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Germany's gas dependence: An energy security risk

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Key findings

Germany's residential heat pump installations from 2022 to 2025 saved the country €1.3 billion on liquefied natural gas imports in the three years between 2023 and 2025.

Germany should continue replacing gas demand with renewables, heat pumps and energy efficiency programmes. This would lower the country's exposure to volatile gas prices and strengthen its energy security.

Germany is betting on hydrogen power to support renewables. But high costs, infrastructure gaps and project execution risks suggest hydrogen power will play a smaller role than government forecasts.

High costs and technical risks mean carbon capture is not a near-term solution for Germany's planned 10 gigawatts of new gas power plants. Utilities relying on carbon capture face uncertainty over emissions cuts.

Executive summary

Germany can lower its exposure to volatile gas prices and geopolitical conflicts by scaling up renewable energy and clean heating systems. These, alongside cross-border grid connections and energy efficiency programmes, would displace gas generation and reduce the need for expensive hydrogen infrastructure. IEEFA estimates that this strategy would allow Germany to source just 5% of its electricity from natural gas and hydrogen combined by 2045.

The country has already made significant progress. Its gas consumption peaked in 2021. Electrification and the installation of heat pumps contributed to a 23% decline in household gas use between 2021 and 2024. IEEFA estimates that the almost 1.1 million residential heat pumps that Germany installed from 2022 to 2025 saved the country €1.3 billion on liquefied natural gas (LNG) imports between 2023 and 2025.

Germany's LNG terminal utilisation rate in 2025 was 36.3%, far below the EU average. This indicates that decisions to build LNG terminals failed to fully consider future gas demand. Nonetheless, the country still plans to almost triple its LNG import capacity by the end of 2028.

In the power sector, Germany's government prioritises natural gas and hydrogen to support a system dominated by solar and wind. The country plans to build 10 gigawatts of hydrogen-ready gas power stations. But hydrogen power plants will likely play a smaller role than government plans because of their high expense and low efficiency.

Germany may aim to decarbonise some of its gas power stations with carbon capture and storage (CCS). But CCS has never been used at scale on existing gas plants because of technical and economic challenges. CCS projects globally have underperformed, costs are prohibitively high, and Germany does not have a carbon dioxide pipeline network.

CCS is therefore not a near-term solution for Germany's planned 10-gigawatt gas buildout, in IEEFA's view. If the country does attempt to decarbonise these assets with CCS, subsidies could cost hundreds of billions of euros. The gamble is that reliance on the technology could delay more viable alternatives and expose Germany to project failures. These same issues apply if Germany uses blue hydrogen (produced from natural gas with carbon capture) as a fuel in power plants.

German utilities planning to rely on CCS may also face uncertainty in reducing emissions. Despite aiming to decarbonise gas power plants, some utilities have recently signed contracts to import LNG for up to 20 years. These contractual obligations expose the companies to the risk of long-term underutilised gas power plants, potentially locking them into uneconomic supply commitments.

German utilities should carefully weigh the transition risks before signing any more long-term gas import contracts. This would help them avoid additional financial impacts related to the underutilisation of gas plants and align them more closely with the country's climate and energy security goals.

Given these findings, IEEFA recommends that Germany do the following:

- Continue replacing gas demand with renewables, electrification of heating and energy efficiency programmes
- Significantly scale up cross-border grid connections and demand-side management, which would help minimise gas and hydrogen generation
- Cancel plans to build new LNG import terminals, given that it has already passed peak gas consumption
- Carefully monitor gas infrastructure investments to prevent unnecessary increases in consumer gas prices
- Not rely on CCS to decarbonise gas power plants

These measures would provide Germany with a more sustainable and cost-effective path to energy security.

This report is the first in a two-part series on Germany’s energy transition. The second report details the costs to Germany of relying on unrealistic hydrogen demand forecasts.

Germany’s gas dependence weakens its energy security

Key findings:

- Germany's dependence on US liquefied natural gas (LNG) has deepened in recent years, with about 92% of its LNG imports sourced from the US in 2025.
- Gas demand uncertainty may disrupt Germany’s plans to almost triple its LNG import capacity by the end of 2028.
- Germany’s gas consumption peaked in 2021. Household gas consumption fell by 23% between 2021 and 2024, thanks in part to the installation of heat humps, which helped reduce spending on LNG imports.
- Germany can boost its energy security and protect consumers from volatile gas prices by further reducing gas consumption.

Geopolitical issues, global conflicts and price volatility, among other factors, have constantly threatened Germany’s energy security in recent years. The more the country depends on imports of pipeline gas and liquefied natural gas (LNG), the more these events affect its energy market. However, Germany can reduce this dependence by further curbing gas consumption, installing more renewables and increasing energy efficiency measures.

In 2010, Russia was the EU's largest gas supplier, accounting for 34% of the bloc's gas imports (counting both pipeline gas and LNG imports).[1] That dependency grew further as production from EU gas fields declined. Europe's connection with Russia's gas network expanded over the years through pipeline routes to Western Europe and Balkan countries. By 2020, Russia supplied an estimated 48% of total EU gas imports.

In 2021, Russia exported about 150 billion cubic metres (bcm) of gas to European markets via four major pipeline routes: Ukraine, Poland (Yamal-Europe), the Baltic Sea (Nord Stream), and the Black Sea and Turkey (TurkStream). Germany accounted for around 55% of those imports.

Figure 1: Major gas pipelines linking Russia and Europe

Source: The Conversation.

Russia supplied about 52% of Germany's gas imports in 2021.[2] This figure declined to 22% in 2022, following Russia's full-scale invasion of Ukraine earlier that year. By the end of September 2022, Russian pipeline gas stopped flowing to Germany.

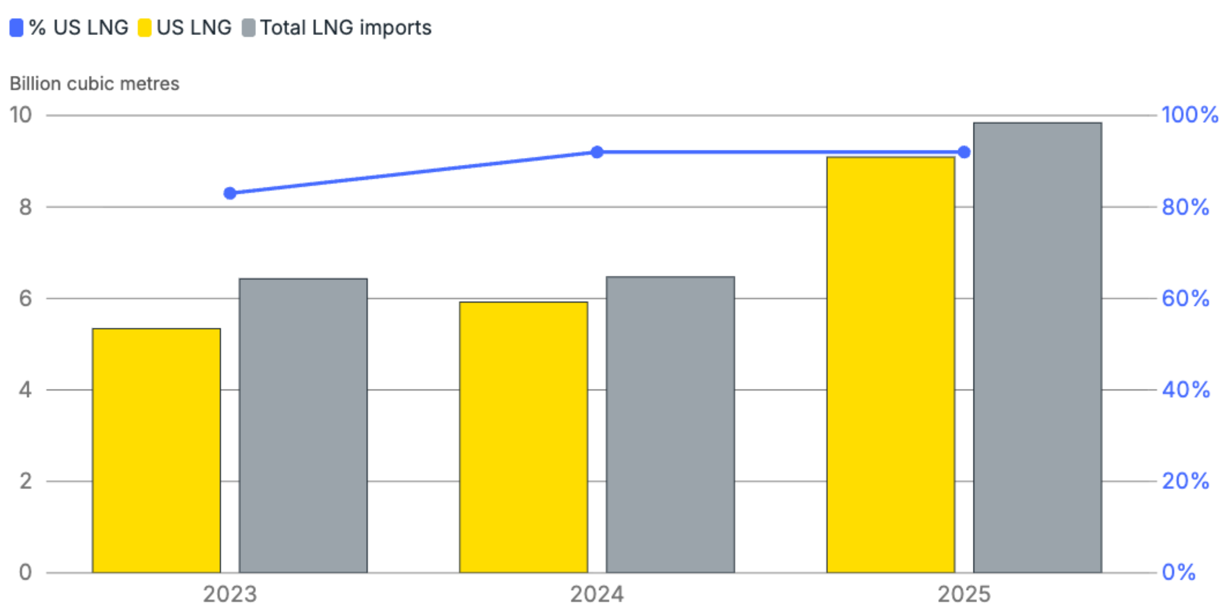
[1] IEEFA. EU Gas: Diversity of Supply or Diversity of Routes? February 2022.
[2] German Federal Network Agency. Bundesnetzagentur publishes gas supply figures for 2022. 6 January 2023.

As Germany pivoted to LNG, it opened its first floating storage and regasification unit (FSRU) for receiving the fuel in November 2022. Cargoes began arriving a month later. LNG represented 7% of Germany's total gas imports in 2023, rising to 10.3% in 2025.[3]

Since Germany began importing LNG, the US has been the main supplier. Germany's dependency on US LNG continues to deepen, as imports from the country rose by 51% in 2025. Germany sourced around 92% of its LNG imports from the US in 2025.

Germany's energy security was at risk in 2022 as more than half of its gas imports were from one source, Russia. Four years later, the country might be facing a potentially high-risk new geopolitical dependency on US gas.

Figure 2: Germany's LNG imports from 2023 to 2025



Source: Kpler.

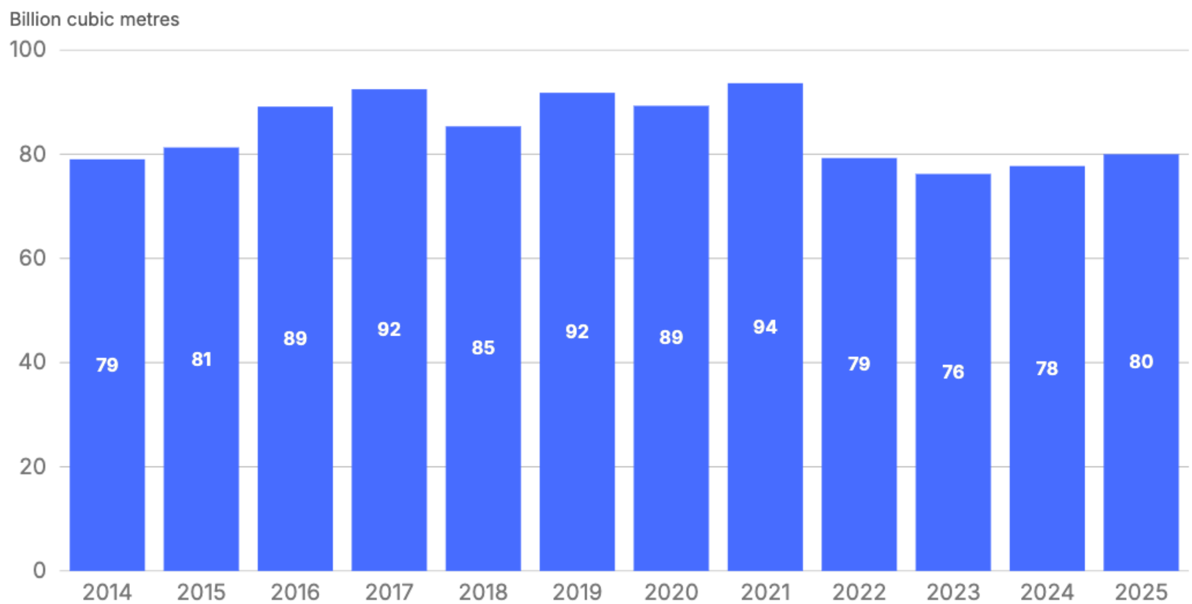
Norway is now Germany's main gas pipeline supplier, followed by the Netherlands and Belgium. Germany also transits gas to neighbouring countries, mainly Austria, Czechia and Switzerland.

[3] German Federal Network Agency. Bundesnetzagentur publishes gas supply figures for 2025. 12 January 2026.

Electrification of heating key to decline in household gas consumption

Germany's gas consumption peaked in 2021, dropped by 15% in 2022 and remained relatively flat in 2023, 2024 and 2025.

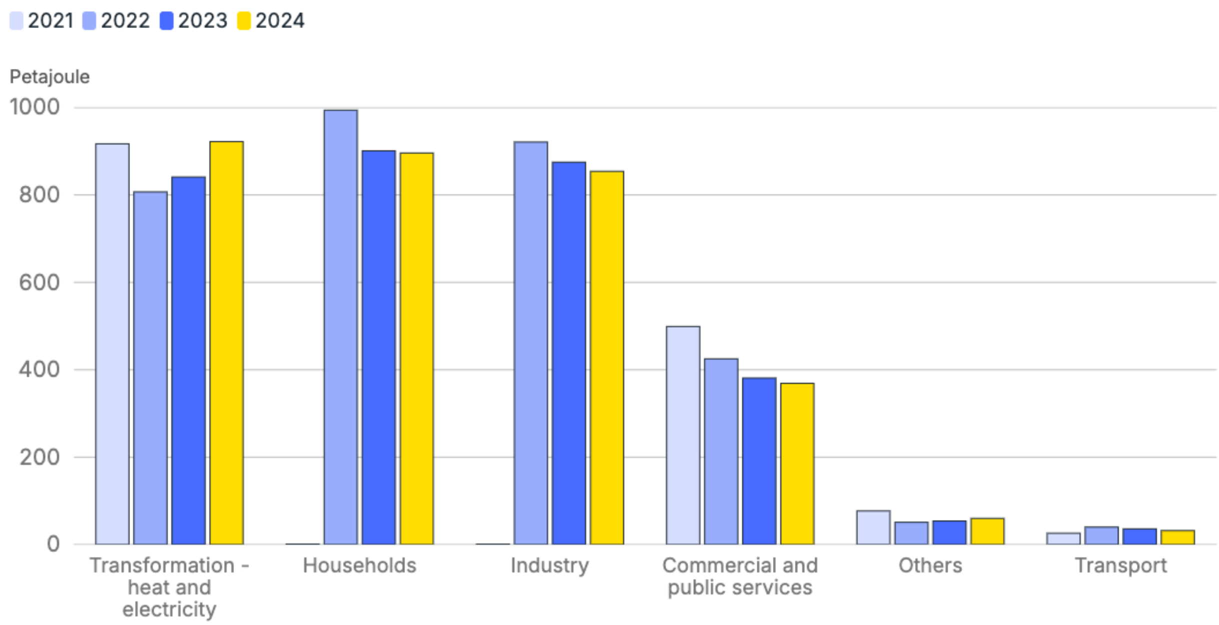
Figure 3: Germany's gas consumption



Source: Eurostat.

Eurostat provides an in-depth look at gas consumption by sector, with data currently available through 2024. According to this data, the largest categories of German gas consumption in 2024 were: gas used for utility electricity and heat generation, at 29.4%; household consumption, at 28.6%; the industry sector, at 27.3%; and commercial and public services, at 11.8%.

Figure 4: Germany's gas consumption by sector



Source: Eurostat.

IEEFA analysed the changes in demand within each of these categories between 2021 and 2024. In that period, gas used for utility electricity and heat generation increased by 1%, household use decreased by 23%, industry use decreased by 21%, and commercial and public services use decreased by 26%. This decline in household gas consumption was in part due to the electrification of heating.

Heat pumps and other clean energy alternatives for heating, such as solar water and space heating, have been displacing gas boilers in German homes. The installation of heat pumps and solar heating was an important factor in the reduction of gas consumption by households in Germany between 2021 and 2024. Other factors like weather and demand destruction caused by high gas prices also contributed to this decline.

Germany enacted a heating law in 2023 that aimed to phase out fossil fuel heating systems.[4] Germany's heat pump sales reached 236,000 units in 2022. After a record year in 2023 of 356,000 units, heat pump sales fell to 193,000 in 2024.[5,6] In 2025, heat pump sales increased again, reaching around 299,000 units sold, topping gas boilers in the country for the first time.[7]

Germany's Federal Funding for Energy-Efficient Buildings programme has provided financial support for efficiency and renewable heating in the building sector. From January 2021 to September 2024,

[4] Clean Energy Wire. Q&A – Germany agrees phaseout of fossil fuel heating systems. 11 September 2023.
[5] Bundesverband Wärmepumpe. Über 50 Prozent im Plus: Wärmepumpen-Absatz steigt 2025 deutlich. 27 January 2025.
[6] European Heat Pump Association. Pump it down: Why heat pump sales dropped in 2024 – a country-by-country breakdown.
[7] POLITICO Pro. Heat pump sales top gas boilers in Germany for the first time. 28 July 2025.

the scheme supported the installation of 303,242 heat pumps, 145,327 biomass heating systems and 905,456 square metres of solar thermal systems.[8] The cost of the programme for this period was €10 billion.

IEEFA examined how the decline in household gas demand in recent years helped reduce the need for LNG imports to Germany. Based on analysis of gas market data, IEEFA assumed that any marginal increase in imports would have been from LNG, rather than from pipeline imports from Norway or other parts of Europe.

Germany installed almost 1.1 million residential heat pumps from 2022 to 2025, which reduced cumulative gas demand by around 40 terawatt-hours in that period.[9] IEEFA concludes that if this number of heat pumps had not been installed, Germany would have had to increase its LNG imports by around 16% in the last three years and would have had to pay an additional €1.3 billion total for importing LNG.[10,11] US LNG accounted for 82% of Germany’s LNG imports in 2023, 90% in 2024 and 92% in 2025. Thus, around €1.2 billion of the €1.3 billion would have been spent on US LNG.

It is important to note that these savings are ongoing, and will replicate in subsequent years, because replacing gas demand with clean energy infrastructure (like heat pumps or solar thermal) generates compounded savings over the entire lifespan of the equipment.

Gas network overview

Germany’s gas transmission network is approximately 40,000km long.[12] It is divided into a high-calorific gas (H-gas) and a low-calorific gas (L-gas) transport network. Germany has 16 gas transmission system operators (TSOs),[13] more than other European countries due to private companies participating in the market. These operators manage cross-regional gas transport and gas transit to neighbouring countries. Germany also has 700 regional gas distribution network operators.[14]

The country’s gas market is interconnected with Austria, Belgium, Czechia, Denmark, France, Luxembourg, the Netherlands and Poland by land and with Norway through the North Sea via multiple pipelines.[15]

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[8] German Federal Office of Economics and Export Control. 10 Milliarden Euro für die Gebäudesanierung durch die Bundesförderung für effiziente Gebäude (BEG): BAFA zieht positive Bilanz. 20 September 2024.
[9] Calculation based on Eurostat database of disaggregated final energy consumption in households.
[10] IEEFA did not consider 2022 as Germany’s first LNG import terminal did not start operating until the end of 2022.
[11] This calculation is based on the estimated average price that EU countries paid for LNG: €43.6 per megawatt-hour in 2023, €31.0 per megawatt-hour in 2024 and €35.7 per megawatt-hour in 2025. The source is IEEFA’s European LNG Tracker.
[12] FNB Gas. The German transmission system.
[13] German Federal Ministry for Economic Affairs and Energy. Natural gas supply in Germany.
[14] Gasunie. Infrastructure in Germany.
[15] European Network of Transmission System Operators for Gas. System Capacity Map 2025.

A group of TSOs own Trading Hub Europe, Germany's gas market coordinator. It is a major gas trading point due to its central location in Europe and high volume.

Germany's Federal Network Agency sets German gas TSOs' regulated revenues through an incentive regulation system.[16,17] This system sets a revenue cap for each TSO based on its necessary operating costs, efficiency and an allowed rate of return, aiming to ensure TSOs remain efficient and do not make monopoly profits. The revenue cap is determined for each five-year regulatory period and is based on a cost examination that includes efficiency benchmarking.

Gas network investments

In 2015, Germany's Federal Network Agency listed 84 measures to expand the country's gas infrastructure as part of the Gas Network Development Plan. The agency said the investment volume for these measures would increase to a total of €3.3 billion by 2025.[18]

Germany has invested in the gas network to enable bidirectional flows in some pipelines and diversify gas supplies. In 2018, Belgian TSO Fluxys completed a project enabling bidirectional gas flows at the TENP pipeline, which links Germany with Switzerland, Belgium and the Netherlands. The investment connected Germany with Belgium's Zeebrugge and France's Dunkerque LNG terminals.[19] In 2022, a technical upgrade at the Obergailbach point enabled gas to flow from France to Germany, supplementing the existing one-way flow from Germany to France.[20]

Other pipelines with reverse flow capacity are Transitgas, which runs from Italy through Switzerland to Germany, and the Penta-West pipeline in Austria, which supplies gas to Germany and France, and enables flows from west to east.

Germany is currently focusing on building a national hydrogen core network by converting natural gas pipelines and constructing new ones to help meet its decarbonisation goals. But supply and demand for hydrogen are still uncertain.

Natural gas prices in Germany are not regulated but are determined according to supply and demand.[21] Since these prices cover all costs associated with the expansion and maintenance of the natural gas grid, the Federal Network Agency should carefully monitor gas infrastructure investments to prevent unnecessary increases in consumer gas prices.

[16] German Federal Network Agency. Revenue Cap Decisions. 31 August 2021.
[17] German Federal Network Agency. Incentive regulation of gas and electricity network operators.
[18] German Federal Ministry for Economic Affairs and Energy. Natural gas supply in Germany.
[19] Fluxys. TENP Pipeline Info.
[20] NaTran. GRTgaz announces delivery of the first physical flows from France to Germany. 13 October 2022.
[21] Ibid.

Accelerated LNG terminal buildout

After Russia's full-scale invasion of Ukraine in February 2022, Germany rapidly decided to install several offshore and onshore LNG terminals and start importing LNG to replace the loss of Russian pipeline gas.

Since the end of 2022, Germany has installed five FSRUs, adding a total of 19.7bcm of LNG terminal capacity. IEEFA forecasts that this installed capacity will almost triple by the end of 2028, to 56.1bcm. But gas demand uncertainty may disrupt these plans.

State-owned company Deutsche Energy Terminal (DET) operates the Brunsbüttel, Wilhelmshaven 1 and Wilhelmshaven 2 LNG terminals. DET planned for the Energos Force FSRU to start operations in 2024 at the Stade terminal. However, following delays to the facility's commissioning, the FSRU was sublet to Jordan in 2025.

German private terminal operator Deutsche ReGas operates the FSRU Neptune at the Mukran terminal. Deutsche ReGas also operated the Energos Power FSRU at Mukran from 2024. But it ended a contract with Germany's government for the vessel in February 2025. The FSRU has since moved to Egypt.[22]

Table 1: Germany's LNG terminal buildout (billion cubic metres)

LNG terminals	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Brunsbüttel 1 (Hoegh Gannet FSRU)		5.0			-5.0					0.0
Brunsbüttel (onshore)					10.0					10.0
Ostsee/Lubmin (Neptune FSRU)		5.0	-5.0							0.0
Ostsee/Mukran 2 (Neptune FSRU)			6.5							6.5
Ostsee/Mukran 1 (Energos Power FSRU)			6.5	-6.5						0.0
Stade 1 (Energos Force FSRU)										0.0
Stade 2 (onshore)						13.3				13.3
Wilhelmshaven 1 (Hoegh Esperanza FSRU)	6.7									6.7
Wilhelmshaven 2 (Excelerate Excelsior FSRU)				1.5	2.0	1.1				4.6
Wilhelmshaven 3 (onshore)							15.0			15.0
Total installed per year (bcm)	6.7	10.0	8.0	-5.0	7.0	14.4	15.0	0.0	0.0	56.1
Total buildout (bcm)	6.7	16.7	24.7	19.7	26.7	41.1	56.1	56.1	56.1	56.1

Source: IEEFA's European LNG Tracker.

[22] Deutsche ReGas. Deutsche ReGas terminates charter contract with the Federal Ministry for Economic Affairs for the FSRU "Energos Power". 10 February 2025.

Rising LNG terminal costs

In April 2022, the German government expressed plans to spend as much as €3 billion on LNG terminals over the following decade.[23] By the end of 2022, the costs of those plans had more than doubled.[24]

Cost estimates continued rising. By March 2023, Germany's parliament had allocated €9.8 billion to support the country's LNG infrastructure expansion between 2022 and 2038. The government said at the time that there would be additional costs on top of that amount.

The land-based Stade LNG terminal is expected to cost around €1 billion alone. [25] It is planned for commissioning in 2027.

In July 2023, the European Commission approved a €40 million support measure for the construction and operation of Germany's land-based 10bcm Brunsbüttel LNG terminal.[26]

In December 2024, the European Commission approved a €4.06 billion grant to support DET operate four FSRUs in Germany. The measure covers the losses incurred by DET for operating the FSRUs until the end of their charter period. The Commission said the grant could rise to €4.96 billion if losses are higher than expected.[27]

Deutsche ReGas cited DET's "ruinous pricing policy" when announcing its decision in February 2025 to end its charter contract for the Energos Power FSRU. Deutsche ReGas said DET's capacities were marketed at "significantly" below the cost-covering fees approved by Germany's Federal Network Agency.[28]

LNG contracting risks

Germany might have overbuilt its LNG regasification capacity as LNG imports have increased at a lower rate than initially forecasted. Germany's LNG terminal utilisation rate in 2025 was 36.3%, below the EU average of 50.8%. Some of the country's new terminals have been cancelled or delayed.

[23] DW. Germany earmarks €3 billion for floating LNG terminals. 14 April 2022.
[24] Anadolu Agency. Germany's LNG terminals to cost more than double: Report. 22 November 2022.
[25] Hanseatic Energy Hub. Green light given for Germany's first land-based terminal for liquefied gases in Stade.
[26] European Commission. State aid: Commission approves €40 million German support for on-shore LNG terminal in Brunsbüttel. 27 July 2023.
[27] European Commission. Commission approves €4.06 billion German State aid measure to support the operation of four Floating LNG Terminals. 20 December 2024.
[28] Deutsche ReGas. Deutsche ReGas terminates charter contract with the Federal Ministry for Economic Affairs for the FSRU "Energos Power". 10 February 2025.

Nonetheless, the country still plans for LNG to play a key role in electricity and heat generation. German power utilities such as EnBW, RWE and Uniper continue signing long-term contracts and heads of agreements for LNG.

As Germany’s 2025 gas demand was nearly 13.5% below its average demand for 2018 to 2021, its LNG demand in the coming years might be much lower than the contracted LNG volumes.

Table 2: German companies' LNG contracts and heads of agreements

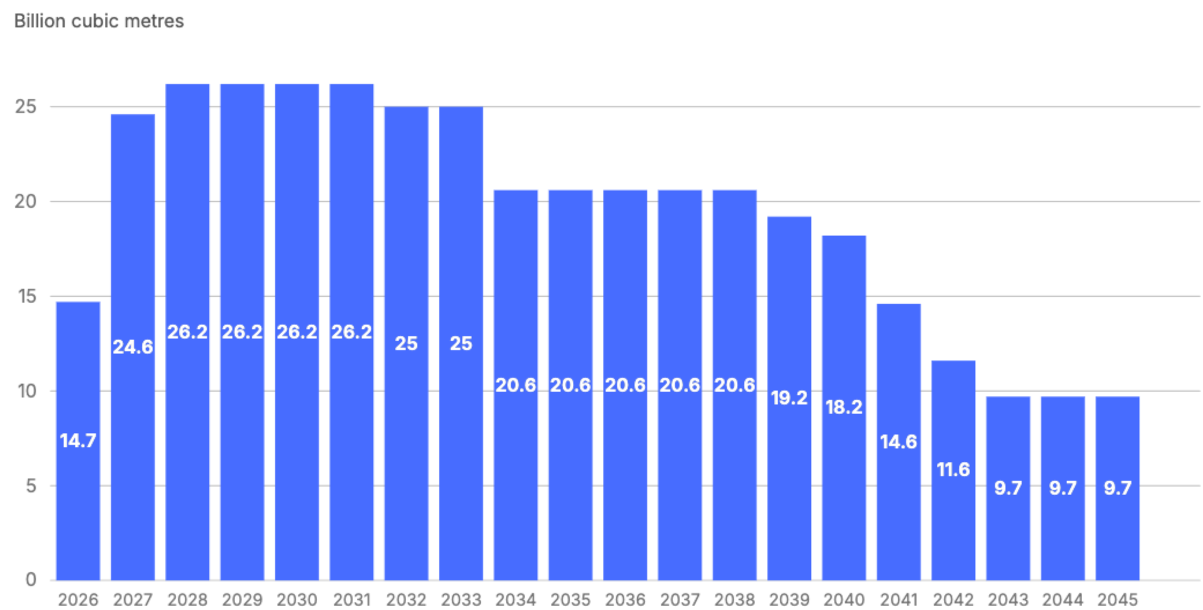
Buyer	Seller	LNG source	Volume (bcm/year)	Start date	Duration (years)
BASF	Cheniere	US	1.1	2026	17
EnBW	Venture Global	US	2.8	2026	20
	ADNOC	UAE	0.8	2028	15
RWE	Woodside	Global portfolio	1.2	2025	7
	QatarEnergy/ ConocoPhillips	Qatar	2.8	2026	15
	Sempra	US	3.0	2027	15
SEFE	Yamal LNG	Russia	3.9	2018	3
	ConocoPhillips	Global portfolio	0.9	2024	10
	ADNOC	UAE	1.0	2025	15
	Delfin	US	2.1	2026	8
	Southern Energy	Argentina	2.8	2027	20
	Venture Global	US	4.1	2027	20
Uniper	Woodside	US	1.4	2026	8
	Woodside	Global portfolio	1.4	2026	13
	Tourmaline	Canada	0.8	2028	13

Sources: Company press releases.

German state-owned energy company SEFE (Securing Energy for Europe) has signed several agreements for LNG from different regions. Chemical company BASF signed a contract with Cheniere for US LNG in 2023.

If all of Germany's current LNG import agreements materialise, the country would be contracted to import 26.2bcm of LNG in 2030 — almost three times its 2025 LNG import volumes — and 10bcm in 2045, when it aims to achieve greenhouse gas neutrality.

Figure 5: Germany’s contracted LNG import volumes



Source: Company press releases.

Regardless of these contracts, German efforts to reduce gas demand and scale up renewables deployment will boost energy security, even as the country aims to double down on using gas power plants as a backup for solar and wind.

The German government plans to support the construction of hydrogen-ready gas-fired power plants. The government’s initial proposals were to build up to 20 gigawatts of gas power capacity by 2030, but it has scaled this back to 10 gigawatts.[29,30] The new power stations need to be carbon neutral by 2045. They could potentially feature carbon capture and storage. But the technical and economic challenges mean carbon capture is not a near-term solution for these assets.

The EU's REPowerEU plan to end its reliance on Russian fossil fuels helped enhance Germany’s energy security through diversification and demand reduction. But Germany’s continued reliance on gas and LNG imports threatens its energy independence.

[29] Enerdata. Germany plans to develop 20 GW of gas power plant capacity by 2030. 11 April 2025.
[30] Reuters. Germany scales back plans for new gas-power generation in decarbonisation compromise. 14 November 2025.

Germany's unrealistic shift from gas-fired power to hydrogen

Key findings

- Germany's decarbonisation strategy relies heavily on hydrogen produced using renewable energy. Yet hydrogen production costs and project execution risks cast doubt on converting gas power plants to hydrogen at the required scale and speed.
- Despite these challenges, Germany aims to have hydrogen power capacity equivalent to 87% of its current gas-fired fleet by 2045.
- If Germany significantly scales up renewables, battery storage, cross-border grid connections and demand-side management, IEEFA estimates that the country could potentially source about 5% of its electricity from natural gas and hydrogen combined by 2045.
- Government subsidies for gas power plants might delay investment in renewables and grid upgrades, locking in carbon-intensive assets and undermining the energy transition, in IEEFA's view.

Natural gas-fired power generation continues to play a key, though increasingly contested, role in Germany. While the country's energy transition prioritises renewables, natural gas and hydrogen are the federal government's preferred sources of dispatchable electricity capacity to balance the intermittency of solar and wind.

German government strategies frame natural gas as a temporary "bridge fuel", progressively replaced by hydrogen-ready infrastructure. However, persistent gas generation, extensive public support mechanisms and uncertainties surrounding the supply of hydrogen produced using renewable energy (green hydrogen) raise fundamental questions about the credibility, cost and coherence of Germany's pathway to reaching net-zero emissions by 2045.

Germany's planned transition from gas to hydrogen power

Germany's natural gas-fired power capacity is entering a structural transition as the country moves toward a climate-neutral electricity system by 2045. The political discussion about the role of gas power intensified after Germany's 2011 announcement to phase out nuclear and the energy security shocks of recent years. Successive federal governments have argued that maintaining a pool of controllable, fast-ramping capacity is essential to avoid electricity shortfalls during so-called "dunkelflaute" events — prolonged stretches of low wind and sunlight that can strain the grid.

Germany's current natural gas power capacity is roughly 31–32 gigawatts (GW). The fleet includes both combined- and open-cycle gas turbine plants. The country relies more heavily on the higher efficiency combined-cycle plants.

Germany plans to retrofit existing gas plants to burn hydrogen to help meet its decarbonisation goals. By 2030, the country plans to replace part its gas fleet with 10GW of hydrogen-ready plants, designed to run initially on natural gas and convert to clean hydrogen as hydrogen supply increases.[31] Beyond 2030, Germany's Network Development Plan's three scenarios for 2045 do not have exact gas power capacity values but show a clear trajectory: conventional gas capacity steadily declines as hydrogen-capable and fully hydrogen-fuelled plants grow.[32] Hydrogen power plant capacity will rise to 17–28GW by 2040–2045 in the three Network Development Plan scenarios, according to the Federal Network Agency. This means the country aims to have hydrogen power capacity equivalent to about 87% of its current gas-fired fleet by 2045. This reflects hydrogen plants' role as firm, dispatchable capacity backing a predominantly renewable system.

Across all pathways, the system shifts from relying on natural gas plants to provide baseload and flexible generation toward hydrogen assets that run only when renewables are insufficient.

However, the feasibility of using green hydrogen to decarbonise gas generation remains highly uncertain. Germany's strategy relies heavily on the large-scale availability of green hydrogen, yet production of the fuel needs to be scaled up significantly to meet future demand. Production costs, import dependencies, infrastructure constraints and project execution risks cast doubt on whether gas-to-hydrogen conversion can occur at the required scale and speed.

Germany plans to import green hydrogen from projects including Hyphen in Namibia, for example. But projects such as these are overambitious and may never materialise because hydrogen transportation costs make them uncompetitive.

[31] German Federal Ministry for Economic Affairs and Energy. Hydrogen: a key element of the energy transition.
[32] German Federal Network Agency. Szenariorahmen zum Netzentwicklungsplan Strom 2037/2045, Version 2025. June 2024.

Will gas power undermine Germany’s energy security?

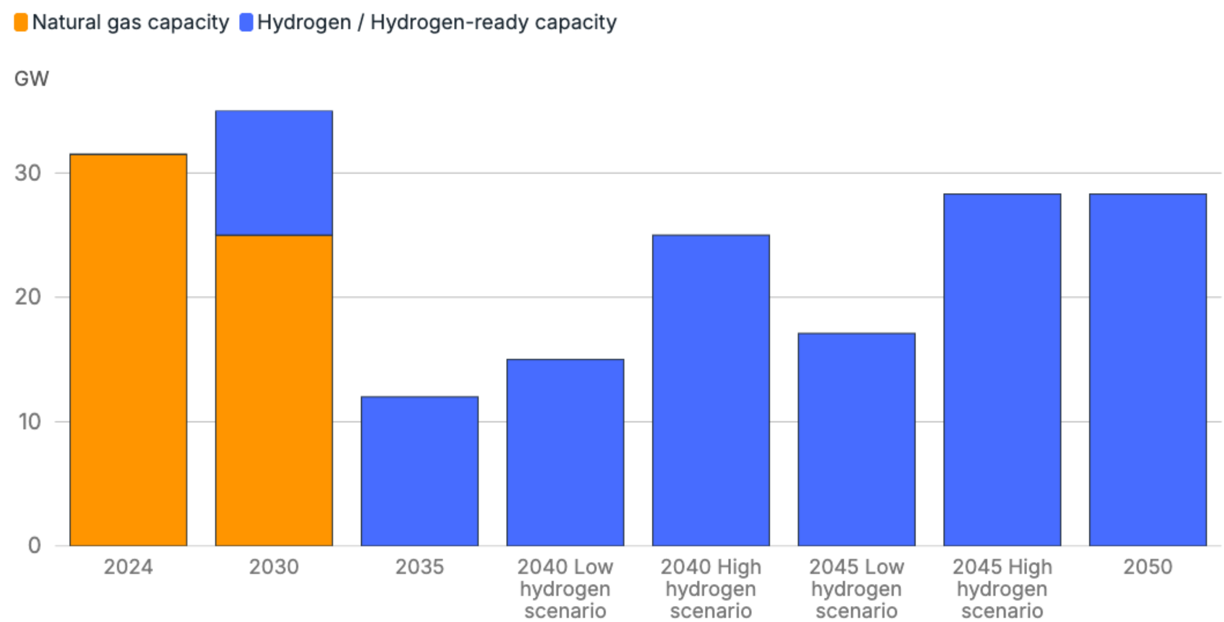
The disruption in natural gas supply following Russia’s 2022 invasion of Ukraine highlighted the energy security risks for Germany of relying on fossil fuel imports. Germany’s plan to construct at least 10GW of new gas power plants will increase the country’s dependence on gas imports. This could expose Germany to gas supply disruptions caused by geopolitical issues as well as high and volatile LNG prices. In 2025, Germany sourced 92% of its LNG imports from the US, the most expensive LNG for EU buyers.

Germany plans to switch its gas power plants to run on hydrogen. If Germany’s hydrogen pipeline network is delayed or if hydrogen production or imports fall short, the country could extend its reliance on gas as a fuel. Successfully switching its gas plants to run on hydrogen may still involve relying on foreign suppliers. This would effectively replace one import dependence with another, meaning energy security issues could persist.

Table 3: German government natural gas and hydrogen power plant capacity outlook

Year	Natural gas capacity	Hydrogen/hydrogen-ready capacity	Source
2024	~31.5GW	0GW	AG Energiebilanzen and Federal Network Agency
2030 (official)	Unspecified (expected decline)	10GW hydrogen-ready	Federal Ministry for Economic Affairs and Climate Action
2035 (official)	0–10GW (estimate)	Additional hydrogen-ready capacity (GW not fixed)	Federal Ministry for Economic Affairs and Climate Action, Federal Climate Action Act
2040 (scenario)	0–10GW (estimate)	~15–25GW (scenario dependent)	Network Development Plan, Federal Climate Action Act
2045 (scenario)	0GW	17.1–28.3GW	Network Development Plan
2050 (no target)	0GW	No official federal target	

Figure 6: German government natural gas and hydrogen power plant capacity outlook

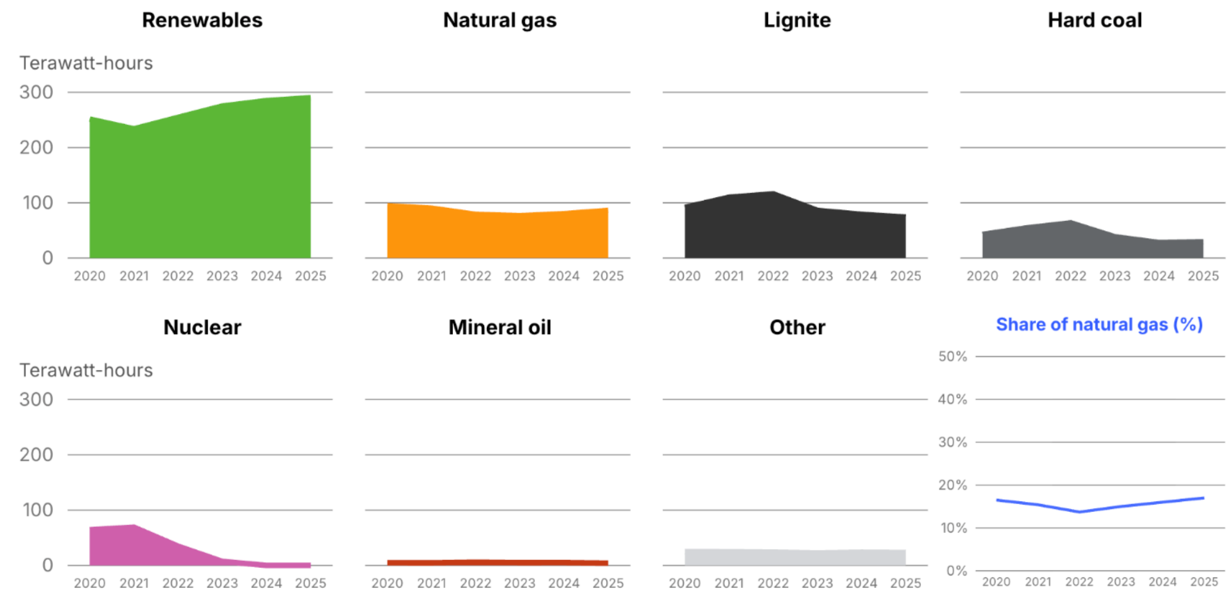


Sources: Federal Network Agency, German Federal Ministry for Economic Affairs and Climate Action, Arbeitsgemeinschaft Energiebilanzen, German Federal Climate Action Act.

Gas and hydrogen power generation

Germany's gas-fired electricity generation has fluctuated over the years, influenced by the availability of renewable energy and the price of natural gas. In recent years, Germany's gas generation has been about 80–100 terawatt-hours annually, roughly 15–16% of the country's total electricity production. It is concerning that this share remains stable and shows no sign of decreasing. Gas plants mainly cover peak demand and provide flexibility to accommodate renewable generation.

Figure 7: German gross electricity production



Source: AG Energiebilanzen.

Germany’s energy transition plan envisions a transformation of the country’s power generation mix by 2045, when it aims to have 80–90% of its electricity come from renewables.

Germany's goals require 2045 hydrogen power generation to be lower than current natural gas generation. The exact figures for 2045 depend on the extent to which the country uses green hydrogen and other low-carbon gases, such as biogas, in the generation mix. The government expects that hydrogen-fired generation will contribute around 10–15% of Germany’s total electricity production in 2050, with a significant planned shift toward hydrogen and synthetic methane in the gas mix. In IEEFA’s view, the country is unlikely to achieve such a high percentage.

Gas plant subsidies distort EU state aid rules

The German government has introduced schemes to support the development of new natural gas power plants, such as the capacity reserve mechanism (Kapazitätsreserve). This mechanism and the subsidies it provides are crucial to the financial viability of gas plants.

The German government also offers state aid for investments in power plants that use gases such as hydrogen. While this aligns with the country’s broader climate goals, the government has faced criticism for breaching EU state aid rules.[33] These subsidies effectively prop up fossil fuel-based generation and could hinder Germany's energy transition and distort the energy market. The European Commission has expressed concerns that the state aid could undermine efforts to

[33] Beyond Fossil Fuels. Public money, private interests: EU governments usher through fossil gas subsidies worth billions. 28 October 2025.

decarbonise and lead to excess gas generation, making it more difficult to achieve long-term climate goals.[34]

State support for new fossil fuel infrastructure could be seen as inconsistent with the EU's European Green Deal and European Climate Law, which call for ambitious decarbonisation efforts. In IEEFA's view, these subsidies might delay investment in renewables and grid upgrades, locking-in carbon-intensive power generation.

Planned capacity mechanism

Germany also plans to introduce a capacity mechanism (CM) by 2028 to incentivise gas-fired plants to play a backup role, compensating them to be on standby even if they are not generating electricity.[35] The CM will support the operation of gas plants that may otherwise become economically unviable as the cost of renewables and battery storage continues to fall. The CM could prolong the life of inefficient or polluting assets and delay the transition to a carbon-neutral grid.

In IEEFA's view, Germany should review the CM design to avoid keeping gas plants open that would otherwise exit the market based on their marginal costs, thus allowing higher renewables penetration.

Firstly, the CM should be capacity neutral. All generation types, including renewables, should be eligible for payments. Allowing the CM for thermal only is discriminatory.

Secondly, Germany should update its capacity eligibility assessments to reflect more than just firm capacity. Using the current firm capacity definition (more than 95% probability of availability) implicitly excludes wind and solar from the CM. Germany should use a new definition of firm capacity: a compromise between the current one and nameplate capacity, so that wind and solar can have some, even minimal, share of their capacity eligible for the CM.

Thirdly, Germany should reduce the hours eligible for capacity payments. The CM is actually needed for less than 300 hours a year, corresponding to the one or two winter weeks with very low solar and wind generation. It is irrational for a combined-cycle gas turbine to receive a capacity payment for 8,760 hours when it supplies energy to the grid for less than 300 hours a year. Capacity payments reflect a much higher cost to the system than remunerating these winter hours on an energy-only basis. Therefore, in IEEFA's view, the capacity payment should be entirely reassessed to reflect the actual costs the system should bear: an energy-only remuneration during dunkelflaute winter hours.

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[34] Clean Energy Wire. EU state aid rules hurdle for German plans for state support to build new gas power plants. 27 June 2023.
[35] Next Kraftwerke. Capacity Market: Future-proof Design Instead of a Step Back into Old Structures. 10 September 2025.

Alternatives to a gas- and hydrogen-dependent future

While hydrogen-capable gas plants are the government's preferred solution for dispatchable power, several alternatives could significantly reduce the need for natural gas and hydrogen in the long term:

1. **Massive expansion of renewables.** The most straightforward path to reducing gas and hydrogen reliance is to overbuild wind and solar capacity. A significant surplus of renewable generation would reduce the impact of dunkelflaute events.

2. **Battery storage.** Combining renewables with large-scale battery storage (both utility-scale and distributed) can smooth over short-term power imbalances of up to a day. Batteries can also reduce peak demand. Germany is actively promoting battery storage, with capacity growing rapidly, but the technology is still insufficient for multi-day periods of low renewables output.

3. **Demand-side management and vehicle-to-grid technology**. Leveraging the flexibility of demand from industrial loads to smart electric vehicle (EV) charging can significantly reduce the need for peak generation plants. A future fleet of millions of EVs could act as a massive distributed battery through vehicle-to-grid technology, feeding power back to the grid during periods of high demand.

4. **Long-duration energy storage**. Hydro pumped storage power plants (PSPPs) are the best solution to store power for extremely long durations. They allow for seasonal and even annual water storage for power generation, depending on the reservoir capacity. While PSPPs are usually built in mountainous regions to take advantage of natural elevation gaps, even relatively flat countries can use this technology with less than a 100-metre difference in elevation between two reservoirs. Lithuania’s Kruonis PSPP is one of the best examples, with only a 60-metre elevation difference.[36] PSPPs require significant initial capital expenditure. The technology’s potential to respond to the intermittency of wind and solar remains untapped. Advanced compressed air energy storage and thermal energy storage are also promising long-duration solutions.

5. **Geothermal power**. Deep geothermal energy has the potential to provide carbon-free baseload power and heat. While geothermal power only provides a small share of Germany’s electricity generation, technological advances could significantly expand its role.

6. **Enhanced grid interconnections**. Strengthening cross-border connections with neighbouring countries would allow Germany to import electricity from regions with different weather patterns (for example, hydropower from Scandinavia or solar from Southern Europe), effectively diversifying the risk of a localised dunkelflaute.

[36] Ignitis Gamyba. Kruonis Pumped Storage Hydroelectric Power Plant (KPSHP).

What is the role of gas and hydrogen power plants in Germany's 2045 electricity system?

Solar and wind generation will dominate Germany's future electricity system. The country plans to rely on natural gas power plants to support these technologies. But it will need to decarbonise its fleet of gas plants as it moves towards its 2045 climate neutrality target. It aims to achieve this by both converting existing natural gas power stations to run on hydrogen and constructing new hydrogen-ready gas plants.

But hydrogen power plants will likely play a smaller role than German government forecasts because of their high costs and low efficiency. Converting gas plants to run on hydrogen may also take longer than expected. The country may instead consider decarbonising gas plants with carbon capture and storage (CCS) technology. However, the lack of commercial-scale gas CCS reference projects, substantial subsidy requirements and long development timelines mean this is a high-risk strategy. Therefore, given the high costs and uncertain timescales of decarbonising gas power stations, Germany should prepare for a 2045 power mix with minimal gas or hydrogen generation by significantly scaling up renewables, storage, grid connections and demand response.

A vision for 2045: A power mix with minimal gas and hydrogen

Germany should aim for a 2045 power mix with minimal natural gas- and hydrogen-fired generation. This would require a reliance on the technologies below. Such a strategy would see Germany spearhead Europe's energy transition and would forge pathways for the rest of the continent to follow.

In this scenario, Germany's 2045 power mix would look like this:

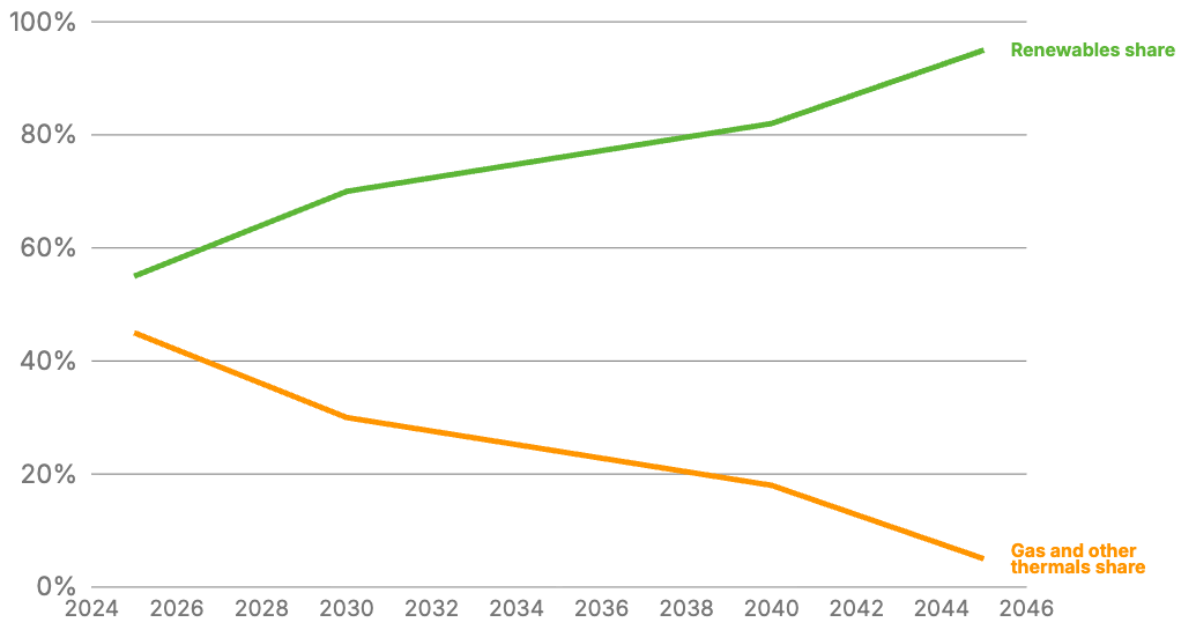
- Renewables (~95–98% of capacity). Onshore wind (~150–200GW), offshore wind (70GW) and solar photovoltaics (~400–600GW) would form the bedrock, generating most of the year's electricity.
- Long-duration and seasonal storage (~5% of annual generation and a large share of capacity needs). Hydrogen salt caverns, filled via electrolysis during sunny and windy summers, would feed hydrogen into turbines or large-scale fuel cells during the winter. This would be complemented by about 5GW of pumped storage power plants. These two technologies would provide the terawatt-hours of energy storage needed for periods of low wind and sunlight lasting several weeks.

- Short-duration storage. Gigawatt-hours of utility-scale, industrial and commercial, and residential battery storage would smooth out daily variations in renewables generation and regulate grid frequency.
- Demand response. A smart grid would see industrial processes, EV charging and household appliances automatically adjust their consumption to match renewable energy availability, creating a flexible and efficient system.
- Baseload from geothermal and biomass. A mature geothermal sector (potentially 10–20GW) and sustainably managed biomass plants would provide the final layer of firm, predictable power.
- Enhanced grid interconnections. Stronger grid connections with neighbouring countries would allow Germany to import more electricity when domestic renewables output dips. This would enhance energy security and could lower electricity prices.

In this scenario, electricity system security no longer rests on combustion turbines but on the intelligent interplay of a diversified, resilient and overwhelmingly renewable-based system backed by multi-faceted storage solutions.

Figure 8 shows the share of renewables and gas/hydrogen in Germany's power mix if all the developments mentioned above materialise.

Figure 8: Germany's 2045 power mix under a scenario with minimal gas and hydrogen generation



Sources: IEEFA, German Federal Network Agency, German Federal Ministry for Economic Affairs and Climate Action, German Federal Climate Action Act.

The case against carbon capture for Germany's gas power sector

- Carbon capture and storage (CCS) is not a near-term solution for Germany's plan to build 10 gigawatts of new gas power plants. It would cost the country hundreds of billions of euros to apply CCS to these projects.
- Europe has no successful CCS projects attached to gas power plants, in part because of prohibitively high costs and technical risks.
- If Germany shifts its gas fleet to blue hydrogen with CCS, the country would lock in long-term gas demand and require massive transport and storage infrastructure for both hydrogen and carbon dioxide.
- Relying on CCS for gas-fired power could delay investments in more viable decarbonisation alternatives, such as renewables, energy storage and green hydrogen.

Context: Germany's 10GW gas power strategy

Germany's coalition government has committed to ensuring sufficient electricity capacity by 2030, as the country moves towards phasing out coal generation by 2038. To meet this need, the government intends to tender up to 10 gigawatts (GW) of new gas-fired power plants. These are expected to bridge security of supply during "dunkelflaute" winter periods of low wind and solar output.

A key unresolved question is whether these new gas assets should be made future-proof by integrating carbon capture and storage (CCS). On paper, CCS could decarbonise gas power generation. Yet in practice, it remains unproven, costly and heavily constrained by Germany's legal and infrastructural environment.

What is CCS?

CCS refers to the process of capturing carbon dioxide (CO_2) from large point sources (such as power plants or cement kilns), compressing it and transporting it (via pipeline, ship or rail) for permanent underground storage in saline aquifers or depleted oil and gas reservoirs.[37]

The first projects emerged in the 1970s in North America, mainly to support oil extraction through enhanced oil recovery. Today, around 50 million tonnes of carbon dioxide ($MtCO_2$) is captured globally each year, but 73% is still used for oil recovery, not permanent storage.[38] Europe has just

[37] National Grid. What is carbon capture and storage? 26 March 2024.
[38] World Resources Institute. 7 Things to Know About Carbon Capture, Utilization and Sequestration. 16 May 2025.

five operational CCS projects, capturing 2.7MtCO_2 per year across the Netherlands, Norway, Iceland, and Hungary. None involve gas power stations.[39]

Despite its prominence in EU climate strategies, CCS has never been deployed on new-build gas power in Germany nor at scale on retrofits anywhere in the world. This is in part due to the technical and economic challenges of integrating CCS into existing or newly built facilities.

Challenges of CCS for gas power

- **No track record**: Europe has no successful CCS projects attached to gas-fired power plants. Previous efforts in the UK and EU were cancelled because of high cost and poor performance.[40,41] The technology readiness level for gas-fired CCS is seven out of 11, or the pre-commercial demonstration phase, according to the International Energy Agency.[42]
- **Costs**: IEEFA estimates that CCS costs for the power and heat sector in Europe are more than €150/tonne of CO_2, including €64/tonne for capture and €88/tonne for transport and storage. [43] This is around double the current EU Emissions Trading System price of €76.[44] Assuming the EU Emissions Trading System price remains at similar levels over the coming years, there is little economic incentive for infrastructure owners to apply CCS without subsidies or other forms of financial support.
- **Capture rates**: Even leading projects underperform. An IEEFA review of 13 operating CCS projects globally found that most captured below design levels of 90%, while some failed outright.[45] This highlights the continued technical challenges of CCS as a solution and the potential for further cost escalation per tonne.
- **Timelines**: CCS projects take 10–15 years to develop because of permitting, infrastructure and cross-border agreements. With Germany planning tenders for gas plants in the 2020s, the country will not realistically have any gas-fired CCS projects operational by 2030. Delays at flagship European CCS projects such as Northern Lights in Norway and Porthos in the Netherlands illustrate the risks: Both are over budget and behind schedule.[46,47]
- **Infrastructure gaps**: Germany has no operational CO_2 pipeline network. Legal barriers have historically blocked permanent CO_2 storage in the country. There are four potential transport projects across Germany, linking to storage sites in Belgium and the Netherlands.[48] These transport projects remain at the early stages of planning and require legislative changes, project final investment decision and economic support before a lengthy construction process can begin. Until Germany ratifies international agreements, exporting CO_2 to Norway

[39] International Energy Agency. CCUS Projects Database. April 2025.
[40] UK Committee of Public Accounts. Carbon Capture, Usage and Storage. 7 February 2025.
[41] UK Parliament. Written evidence submitted The UK Advanced Power Generation Technology Forum (CCS11).
[42] International Energy Agency. CCUS technology innovation.
[43] IEEFA. Carbon capture and storage: Europe's climate gamble. 10 October 2024.
[44] Ember. European electricity prices and costs.
[45] IEEFA. The carbon capture crux: Lessons learned. 1 September 2022.
[46] Reuters. Carbon capture project in Norway temporarily halted by high costs. 26 April 2023.
[47] NL Times. Dutch CO2 storage project nearly three times over budget. 8 March 2024.
[48] International Energy Agency. CCUS Projects Database. April 2025.

or Denmark is uncertain. Without this, domestic offshore storage capacity will not be sufficient to support CCS at scale.

- **Storage**: Offshore sites are technically feasible but costly. Even leading sites, such as Sleipner and Snøhvit in Norway, have experienced unexpected CO_2 migration and capacity problems.[49]

Legal and subsidy support in Germany

Before November 2025, Germany's Carbon Dioxide Storage Act restricted CCS to pilot projects and gave states the right to opt out. This halted early projects in Schleswig-Holstein and Brandenburg. However, following an amendment by the federal government, a revised Carbon Dioxide Storage and Transport Act came into force in November 2025.[50] The revision now permits capture and storage on a larger scale, allowing for both onshore and offshore CO_2 storage, and enabling development of a national CO_2 pipeline network. The legislation also designates that investment in transport and storage infrastructure is in the overriding public interest. This status intends to simplify and accelerate the permitting process, leading to increased CCS use.

A core purpose of the legislative change is to open CCS use to combat emissions in hard-to-abate sectors, such as cement and lime production, basic chemicals and waste incineration. The law only excludes CCS for coal power plants, suggesting that gas-fired power generation may be applicable for future government support.

German Economy Minister Katherina Reiche announced a €6 billion funding initiative for CCS projects in October 2025.[51] This will see firms participate in competitive auctions for climate protection contracts in 2026. The contracts will provide 15-year subsidies for projects that demonstrate the largest emissions reductions at the lowest public cost.[52] While the announcement implies that the initiative will support hard-to-abate sectors, it does not explicitly exclude support for gas-fired power plants.

Germany is behind other European countries such as Norway and the UK in providing the required legislative and financial support for large-scale CCS adoption. The UK is much further progressed. In 2025, it announced funding support for the Net Zero Teesside, a new-build gas-fired power station with CCS. The exposure to the UK government and electricity consumers is significant. The project may require £10 billion of subsidies for the power plant and £7 billion for transport and storage.[53] This is to capture and store 2MtCO_2 equivalent from 860 megawatts of abated capacity.[54] This is a first-of-a-kind project, and future costs should reduce through learnings. However, the implication

[49] IEEFA. Norway's Sleipner and Snøhvit CCS: Industry models or cautionary tales? 14 June 2023.
[50] Federal Government of Germany. Weg frei für die Speicherung von Kohlendioxid. 28 November 2025.
[51] Reuters. Germany launches 6 bln eur industrial decarbonisation program, includes CCS technology. 6 October 2025.
[52] Clear Blue Markets. Germany Rolls Out an Industrial Climate Plan, Integrating CCS for the First Time. 7 October 2025.
[53] IEEFA. The runaway cost of UK carbon capture and storage subsidies. 16 July 2025.
[54] UK Planning Inspectorate. The Net Zero Teesside Project. 29 October 2025.

remains that if Germany were to attempt to decarbonise its 10GW ambition through CCS, the subsidy costs could run into hundreds of billions of euros.

CCS, gas and blue hydrogen

The government's 10GW strategy also overlaps with debates on hydrogen. Blue hydrogen (made from natural gas with CCS) is often touted as a decarbonisation option. However, like CCS for gas power plants, the CO_2 capture technology is unproven, and the costs are high. This is in addition to the same transport, storage and associated legal issues discussed earlier.

Using CCS alongside steam methane reforming to create blue hydrogen has a technology readiness level of nine, the early adoption phase. [55] This means it is more technically advanced than using CCS for the power and heat sector. CO_2 capture costs for hydrogen production are also lower at €55/tonne, while transport and storage are the same at €88/tonne, with a cumulative cost of €143/tonne.[56] This is 88% above current EU Emissions Trading System prices.[57]

If Germany shifts its gas fleet to blue hydrogen with CCS, it would lock in long-term gas demand, requiring massive transport and storage infrastructure for both hydrogen and CO_2 — creating dual infrastructure lock-in.

Conclusions

Germany's 10GW gas power plan aims to guarantee supply security post-coal and nuclear. The country faces significant technical and economic risks if it uses CCS to try to decarbonise gas-fired power. There is no track record of CCS on gas plants in Germany or Europe, costs are prohibitively high, timelines extend beyond 2030, and infrastructure does not exist. Legal reforms are only just emerging and remain incomplete, while using blue hydrogen with CCS risks locking in natural gas use and may fail to deliver climate neutrality.

Transport and storage remain the weakest links: Without pipelines and ratified cross-border storage agreements, CCS cannot scale. CCS is not a near-term solution for Germany's 10GW gas requirement. At best, it is a long-term option contingent on heavy subsidies, regulatory change and infrastructure build-out. The risk is that reliance on CCS could delay more viable alternatives (renewables, storage, green hydrogen) and expose Germany to high costs and project failures.

[55] International Energy Agency. CCUS technology innovation.
[56] IEEFA. Carbon capture and storage: Europe's climate gamble. 10 October 2024.
[57] Ember. European electricity prices and costs.

German issuers exposed to transition risks from fossil fuel assets

- German utilities planning to rely on commercially unproven technologies such as carbon capture face greater uncertainty in achieving direct emissions reductions.
- Fossil fuel-exposed German utilities have not yet set clear reduction pathways for indirect emissions, leaving their business activities increasingly pressured by climate transition risks over time.
- Investing in new gas power plants could limit German utilities' ability to pursue climate-aligned solutions, potentially compounding credit implications and undermining sustainable bond programmes.

Major German utilities that own gas and coal power plants, as well as gas transmission and storage assets, will likely be exposed to elevated climate transition risk over time. While the German government could bear some financial responsibility through its aid, subsidies, equity injections or lending support, significant risk will remain within the private sector. Fossil fuel exposure without a credible climate transition plan could pose long-term credit risk through multiple channels, including market, technology, regulatory, social and governance factors.

Germany has around 70 gigawatts (GW) of gas- and coal-fired capacity, relatively concentrated among major unregulated, diversified utility companies including RWE, EnBW and Uniper (Figure 9). These companies' credit profiles are exposed to energy transition risks against the backdrop of Germany's renewable power targets. Between 2025 and 2028, considering plants currently under construction or in test operation, Germany expects to add around 2GW of new gas-fired capacity. State-backed EnBW accounts for two-thirds of this new capacity. German municipalities are primarily developing the rest (Figure 10).

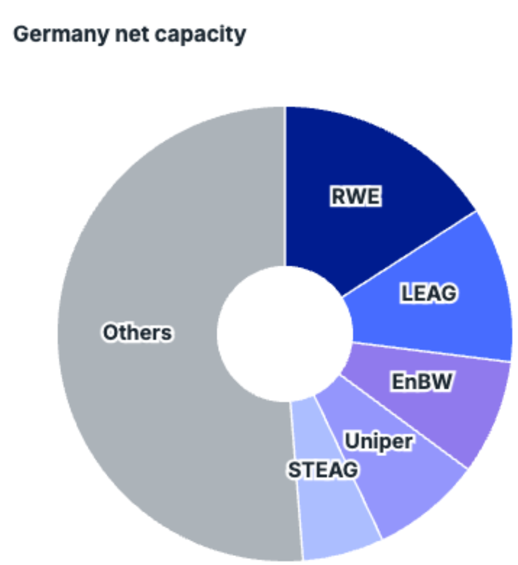
Moreover, regulated gas networks are exposed to electrification and risks of a secular decline in gas demand. Germany has 16 gas transmission system operators (TSOs). Open Grid Europe (OGE) is the largest, operating a network of 12,000km, followed by Ontras with 7,500km. EnBW owns 100% of Ontras.

Table 4: Fossil fuel exposure of selected German utilities and gas TSOs

	Diversified utility					Regulated gas TSO	
	RWE	**EnBW**	**Uniper**	**LEAG**	**E.ON**	**OGE/VGT**	**Ontras**
Gas-fired power	X	X	X		X		
Coal-fired power	X	X	X	X			
LNG/gas		X	X		X	X	X

Sources: Company reports, IEEFA.

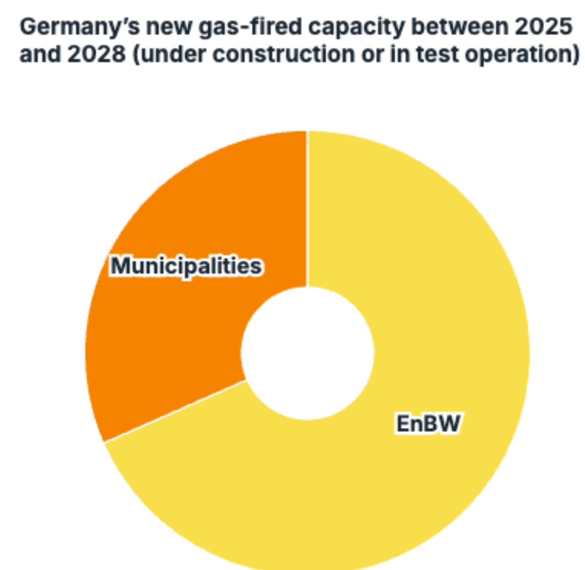
Figure 9: Germany's top-five power generators account for nearly half of the country's coal- and gas-fired capacity



Sources: German Federal Network Agency, IEEFA.

Note: As of 14 May 2025.

Figure 10: EnBW dominates upcoming gas-fired capacity



Sources: German Federal Network Agency, IEEFA.

Note: As of 14 May 2025.

Climate transition plans face execution and market challenges

German utilities have disclosed plans to address energy transition risk for their gas and coal power plants and other gas-related businesses. However, in IEEFA's view, some of their decarbonisation levers will likely face execution challenges (Table 5). The utilities also have differing Scope 1, 2 and 3 emissions profiles and emissions reduction targets (Figure 11).[58] Risks will likely increase where emission reduction strategies rely on technologies that are not yet commercially proven, including carbon capture and storage (CCS) and hydrogen.

Table 5: German utilities' and gas TSOs' planned decarbonisation levers

	Diversified utility					Regulated gas TSO	
	RWE	**EnBW**	**Uniper**	**LEAG**	**E.ON**	**OGE/VGT**	**Ontras**
Gas-fired power	CCS, hydrogen	Hydrogen	CCS, hydrogen/biofuels conversion		Substituting with renewables		
Coal-fired power	Phase-out (2030); transition to biomass	Phase-out (2028)	Phase-out commercial capacity (2029)	Phase-out			
LNG/gas		Hydrogen	Hydrogen/low-carbon fuels portfolio		Renewables, electrification	Hydrogen	Hydrogen

Sources: Company reports, IEEFA.

[58] According to Greenhouse Gas Protocol, Scope 1 emissions are direct emissions from owned or controlled sources; Scope 2 emissions are indirect emissions from the generation of purchased energy; and Scope 3 emissions are all indirect emissions (not included in Scope 2) that occur in the value chain of a reporting company, including both upstream and downstream emissions.

Gas-fired power exposure varies among utilities. The long-term cash flow implications are likely material for Uniper and RWE, and to a lesser extent EnBW. This arises from the unclear prospects of gas-fired plants' CCS retrofits and hydrogen readiness. German utilities' gas power exposure includes the following:

- **Gas accounts for half of Uniper's 9GW of power capacity in Germany.** Uniper's decarbonisation would rely largely on retrofitting a significant part of its gas-fired plants with CCS or to run on hydrogen or biofuels.
- **RWE will likely remain one of Europe's highest-emitting utilities by 2030**, despite being relatively advanced in renewable energy development. RWE still has 15GW of gas-fired capacity, including 4GW in Germany. Decarbonising the company's gas fleet would depend on the successful deployment of hydrogen-ready or CCS retrofits. RWE also plans to build a 300-megawatt (MW) green hydrogen project on the site of the Emsland gas-fired plant by 2027. Green hydrogen is produced using renewable energy.
- **Since 2022, EnBW has been replacing three coal-fired units with gas power plants with a combined capacity of 1.5GW**. These will contribute substantially to Germany's near-term gas-fired capacity growth. EnBW invested €1.4 billion in thermal generation between 2023 and 2024. While this forms part of the company's coal phase-out plan, achieving its 2035 climate neutrality target would hinge on a fuel switch to hydrogen.
- **Long-term supply contracts could add market risks.** Uniper, RWE and EnBW have entered into heads of agreement and contracts to import LNG and gas for up to 15–20 years, despite the companies' plans to decarbonise gas-fired plants. These contractual obligations expose the companies to the risk of long-term underutilisation of gas power plants, potentially locking them into uneconomic supply commitments.
- **By contrast, E.ON has very low exposure to gas power.** The company operates small-scale, embedded gas-fired combined heat and power units. It plans to convert these units to generate electricity and heat using renewable sources.

Utilities with coal power plants generally have clear phase-out plans. RWE and LEAG's significant lignite coal capacity could expose them to decommissioning costs and liabilities. RWE booked €6.3 billion in provisions as of 2024 related to coal mining damage. The company's diversification has helped mitigate its credit exposure. RWE and LEAG pass their financial burdens onto the German government to some extent through the early exit agreement and state-aid package.[59]

- **Uniper has phased out commercial coal capacity in Germany**, with its remaining hard coal plants — Scholven B and C (690MW), Staudinger 5 (510MW) — declared as system-relevant in grid reserve.[60]

[59] Germany's coal phase-out law requires coal power to end by 2038. To facilitate an earlier exit from lignite power, Germany has reached agreements with RWE and LEAG to compensate them with €4.35 billion: €2.6 billion for RWE's plant in the Rhineland and €1.75 billion for LEAG's plants in Saxony and Brandenburg.

[60] German grid reserve power plants are those that have been marked for closure but may not be shut down because they have been categorised as important for the system.

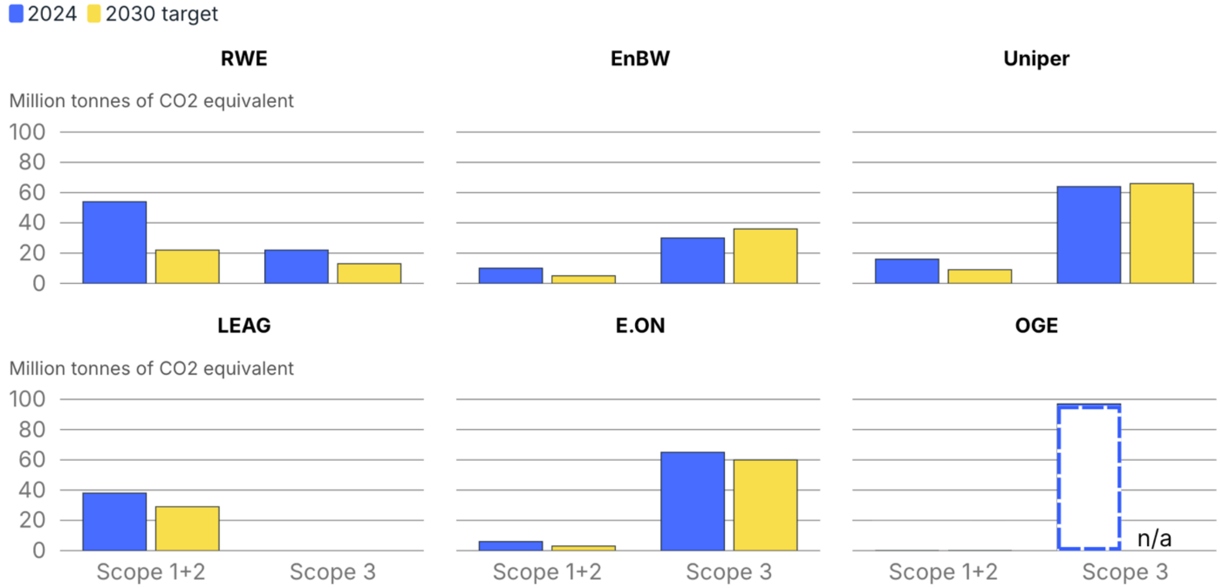
- **EnBW plans to phase out coal capacity by 2028.** The company aims to reduce its coal capacity from 3.1GW as of 2025 to 1.4GW by 2026 by converting the Heilbronn plant to gas and selling Lippendorf lignite assets to Czech energy group EP Group.[61,62] It plans to reduce its coal capacity to 1.1GW by 2027 with the conversion of Altbach/Deizisau. It has 1.8GW of coal in grid reserve.

German utilities' gas-related businesses are reflected in their high Scope 3 emissions: Uniper has gas operations along the value chain, making it one of the most fossil fuel-exposed. It has a fleet of four LNG vessels under charter and 7.2 billion cubic metres of gas storage capacity. Scope 3 emissions dominate its emission profile, stemming from the use of sold products, reflecting the company's exposure to climate transition that will likely exacerbate commodity volatility. But Uniper has not set an ambitious Scope 3 decarbonisation pathway, targeting still 66 million tonnes of CO_2 in 2030 and 57 million tonnes in 2035. The company aims to maintain annual gas sales of 180–200 terawatt-hours in Germany, Austria and Switzerland over the medium term. It plans to expand its pipeline gas and LNG sourcing portfolio. This strategy is misaligned with Germany's climate goals and exposes the company to the trend of declining gas demand. Uniper's other projects include a hydrogen storage facility in Lower Saxony and a 30MW green hydrogen plant in Saxony-Anhalt. But they are unlikely to materially drive emissions reduction, and their scale is expected to remain a minor part of Uniper's overall business.

- **E.ON has one of the highest Scope 3 emission profiles,** totalling around 60 million tonnes of CO_2 equivalent in 2024, driven primarily by purchased electricity sold and gas sold to end customers. E.ON states that it aims to drive low-emissions power for customers through facilitating electrification and energy efficiency solutions.
- **Gas TSOs OGE and Ontras are exposed to material transported gas emissions, which they exclude from their Scope 3 reporting.**[63] Pressure to address these indirect emissions is likely to rise. The risk of declining gas demand could impact their cash flow generation. TSOs' earnings may come under pressure as risks related to lower utilisation rates and stranded assetslo may build over time, increasing reliance on the Federal Network Agency regulatory framework that sets remuneration methods for gas transmission activities. In response, OGE and Ontras plan to heavily invest in hydrogen networks to decarbonise emissions from gas transportation. The credit profiles of their new hydrogen network businesses would be supported by a distinct regulatory framework based on a cost-plus model, which aims to mitigate risks during the ramp-up phase. However, their future hydrogen network earnings would rely on a steady and continually supportive regulatory framework. The scalability of hydrogen remains uncertain and poses long-term financial risk.

[61] EnBW. Jointly owned power plant in Lippendorf: EnBW sells its shares to co-owner EP Energy Transition. 20 May 2025.
[62] EP Group owns LEAG and already held a 50% stake in Lippendorf before the May 2025 deal. EP Group also owns Energetický a průmyslový holding (EPH).
[63] IEEFA. Pipelines of uncertainty: The need for full emissions transparency in Europe's midstream gas. 22 December 2025.

Figure 11: German utilities' and gas TSOs' emissions targets



Sources: Company reports, IEEFA.

Notes: As RWE does not set absolute emissions targets, IEEFA estimated the utility's 2030 combined Scope 1 and 2 target from its emission intensity target. LEAG does not publish data on Scope 3 emissions. IEEFA included estimated transported emissions in OGE's Scope 3 emissions.[64] EnBW emissions include those from Ontras but exclude transported emissions.

New fossil fuel expansion could limit utilities' ability to invest in renewables

Germany's unregulated utilities are contemplating participating in the country's new gas-fired plant tenders. This would require additional capex, increasing debt leverage. The construction of new fossil fuel power plants — in addition to the already significant existing assets and those under construction — would increase carbon lock-in risks. If the plants remain unabated, this would be incompatible with these utilities' decarbonisation plans. Spending on new gas power plants could limit utilities' ability to invest in climate-aligned solutions. This adds uncertainty around utilities' earnings potential for deleveraging. Fossil fuel companies Uniper and LEAG could be more exposed:

- **Uniper remains committed to new gas power projects.** Recent expansions include a 300MW gas plant at the Irsching site. The company's capex on gas plants and hydrogen manufacturing is currently not aligned with the EU taxonomy's environmental criteria. While the company aims to align these investments with the taxonomy within five years, this is subject to significant execution risk, in IEEFA's view. Uniper exhibited weak operating performance and needed a government bailout in 2022. As the EU requires the German government to reduce its stake in Uniper, the company's access to new equity investors

[64] Ibid.

remains highly uncertain given its elevated standalone risk exposure. Energetický a průmyslový holding (EPH), which itself is predominantly fossil fuel-based, is among the companies that the government has approached about a purchase of Uniper.[65]

- **LEAG is part of a complex corporate group structure with an intention to expand fossil power.** The company was transferred from EPH to a sister company under the same parent, EP Group, in 2023. The transfer lowers clarity on disclosure and governance structures. Transition risk could continue to impact EPH's credit profile.[66]

On the other hand, RWE, EnBW and E.ON are at a more advanced stage of energy transition, as reflected in their relatively high EU taxonomy-aligned metrics (Figures 12 and 13). They are leading green bond issuers, which reflects access to sustainable investors. However, this does not eliminate the challenge of decarbonising their existing fossil fuel exposure. Further investment in fossil fuels will lower the coherence of their green bond programmes:

- **RWE, for instance, still spends significantly on coal and gas production.** This amounted to €511 million in 2024. The company has scaled back its renewable energy investments, lowering its 2025–2030 investment plan to €35 billion, a reduction of €10 billion compared with earlier plans.[67]

- **E.ON plans to develop a 61MW on-site gas power plant** for a data centre in Frankfurt.[68] Although this is a small project, any expansion from E.ON in this direction would signal a retreat from its renewable energy strategy. This would in turn undermine the credibility of its transition plan and the perception of the company as a renewables-driven green bond issuer. With its focus on electricity grids, E.ON has one of the most advanced transition plans among German utilities. This follows a spin-off of its fossil fuel assets into Uniper in 2016.

- **Uniper includes gas in its green bond framework.** The company is contemplating an inaugural green bond issuance, with a framework published in October 2025.[69] While utilities typically issue green bonds to fund renewable energy projects, Uniper's framework of eligible projects spans gas power, CCS, hydrogen, nuclear and renewables.

[65] Reuters. Exclusive: Kretinsky's EPH among those approached to buy Germany's Uniper, sources say. 20 January 2025.
[66] IEEFA. TotalEnergies and EPH launch joint venture centred on fossil fuels. 17 December 2025.
[67] RWE. RWE achieves strong earnings in 2024 and invests heavily in expanding its renewables portfolio. 20 March 2025.
[68] E.ON. CyrusOne and E.ON Announce Strategic Partnership to Overcome Data Center Grid Capacity Constraints for Customers in Europe. 2 June 2025.
[69] Uniper. Green Finance Framework October 2025.

Table 6: German utilities' and gas TSOs' ownership and capital structure

	RWE	EnBW	Uniper	LEAG	E.ON	OGE/ VGT	Ontras
State ownership	Nil	46.75% by the federal state of Baden-Wuerttemberg and 46.75% by an association of districts in Baden-Württemberg	99.12%[70] by German federal government	Nil	Nil	Nil	Indirect through EnBW
Other significant shareholders	Nil	Nil	Nil	EP Group	RWE (15%)	Infinity Investments, UAE (24.99%);[71] Fluxys (24.1%)	EnBW (100%)
Credit ratings	Baa2/BBB+	A-/Baa1	BBB-	Nil	BBB+/Baa2/ BBB+	BBB+	Nil
Sustainable finance	Green bonds	Green bonds	Sustainability-linked loan	Nil	Green bonds	Nil	Nil

Sources: Company reports, company websites [accessed on 11 February 2026], IEEFA.

[70] The European Commission state-aid approval requires the German government to reduce its shareholding to a maximum of 25% plus one share by 2028.
[71] In April 2025, Italian gas TSO Snam agreed to acquire 24.99% of Vier Gas Holding — which indirectly owns the entire share capital of OGE — from Infinity Investments. The deal was later terminated in November 2025 due to failure to secure regulatory approval.

Figure 12: German utilities' and gas TSOs' EU taxonomy-aligned revenues

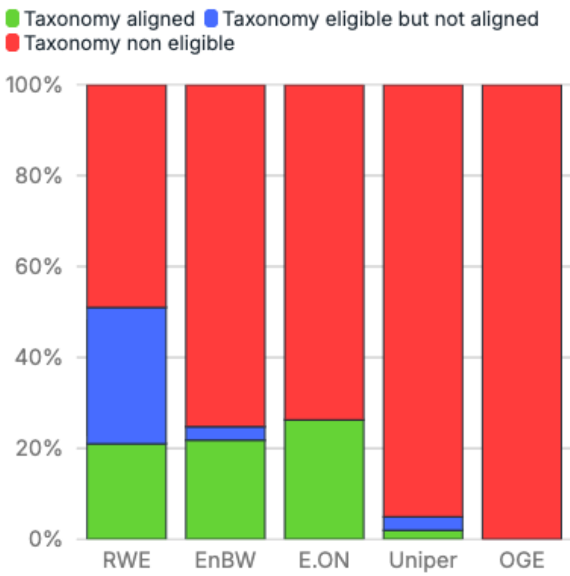
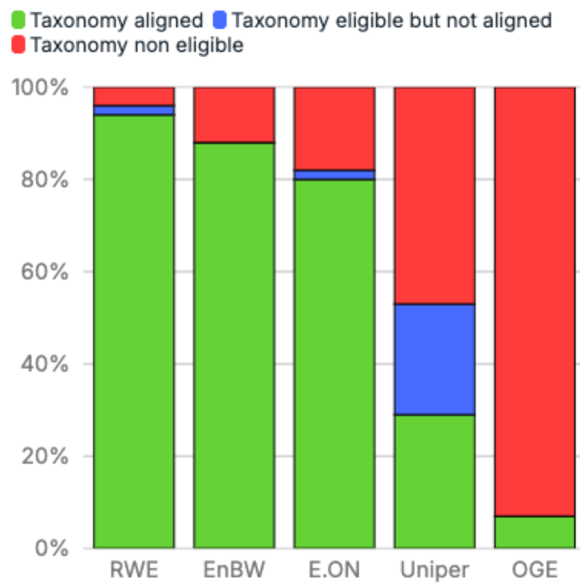


Figure 13: German utilities' and gas TSOs' EU taxonomy-aligned capex



Sources: Company reports.

Notes: LEAG does not report on its EU taxonomy alignment; it is likely that the alignment is zero. Ontras is reported under EnBW consolidated financials.

Government also bears transition risks and costs

Germany's nationalisation of Uniper in 2022 reflects the government's willingness to support the country's energy assets. While the EU requires Germany to reduce its Uniper ownership to a maximum of 25% plus on share by 2028 at the latest, the government could still be inclined to offer support in the event of future earnings volatility or losses arising from energy transition risks. In the case of EnBW, a €3.1 billion capital increase in 2025 underscores the strong backing from its public sector shareholders.[72]

The German government and state-owned development bank KfW have also directly invested in other fossil fuel infrastructure and projects, such as a €4.06 billion measure to support floating LNG terminals. German state-owned entities are developing the gas-fired capacity that the country will commission in the next three years (Figure 10); the state is also in discussions to support additional capacity.

[72] EnBW. EnBW successfully completes capital increase. 15 July 2025.

Table 7: Government support for German utilities and gas TSOs

	RWE	EnBW	Uniper	LEAG	OGE/VGT	Ontras
Coal phase-out subsidies	€2.6 billion			€1.75 billion		
New project funding commitments	€492 million for a 300MW electrolyser in Lower Saxony; €127 million for a hydrogen storage facility in North Rhine-Westphalia					
Equity injection		€3.1 billion equity raise in July 2025 subscribed by state shareholders	€13.5 billion injected in 2022 with repayment conditions (it repaid about €2.6 billion by March 2025)			
State-backed lending		€500 million non-recourse loan for the He Dreiht offshore wind farm	€5 billion revolving credit facility until September 2026[73]	Emergency credit facilities in 2022[74]	€24 billion credit line to the amortisation account of the country's hydrogen core network[75]	

Sources: Company reports and announcements, IEEFA.

Note: This is not an exhaustive list of all government support.

[73] Fully unutilised as of 2024. The line of credit was reduced from €16.5 billion as of February 2023 as part of stabilisation measures.
[74] Reuters. Germany's Leag secures credit facility from state lender KfW -sources. 14 March 2022.
[75] KfW. New milestone for the hydrogen strategy: KfW supports network development. 27 November 2024.

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

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