5 billion of financial guarantees had been committed by several governments. Only a fraction of this capital targets the energy sector, but it is an example of capital that can decrease the risk of investment losses and improve the quality of credit. This allows for a lower cost of capital for loans. Guarantees have the advantage over other types of

[3] USD 357 million in June 2024 and USD 50 million in November 2024.

instruments in that they are only used upon an instance of non-payment from a borrower. This enables the mobilisation of more capital per dollar deployed. An example of these guarantees is the Advancing Needed Credit Enhancement (ADVANCE) Trust Fund from the World Bank which provides over USD 1 billion of capital and includes renewable energy generation as one of the areas targeted. The European Union also announced EUR 350 million of loan guarantees for investments in renewables, storage, transport, industry (including steel) and construction materials. Like the political risk insurance, some of the capital is also being deployed through ECAs to enable foreign companies to invest in Ukraine and to ensure the continuation of exports to Ukraine. In an example from Austria, the government expected the effective interest rate for the funds attracted to not exceed 3%. OECD countries also define the minimum interest rates that official financing support for export credits should have (as a function of maturity). In February 2025, these were 2.9%, 5.2% and 5.1% for Euro, US dollar, and British pound denominated bonds.

Capital sources

Identify capital sources that could be used for the different stages considering leverage ratios and leveraging development finance. This stage would aim to match the finance needs by part of the value chain to potential investor types depending on the risk profile. This would ideally be done considering the different maturity levels of the market, but given the high uncertainty associated with the post-war period, the key step would be to determine the sources that could be used for the pilot projects from the next phase. For this, part of the reconstruction funds and development finance targeted to renewables and industry could be expanded to include hydrogen (e.g. direct reduced iron production). While the investment needs for hydrogen are large (see Chapter 2. "The hydrogen opportunity"), investments at Stage 2 are smaller, given the focus on pilot projects, and there is also a large amount of capital targeting reconstruction of the energy sector (see Chapter 1. "Taking stock of the effect of war"). Some assumptions around the way the public capital will be deployed are also needed at this point since different financial instruments have different leverage ratios. A dollar channelled through direct funding instruments (e.g. loan) will mobilise a different amount of private capital to one channelled through risk mitigation instruments (e.g. guarantees) or market incentives (e.g. fixed premium). A loan guarantee could mobilise more than the amount of public funding provided, while capital deployed by multilateral development banks (where around two-thirds of the finance is through loans) mobilises on average less than USD 0.4 for every USD of public funding.

Stage 2 (5 years)

Financial needs

Update finance needs with cost data from pilot projects. This stage should provide some initial data on the real performance of projects. Even though the data are small scale and refer to first-of-a-kind plants, they could serve to calibrate cost estimates and reduce the uncertainty regarding the projects in the next stage. This increases the certainty of the capital needed and allows for better matching with the capital sources and funding programmes.

Financial needs

Split finance needs by project type and risk profile to match with capital sources. The risk allocation in hydrogen projects will be different if it is a stand-alone production project for export, a hub with co-located demand or just the infrastructure. At this stage, the risks associated with each project type need to be identified to understand how those risks are allocated across the different stakeholder types, and to be able to match the finance needs along the value chain to the right stakeholder. For example, debt-based infrastructure funds usually have longer time horizons (up to 30 years) but could require a higher premium. A development finance institution has a higher risk tolerance and also requires a lower premium, but their contribution is usually a much smaller share of the total project cost. A pension fund might be more suitable for refinance during the operational phase once the construction and technology risks have been cleared.

Risk mitigation

Address offtake risk to unlock final investment decisions for the large-scale projects of the next stage. One way to split the hydrogen project risks is by stage (pre- and post-final investment decision [FID]). The most critical pre-FID project-specific risk is the offtake risk, which can be decomposed into certainty (binding character), price (premium over production cost) and volume (share of the production that is covered). Some alternatives to deal with the volume component include (sectoral) quotas such as those of the European Union, public procurement (e.g. for steel, discussed previously in this chapter), a double auction mechanism (which also tackles the price risk), and demand aggregation platforms that bring different users together to avoid projects needing to rely on a single off-taker. The price risk could also be tackled through fixed premiums, Contracts for Difference or Carbon Contracts for Difference (converted to hydrogen prices), which have a common duration of 10-15 years. To enhance certainty, long-term offtake agreements could be used to provide visibility on the revenues over time, which is essential when project finance is used. To date, these contracts have typically been for periods shorter than the lifetime of the project, but as Ukraine reaches this stage, the global hydrogen market might be more developed, with contracts from (European) off-takers that have a longer duration. Once the project takes FID, the offtake risk changes to counterparty risk and it is linked to the creditworthiness of the off-taker. Credit guarantees could be used to decrease this risk (as already done for other parts of the economy), as could credit enhancement mechanisms like credit default swaps or loan loss reserves.

Capital sources

Develop a sustainable finance taxonomy aligned with international standards. A sustainable finance taxonomy is a classification system that identifies the activities, assets and project categories that deliver climate and sustainability objectives towards identified targets. Such a taxonomy could allow Ukraine to tap into a new pool of capital. In 2023, more than USD 1.2 trillion of sustainable debt was issued, with more than 40% of this for energy and utilities. Over three-quarters of sustainable debt issuance is concentrated in developed regions, but there are signs of expansion in emerging markets and developing economies (EMDEs). NEOM, one of the largest projects with an FID in an EMDE, used "green loans" as part of its financing structure. By February 2024, there were 47 taxonomies around the world, so there are plenty of examples that Ukraine could use as reference. Some of the aspects to be covered in the taxonomy design are the strategic goal, the environmental objectives, sectoral coverage, performance criteria, governance and reporting guidelines. Finance taxonomies are closely linked to rules for debt issuance and reporting requirements for financial institutions. The taxonomy should be closely aligned with guidance on transition finance for the private sector, for which there are multiple guidance documents from organisations such as ICMA, CBI, GFANZ, OECD and others. Ukraine already has a starting point: in June 2021, a law establishing green bonds as a new financial instrument was passed, and there is previous analysis on developing a green finance taxonomy for Ukraine.

Stage 3 (10-20 years)

Risk mitigation

Perform an ex-post assessment of the effectiveness of risk mitigation measures. Deployment to full scale will take several years, creating the opportunity to learn from early projects and adapt policies and regulations as needed. In the United Kingdom, for example, the government has launched two rounds of the Hydrogen Production Business Model, a mechanism that provides revenue support by providing subsidies to producers with allocation taking place through a competitive scheme. The government is developing the approach for future allocation rounds based on lessons learnt from the first two rounds to ensure they deliver on the government's priorities. Similarly, in the European Union, the terms and conditions of the second auction of the European Hydrogen Bank were changed with regards to the ceiling price and terms of the completion guarantee, and a specific portion was assigned to a sector (maritime). A similar approach could be followed to design the policy instruments in the last part of Stage 3 when the market starts to mature.

Capital sources

Tap into alternative models of financing to unlock capital for the large-scale projects. Given that the investment needs for hydrogen are relatively large for a single funder, blended finance instruments that pool resources from different stakeholders could be used, making the individual contributions accessible to a broader range of actors. This approach has been used in the Green Hydrogen Facility Fund in Chile, for example.[4] This is a USD 1 billion fund which combines funding from multilateral and national development banks with national funds,[5] and is expected to leverage USD 12.5 billion of private capital. This capital would be enough to finance the full size of the hydrogen valley in Reni (see Chapter 2. "The hydrogen opportunity") of 3 GW of electrolysis. Project finance can also be an alternative to fund hydrogen projects. In Ukraine, the conditions that favour project finance include its potential use for capital-intensive assets in countries with high political risk and weak creditor rights, while not impacting the credit record of the borrowers, since the loans are linked to the cash flows of the project rather than the creditworthiness and balance sheet of the borrowers. At the global level, more than half of the climate finance in 2022 was in the form of project finance. This varies by region, sector and technology. For the electricity sector, project finance can account for about one-third, and for transport, about 45%. Solar PV and wind are increasingly financed on a project basis. For example, project finance is used for over 95% of the solar PV capacity in Germany, and for over 70% of the offshore wind capacity in the European Union. This will only be possible for Ukraine once the market matures towards the end of Stage 3.

Capital sources

Increase reliance on debt rather than equity for large-scale projects. Higher-risk projects are usually financed with more equity than debt given its higher expected returns, which are only possible upon a higher exposure to risk. The debt-to-equity ratio is affected by geography (country and political risks),

[4] Chile has a very different risk profile and renewable track record to Ukraine today, so using blended (and project) finance will depend on the progress made to reduce risk before Stage 3.
[5] USD 400 million from the Inter-American Development Bank, USD 150 million from the World Bank, USD 110 million from the European Investment Bank, USD 110 million from the German Development Bank (KfW) and national funding through CORFO (national development agency).

technology/sector and market maturity. For example, across technologies, low-carbon fuels had a debt share of about 20% between 2018 and 2023, whereas low-carbon power generation had debt shares of 50% for the same period. Similarly, a developed market like Europe had average debt shares of 55% across energy assets, while India had 20%. In terms of maturity, an example is from offshore wind in Denmark, which went from (estimated) debt shares of nearly 25% in 2008 to 70% in 2017 with capacity nearly tripling during this period. Likewise, the (real) debt ratio for solar PV in Germany went from 70% in 2003 to almost 90% in 2017. The average debt ratio for renewable projects is 70-85% for most European countries. What this means for hydrogen projects is that more equity will most likely be used during early stages of deployment, with more debt used as the market matures, decreasing risks and bringing down the expected returns to the typical range of debt. This will most likely happen in the latter part of Stage 3, since initial large-scale first-of-a-kind projects (at that size) might still be perceived as risky.

Capital sources

Transition to self-finance of the hydrogen infrastructure. During the early stages of market development, when the flows through the pipelines are too low, which could lead to high transmission fees, some alternatives to provide cash flows to the hydrogen network operator are subsidies, a tariff deferral system or temporary cross-subsidisation (e.g. from the gas network). At this stage, the hydrogen exports by pipeline should be ramping up, so the tariffs for the network should be cost-reflective and the need for subsidies should be lower. The hydrogen network operator will probably not have a large balance sheet to fund new investments, but this might be less relevant in the case of Ukraine, given the large natural gas infrastructure that could be repurposed (see Chapter 2. "The hydrogen opportunity").

Foster international collaboration, train the workforce and develop the standards

Figure 3.5 Activities across stages for the cross-cutting pillar

Priority: 🔴 High 🟡 Medium 🟢 Low

Sub-category	Stage 1 (2-3 years) Laying the foundations	Stage 2 (5 years) Building the experience	Stage 3 (10-20 years) Scaling up and market growth
International collaboration	🔴 Establish a **network for** domestic **financial institutions** to interact with foreign ones to develop confidence in risk mitigation 🔴 Participate in **platforms** in Europe that are demand-oriented to identify **potential off-takers** 🔴 Promote collaboration between **domestic** hydrogen industry players and **foreign** companies 🟡 Promote collaboration between **transmission network operators**	🔴 Identify **lighthouse projects** that could be funded by foreign and domestic FIs 🔴 **Co-ordinate public support with EU governments** to facilitate the development of hydrogen corridors 🔴 Intensify **collaboration with demand hubs** supplied by hydrogen corridors 🟡 Implement lessons from frontrunners in **large-scale industrial projects** 🟡 Engage with other **emerging economies** to learn from their project execution	🔴 Participate in international initiatives where **knowledge exchange on large-scale projects** takes place 🟢 Consider engagement with **hydrogen importers by ship**

Priority: 🔴 High 🟡 Medium 🟢 Low

Sub-category	Stage 1 (2-3 years) Laying the foundations	Stage 2 (5 years) Building the experience	Stage 3 (10-20 years) Scaling up and market growth
	🟡 Establish partnerships for knowledge exchange on **R&D and technology transfer** 🟢 Participate in **hydrogen-dedicated platforms** to benefit from **learnings** in other countries 🟢 Establish **Bilateral agreements and MoUs** at the government level	🟢 Participate in **dedicated R&D** knowledge exchange **platforms** (e.g. IEA Technology Collaboration Platforms) 🟢 Establish partnerships with countries with high **electrolyser manufacturing capacity** 🟢 Participate in platforms that allow **co-ordinating carbon pricing** increases	
Capacity building	🔴 **Assess skills gap** between the current workforce and skills needed for hydrogen deployment at large scale 🔴 Identify **alternatives to close the skills gap** including retraining programmes, new tertiary education programmes and apprenticeships 🟡 **Train staff across government agencies** to ensure there are enough qualified staff to plan, approve, oversee hydrogen projects 🟡 Assess **gap in numbers of workers** needed for deployment of renewable hydrogen) 🟢 Assess if **dedicated tertiary education programmes** are needed to cover skill gaps 🟢 Establish **student exchange programmes** with other European countries with focus on renewables and hydrogen programmes 🟢 Establish **researcher-exchange programmes** with developed economies	🔴 Promote **joint projects** between domestic players and foreign project developers 🔴 Ensure there are **foreign companies** with hydrogen experience during the **construction phase** of pilot projects 🟡 Leverage **technical assistance** programmes from development institutions 🟡 Establish a **dedicated** team with hydrogen expertise **within the government** 🟢 Establish **dedicated** training and education **hydrogen programmes**	🔴 Establish a mechanism for industry to provide **feedback to educational curricula** 🟡 Promote a mix of foreign and domestic EPC companies
Technical standards	🔴 Identify the **current standards** that would be **applicable to hydrogen** technologies and centralise in a single repository 🟡 Identify the **public body** that would be responsible for **oversight** and enforcement of technical standards 🟡 Evaluate if **international standards** can be directly **adopted**	🔴 Designate a national standardisation body to **participate in CEN/CENELEC** 🔴 Ensure all standards **for repurposing of natural gas infrastructure** are in place 🟡 Build a **public platform** with the status of technical standards development 🟢 Participate in **pre-normative research stages** of technical standards	🟢 **Propose new standards** based on the experience from the first large-scale projects

Learning from experiences in other countries, building a skilled workforce and developing technical standards are essential enabling actions for hydrogen deployment.

Stage 1 (2-3 years)

International collaboration

Promote knowledge exchange between domestic and foreign financial institutions, research centres and companies. Low-emissions hydrogen production and its use in new applications are already taking place around the world. Ukraine could benefit from this experience by establishing partnerships and platforms to exchange knowledge. Engaging a mix of foreign and domestic contractors and project developers in deployment can increase the chances of on-time and on-budget delivery, and allows for domestic contractors to benefit from the experience of foreign companies while building domestic capacity. Arcelor Mittal, for example, is the largest foreign company in Ukraine and is planning to develop multiple H_2-DRI plants across Europe. For renewable hydrogen production, CWP Global acquired a 73 MW onshore wind farm in

Ukraine in 2021, which was supposed to start operations in 2023 (later delayed to 2026). CWP Global has already developed over 6 GW of renewable capacity around the world, has operations in several southeast European countries and has a global portfolio of hydrogen projects that would require over 140 GW of renewable capacity. Knowledge exchange can also benefit financial institutions. While pilot projects could be funded with grants and equity from project developers, commercial banks will have an important role in subsequent stages, so it is important to get them involved early in the process. Exchange with banks and debt funds from other regions at this stage will be essential to develop confidence and knowledge about hydrogen projects. Lastly, local innovation capability could be developed, ready to improve hydrogen technologies and project designs in the last stage. This can be supported by knowledge exchange between research institutions and universities.

International collaboration

Establish bilateral agreements with potential importers and participate in hydrogen-specific platforms. Participating in hydrogen-specific platforms could be useful to build awareness of activities and identify policies, programme and project approaches that have been successfully implemented in other countries. This could inform high-level decision-making, facilitate dialogue in areas that require global co-ordination (e.g. certification), lead to joint analysis and support the development of new analytical tools, among other benefits. The Hydrogen Initiative from the Clean Energy Ministerial, which was launched in 2019, pursues most of these goals. It has 21 members including some of the largest hydrogen producers today and frontrunners in low-emissions hydrogen deployment. Mission Innovation also has a dedicated initiative for hydrogen, with the objective to reach a cost level of USD 2/kg and facilitate the delivery of 100 large-scale hydrogen valleys worldwide by 2030. The initiative has 20 members and is oriented towards research. Participation in the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) would be useful for technical standards. In the area of bilateral foreign relations, Ukraine has received specific analytical support for hydrogen through the H_2-diplo initiative of the German Federal Government, and there is a German-Ukrainian partnership which has been focusing on energy policy, modernising the energy market and addressing bottlenecks for renewables. In 2023, Ukraine also signed an MoU with the European Union on biomethane, hydrogen and other synthetic gases, which includes alignment on definitions and methodologies, harmonisation of regulation, market integration, and cost reduction, among others.

Capacity building

Assess skills gap in the workforce and define a roadmap to close them. Large-scale education and training programmes will be needed to ensure there are enough qualified people for hydrogen development (see Chapter 2. "The hydrogen opportunity"). Mapping the jobs to skills at different parts of the value chain will be needed, followed by an identification of training requirements. Australia provides an example where this mapping has been done in detail. Elsewhere, a skills framework has been proposed for the United Kingdom, and Namibia has a roadmap for implementation. Part of the hydrogen workforce could come from retraining some people working in the renewable sector, but given the large numbers, dedicated tertiary education programmes will be needed. These should begin at this stage so that the workforce is ready when the large-scale projects start to be deployed. For reference, in the academic year 2022/2023, there were about 10 000 engineering graduates in Ukraine at undergraduate level and nearly 3 500 at Master's level. An international exchange programme for students (and researchers) might help to close the gap, with the expectation that some of them will stay (or return). Public workers in the various agencies of the government should also have enough knowledge to design, implement and evaluate the policies. Agencies should be well-staffed in line with the ramp-up and considering adjacent areas such as renewables. In the European Union this has been one of the action areas to accelerate renewable deployment.

Technical standards

Establish the technical standards for the hydrogen value chain and their governance. The first step is to perform a gap assessment to understand what standards are needed by part of the value chain and which are missing. This would be followed by a survey of international standards to determine which can be directly adopted. The remaining gaps would need to be prioritised, specifying a timeline for development under the leadership of working groups. This should be done together with other standard-setting organisations such as the European Committee for Standardization (CEN) and European Electrotechnical Committee for Standardization (CENELEC) and the International Organization for Standardization (ISO) and the International Electrotechnical Commission (IEC) to avoid duplication of efforts and shorten development timelines. Previous exercises that could serve as a reference for Ukraine include those in Australia, Europe, and India. The government agency overseeing the process should also be defined at this stage, along with working groups dedicated to specific topics and an annual work plan setting out activities and milestones.

Stage 2 (5 years)

International collaboration

Co-ordinate public support and finance to facilitate lighthouse projects. A lot of the hydrogen ramp-up depends on how exports develop, and these in turn depend on the evolution of the demand (mostly in northwest Europe). This provides the opportunity to use domestic and European finance to fund some of the projects that are export-oriented, pooling resources with different risk tolerance and time horizons. Co-ordinating public support is also essential to ensure that ramp-up of deployment happens at the same time as ramp-up of demand. A close monitoring of market developments, as well as developments in the European import corridors, will be needed to inform policy implementation.

Capacity building

Promote joint projects between foreign and domestic actors and establish specific hydrogen teams within government agencies. While activities in Stage 1 focus on exchanging knowledge to develop domestic capabilities, the focus of this stage is execution. The pilot projects will have been co-developed with foreign companies (which is especially important during the engineering and construction phases). Dedicated teams within the government will be trained and ready to roll out the policies needed for the large-scale deployment of the next stage. These are also benefitting from technical assistance programmes from development institutions and from international collaboration. The (re)training programmes identified in the previous stage are already in place and some initial hydrogen-specific courses and degrees are starting to emerge towards the end of the stage. Examples from Europe, France, Germany, and the United Kingdom might be useful for envisioning how these programmes could look.

Technical standards

Develop a public repository of hydrogen standards and standards under development. A single repository could be useful for project developers, like the repositories available in the European Union and the United States. Ideally, this would also be linked to an overview of the applicable regulations and incentives. Standards can take 4-8 years to go from pre-normative (research) activities to being in place, so keeping a public record of the development status will be important for project planning. The next stage should see the use of transmission pipelines for exporting hydrogen, so this stage should ensure that the corresponding standards to clean, convert, inspect and maintain the repurposed natural gas pipelines (if applicable) are in place. A definition of the operating conditions, frequency and type of inspection needed will be necessary to ensure the mechanical integrity of the pipeline given the potential occurrence of hydrogen embrittlement.

Stage 3 (10-20 years)

International collaboration

Exchange knowledge on experience from large-scale projects and establish partnerships for exports beyond the European Union. To maximise cost reduction, learning should not be limited to domestic experience, but should also extend to similar projects being undertaken elsewhere. Any efforts around standardisation and replication, in either the technology, policy or project execution areas, would be useful to accelerate deployment. International platforms that exchange knowledge on these large-scale projects would be useful for this purpose. At this stage, projects in Ukraine would be achieving economies of scale and, as costs go down, new avenues of export might open. This will depend on how global trade, markets and the technology costs for shipping and (re)conversion have evolved, so a reassessment would be useful at this point.

Capacity building

Establish a process for industry to provide feedback on the educational curricula. At this stage, the first batches of students from the new hydrogen-oriented programmes would be entering the workforce and the first large-scale projects would be under construction, providing an opportunity for learning about the skills and professions needed. For example, the focus might have shifted from ammonia production to steel, which requires different specialist knowledge. The government could consider putting in place a way for industry to provide input on the curricula and reap the double benefit of satisfying the market needs while increasing the chances of students finding a job upon graduation.

Technical standards

Review new standards based on experience and participate in pre-normative research activities. By this stage, Ukraine should have developed some domestic research capabilities which would enable participation in research activities that could inform new technical standards. Based on the experience from the pilots and first large-scale projects, Ukraine could propose changes to existing standards. This could be done through the networks and collaboration established in the first stage. By now, the technical standards would be clear for project developers and already embedded in the design, construction and operation of the plants.

Policy recommendations for the coming 2-3 years

Prioritise deployment of renewables to boost energy security and create an enabling environment for future hydrogen development. Ukraine currently lacks adequate power generation capacity and restoring energy security must be a priority. Any activity focused on accelerating deployment of renewables will have positive spillover effects for hydrogen, by building experience across the workforce and companies and helping to build confidence among potential investors. This will also indirectly reduce the cost of capital by reducing the uncertainties related with renewable electricity generation. Similarly, any efforts related to permitting and administrative processes for renewables can also support the creation of standardised processes that could be used as a starting point for the corresponding processes for hydrogen projects. An initial focus on renewables can support progressive steps towards hydrogen deployment that could ultimately increase the chances of success and reduce the likelihood of delays, since fewer new elements are introduced at a time. If renewables deployment precedes hydrogen deployment, it can reduce uncertainties around the cost estimates for hydrogen projects, since data would be based on real projects. It could also allow for a process of standardisation and economies of scale that unlock lower electricity costs, which are the dominant driver for hydrogen production costs.

Undertake the preparatory analyses that will form the basis for later deployment. Such studies require relatively little investment when compared to large-scale projects, but they are essential to inform the work done in later years. They can support progress without requiring large commitments and provide a window onto market development. Preparatory studies can reduce uncertainties by including a material assessment of the gas transmission network, improving project cost estimates and providing visibility on the policy instruments that could be used to promote hydrogen deployment. Analysis could include, for example, feasibility studies for lighthouse projects, hubs or fully integrated projects, mapping and addressing any skills gaps, mapping current legislation that is applicable to hydrogen, and defining principles and a methodology for hydrogen certification. Techno-economic analysis comparing production in Ukraine with other countries (from the importer's perspective) will also be useful, as will setting up platforms for collaboration. Preparatory studies to inform the next steps could include identifying the risks that could affect different project types and the corresponding mitigation measures, mapping the international funding programmes that could be used to finance hydrogen deployment and assessing the interest from foreign companies to develop hydrogen projects in Ukraine.

Mitigate financial risks introduced by the war. Hydrogen production from electrolysis is highly capital-intensive. Any additional premium on the cost of capital makes a big difference in the levelised cost. A large share of the current premium comes from the additional risk and uncertainty created by the ongoing war. There are already various programmes and organisations helping to address these risks through political risk insurance. Action is now needed to deploy this tool effectively across various settings and types of projects in order to provide confidence to the financial sector and enable the transition from development to commercial finance.

Build the workforce that will be needed to scale up hydrogen deployment. Massive population displacement and relatively low renewables deployment have created a shortage of experienced staff. Immediate action is needed to ensure there are enough qualified staff across the government to design, implement and evaluate the policies; in the private sector, to execute, construct and operate projects; and in research organisations. Key priorities include collaboration and exchange programmes across different stakeholder groups, retraining and reskilling programmes, and a revamping of the education system to build the workforce needed for large-scale deployment and ensuring gender balance.

Complete integration with the EU regulatory framework as part of the accession process. Aligning as closely as possible with the EU regulations could be beneficial for hydrogen deployment for three reasons. First, the European Union already has a comprehensive framework covering demand-side incentives (through the Renewable Energy Directive, ReFuelEU Aviation and FuelEU Maritime), infrastructure regulation, supply-side incentives and a stronger carbon price signal. Second, becoming a member of the European Union would allow Ukraine to tap into additional funds and potentially benefit from programmes that target equity between member states, such as the Cohesion Policy, which has this objective at its core, and has a total budget of EUR 392 billion for the 2021-2027 period. This is nearly one-third of the original multi-annual financial framework. Third, domestic hydrogen deployment is closely tied to exports. The European Union is the region with the largest potential demand that can be connected by pipeline. Alignment in regulation would facilitate exports, for example through a compatible certification scheme, or common regulations for transmission pipelines.

Modernise domestic regulation and infrastructure. Renewable hydrogen cannot be deployed without a well-functioning and economically efficient electricity market. First, this will require reform of the electricity market, including removing market distortions such as price caps, considering social equity, ensuring tariffs are cost-reflective, establishing new ancillary markets that reward flexibility, revising the feed-in tariff scheme and resolving debt issues for state-owned enterprises. Second, power infrastructure also requires modernisation, including accelerating the roll-out of batteries and putting in place an enabling regulatory framework that supports the growth of distributed electricity resources and expansion of the electricity grid. Batteries and grid expansion could, over time, reduce price volatility, and do so in different regions in the case of grid-connected electrolysers. Incentives provided for electricity generation should be pragmatic, considering the current capacity shortage and long-term decarbonisation needs. Both the average grid emissions intensity over time and the attractiveness of the market for developing a domestic renewable industry can have spillover effects for hydrogen. Finally, improving the governance standards of the energy sector and state-owned enterprises, in line with international standards, could decrease the perceived risks of renewables – and, therefore, of renewable hydrogen.

Follow a progressive approach to deployment and build the track record needed to develop investors' confidence. One of the main challenges for hydrogen projects is the high perceived risks driven by the macroeconomic and geopolitical situation. Following a gradual approach to deployment, both for the supply chain and in terms of project size, would be less risky than introducing multiple simultaneous changes, and limit the investment needed during the early stages. For example, starting with renewables projects carries lower risk than aiming to demonstrate the production of near-zero emissions steel directly. Small projects can also be more attractive to investors, who may get involved with the aim of becoming frontrunners in this market. To attract foreign investors, it is fundamental to build a track record of projects completed on time and on budget, and this will be much easier with a progressive approach.

Annex

Table A.1 Estimates of renewable energy potentials in Ukraine

Technology	Potential	Notes	Source
Solar PV	83 GW (99 TWh/yr)	-	NAS Ukraine 2020
	39 GW	Technical potential excluding agricultural land, protected areas, proximity to grid, population density	Doronina et al. 2024
	57 GW (74.1 TWh/yr)	Technical potential	Energy Community 2024
	11 301 GW (11 866 TWh/yr)	Theoretical potential excluding protected areas, slope >30%, forests, wetlands, snow, water	Greenpeace 2024
	5 084 GW (5 339 TWh/yr)	As per line above including a criterion of grid proximity of 10 km	Greenpeace 2024
	726 TWh/yr	Technical potential	HYPAT 2023
	4 GW	"Reasonable" potential	IRENA 2015
	71 GW (88 TWh/yr)	Technical potential	IRENA 2017
	3 516 GW (4 140 TWh/yr)	Technical potential (85% of this potential has a capacity factor below 0.14)	ESMAP (2020)
	176 TWh/yr	-	Shell (n.d)
	147 GW (234 TWh/yr)	Capacity factor >16%, 10% of full technical potential	IEA
	2 824 GW	Technical potential with 97 MW/km^2	Stanford 2021
	333 GW (399 TWh/yr)	Capacity factor higher than 0.13 and potential within 100 km of settlement	Pietzcker 2014
Onshore wind	438 GW (1 189 TWh/yr)	-	NAS Ukraine 2020
	180 GW	Technical potential excluding agricultural land, protected areas, proximity to grid, population density	Doronina et al. 2024
	290 GW (1 102 TWh/yr)	Technical potential	Energy Community 2024
	2 146 GW (6 546 TWh/yr)	Theoretical potential excluding protected areas, slope >30%, forests, wetlands, snow, water	Greenpeace 2024
	950 GW (2 897 TWh/yr)	As per line above including a criterion of grid proximity of 10 km	Greenpeace 2024
	16-24 GW	Economic potential	IRENA 2015
	139 TWh/yr	-	Shell (n.d)
	181 GW (460 TWh/yr)	Capacity factor > 20%, 10% of full technical potential	IEA

Technology	Potential	Notes	Source
	274 GW	Less than 5% of this potential is estimated to have a capacity factor higher than 20%	Stanford 2021
	1 431 GW (2 781 TWh/yr)	Capacity factor higher than 20%	Bosch 2017
	688 GW (2 174 TWh/yr)	Technical potential without land constraints	Kudria 2021
	320 GW (858 TWh/yr)	Technical potential	IRENA 2017
	976 TWh/yr	Technical potential	HYPAT 2023

Note: NAS Ukraine = National Academy of Sciences of Ukraine.

The potential used in this report is a constrained technical potential. The theoretical potential considers all possible land without restrictions. The technical potential considers land exclusion zones to account for social and ecological constraints like industrial areas or wetlands (see Table A.2). We further assume that only 10% of the technical potential can be used for renewables, so the numbers shown in the main text would need to be multiplied by ten to obtain the full potential. The technical potential could be further constrained by applying an economic threshold, since a share of the resources might be accessible but too expensive to use. We do not make any assumptions on economic thresholds. The analysis has a resolution of 0.25°, which is equivalent to about 22.5 km. By constraining the potential to 10%, the best 10% of each ~500 km^2 cell is used.

Table A.2 Land exclusion zones for renewable hydrogen production potential

Layer	Onshore wind	Offshore wind	Solar PV	Comment
High-density settlements	1 000 m	1 000 m	100 m	
Isolated settlements	3 TH	3 TH	100 m	TH = Tip height
Air traffic radars	7 500 m	6 000 m	100 m	
Air traffic common equipment	100 m	100 m	100 m	
Airfields	1 500 m	3 600 m	0 m	Average values
Medium and large airports	6 000 m	7 200 m	0 m	Average values
Railways	1.2 RD	-	10 m	
Cable cars	3 RD	3 RD	5 m	RD = Rotor diameter
Power lines	1 PS	500 m	5 m	PS is a relative metric that translates roughly to 2 RD
Submarine cables	-	6 RD	30 m	
Pipelines	400 m	500 m	8 m	
Oil and gas rigs	0	6 RD	30 m	

Layer	Onshore wind	Offshore wind	Solar PV	Comment
Cropland	-	-	0 m	
Pastures	-	-	0 m	
Glaciers	-	-	1 000 m	
National	0.5 AS	0.5 AS	0 m	AS = Intra-wind farm distance
Military	0 m	-	0 m	
Protected areas (cat. I-IV)	300 m	-	100 m	
All protected areas	-	500 m	0 m	
Bird areas	2 170 m	2 170 m	0 m	
Intact forest	0 m	-	0 m	
Wetlands	2 170 m	5 000 m	100 m	
Coral reefs	-	1 000 m	-	
Mangroves	-	1 000 m	0 m	
World Heritage sites	8 000 m	16 000 m	1 000 m	
Salt flats	0 m	-	-	
Dunes	-	-	900 m	
Sea ice	-	0 m	-	
Iceberg	-	0 m	-	
Water depth	-	0 m	-	
Anchorages	-	3 704 m	-	
Industrial and commercial zones	2 TH	-	0 m	TH = Tip height
Mining sites	100 m	-	100 m	
Coast	100 m	2 000 m	100 m	
Coast (inhabited)	-	2 000 m	-	
Flood areas	0 m	-	0 m	
Lakes	100 m	-	100 m	
Creeks	0 m	-	0 m	
Rivers	100 m	-	100 m	
Water surface	100 m	-	100 m	
Maximum slope	17°	-	4°	
Historical sites	1 000 m	-	0 m	
Recreational areas	100 m	-	0 m	
Camping	3 TH	-	0 m	TH = Tip height

Layer	Onshore wind	Offshore wind	Solar PV	Comment
Shipwreck	-	100 m	-	
Shipping lanes	-	0 m	-	
Weather radars	7 500 m	7 500 m	100 m	

Notes: The layers describe the minimum distance wind turbines and solar PV installations should have from elements of the built and natural environment. 0 m means that renewable assets can be built immediately next to the respective areas.
Source: Jülich Systems Analysis at Forschungszentrum Jülich.

EU4Energy is a collaboration between the IEA, the European Union, Focus Countries and other implementing parties, designed to support the aspirations of Focus Countries to implement sustainable energy policies and foster co-operative energy sector development at the regional level.

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Typeset in France by IEA - March 2025
Cover design: IEA
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Co-funded by the European Union