

International Energy Agency

Renewables 2026

Analysis and forecasts to 2031

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Abstract

Renewables 2026 is the IEA's main annual report on the sector, covering hydropower, solar, wind, geothermal, biofuels and biogases. It presents the latest forecasts and analysis, based on recent policy and market developments, while also exploring key challenges and opportunities facing the renewables sector.

This year's edition provides forecasts for the deployment of renewable energy technologies across electricity systems, transport, heating and biogases through 2031. It also examines the energy security implications of key trends, policy changes, the manufacturing of renewable technologies, and the financial health of different parts of the industry.

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Questions or comments? Please write to us at IEA-REMR@iea.org

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Executive summary

Increasing focus on energy security strengthens the case for renewables

Renewables have risen to the top of the policy agenda in many countries around the world as the current energy crisis underscores their role in strengthening energy security and diversifying supply. Disruptions to energy flows through the Strait of Hormuz stemming from the Middle East conflict have driven up oil and gas prices and increased market volatility. Because renewable resources are widely distributed, every country has domestic potential that can be developed competitively to strengthen energy security. Yet governments do not have to choose between security, affordability and sustainability. With well-designed policies, renewables can offer countries a way to diversify their energy mix, reduce exposure to imported fuels and high prices, lower overall electricity supply costs and cut emissions.

Renewables are already delivering major energy security benefits. Without their growth since 2010, global annual demand for fossil fuels would have been around 8% higher in 2025, an amount equivalent to India's total energy consumption. Renewables have also displaced natural gas consumption equivalent to 11% of global demand. This has lowered the influence of gas-fired power plants on wholesale electricity prices and helped limit price increases during the crisis in many countries. In addition, the growth of biofuels and other renewables since 2010 has displaced 2.4 million barrels of oil equivalent per day – comparable to Canada's total oil demand.

Renewable capacity growth accelerates, particularly in emerging and developing economies amid Hormuz crisis

Global renewable capacity is forecast to grow by almost 4 800 gigawatts (GW) in the 2026-2031 period, 57% more than in the previous six years, with growth in emerging and developing economies outside China matching that in advanced economies for the first time. In the forecast period, India becomes the world's second-largest growth market after China. Renewable capacity additions across Southeast Asia, the Middle East and Africa almost triple over the forecast period. Emerging and developing economies outside of China expanded at half the rate of advanced economies in the 2020-2025 period. New ambitions, energy security benefits, supportive policies and the growing competitiveness of wind and solar PV have raised the forecast for emerging and developing economies by almost 20% compared with our *Renewables* report a year ago.

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While policy support remains central to renewable electricity growth in developing economies, consumers are increasingly driving deployment as affordable solar PV helps households and businesses gain access to more reliable electricity. One of the most striking shifts during the recent energy crises has been in consumer behaviour. Faced with high fuel prices and unreliable grid electricity, households and small businesses are increasingly turning to affordable solar PV to improve the reliability of their electricity supply and help lower bills. Based on module trade data and other indicators, we estimate that additional rooftop solar capacity has improved electricity access and services for at least 70 million households since 2022. Off-grid solar PV capacity growth is expected to increase by 2.5 times to around 80 GW by 2031, led by Pakistan, sub-Saharan Africa and Southeast Asia.

Higher oil prices and energy security concerns amid the Middle East crisis have led us to lift the forecast for liquid biofuel production growth by 40% compared with last year's report. As an immediate response to higher fuel prices and availability challenges, many countries – especially in Southeast Asia and Latin America – are accelerating the implementation of new and previously announced liquid biofuel mandates to reduce reliance on imported fossil fuels. The impacts have been strongest in Southeast Asia, where biofuel consumption is set to grow by 11% between 2025 and 2026, well above the robust 7% average increase globally. Liquid biofuel demand worldwide is forecast to expand by nearly 30% by 2031, driven by energy security priorities, but robust sustainability frameworks are essential to ensure emission reductions without adverse land, water or biodiversity impacts. This includes frameworks that ensure transparent and verifiable greenhouse gas accounting and land-use and feedstock criteria.

Solar PV leads global renewable capacity expansion despite a slowdown in China

The world's total renewable electricity capacity is expected to increase by almost 85% between 2025 and 2031. Solar PV accounts for over three-quarters of this growth, while total onshore wind capacity increases by over 70% to 2 040 GW by 2031. China's share of global renewable capacity growth declines from over 60% in 2025 to 53% over the forecast period. India, Southeast Asia, Africa and the Middle East substantially increase their contributions to global renewable capacity growth due to strong policy support and renewable market development.

The downward forecast revision for China is more than offset by stronger outlooks for the United States, India, Southeast Asia, sub-Saharan Africa and Latin America. Outside of China, Asia Pacific adds more than 840 GW of renewables over the 2026-2031 period, more than double the level in the 2020-2025 period, with the forecast revised up by 15% on stronger solar PV

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growth in India and Southeast Asia. In the United States, we have revised our forecast higher by almost 40% from last year's report, mainly on stronger solar PV deployment, since solar PV and battery storage can be installed quickly to meet fast-growing electricity demand, including from data centres. The forecast for sub-Saharan Africa's renewable capacity expansion has been revised up by 54%, with solar PV accounting for over 80% of new capacity. Renewable power capacity in the Middle East and North Africa is expected to more than double in the forecast period. By the end of the decade, solar PV's installed electricity capacity in Latin America is set to overtake that of hydropower, becoming the largest in the region. While hydropower remains the region's largest source of electricity generation, its contribution declines from 40% in 2025 to 35% in 2031. Europe's growth continues to expand, with renewable capacity forecast to rise by 40% more in the six years through 2031 than it did in the 2020-2025 period.

China's shift from fixed tariffs to competitive auctions led to an almost 55% year-on-year decline in solar PV capacity additions in the first nine months of 2026. As a result, we have revised down our forecast for renewable capacity growth in China by 5%, or almost 116 GW, compared with last year's report. Nonetheless, our main case still sees China exceeding the new renewable capacity and generation targets announced under its 15th Five-Year Plan.

China's global dominance of solar PV supply chains persists amid high financial strains and mounting bankruptcies, while India is emerging as an important source of diversification. Over 90% of major Chinese solar PV manufacturers have reported losses in 2026, and more than 70 companies have filed for bankruptcy since 2024, as overcapacity and falling prices have eroded margins. Despite this industry turmoil, solar PV supply chains remain highly concentrated in China at every stage, from polysilicon to modules. However, by 2031, India is expected to be the only country besides China capable of manufacturing every major component of the solar PV supply chain at scale, contributing to supply chain diversification. Wind supply chains are more geographically diverse than solar PV today, but the competitive landscape is shifting as Chinese wind manufacturers expand rapidly into international markets.

Faster implementation of auctions, grids, storage and permitting reforms could make the COP28 target of tripling global renewable capacity achievable in 2031. In our main case, global renewable capacity reaches around 9 710 GW by 2030 – 2.6 times the 2022 level and short of the target of tripling by 2030. However, faster implementation of competitive auctions, timely and increased grid investment, the expansion of battery storage, and permitting reforms could significantly raise deployment in the accelerated case. In this case, renewable capacity growth over the forecast period is 20% higher, allowing the world to reach the tripling target in 2031.

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As wind and solar PV expand rapidly, system flexibility becomes key challenge and opportunity

Renewables are forecast to generate almost 45% of global electricity in 2031, up from 33% in 2025. Electricity generation from wind and solar PV combined more than doubles globally, reaching over 28% of total power generation by 2031. Electricity generation from solar PV has already surpassed that of wind and is set to overtake that of hydropower in 2029, becoming the world's largest source of renewable electricity.

Rising system integration challenges call for more flexibility. In 17 countries, the share of variable renewables in the power mix exceeds 50% by 2031, requiring stronger grids and interconnections, affordable storage, more dispatchable supply, and enhanced demand-side flexibility. Technical curtailment of wind and solar PV output in key markets almost doubled in both 2024 and 2025. It reached almost 200 terawatt-hours (TWh) in 2025 and could exceed 800 TWh by 2031, the equivalent of almost 8% of total variable renewable generation. At the same time, the number of hours of negative electricity prices continues to rise across Europe. Lower prices during periods of solar PV availability are reducing revenues for merchant projects and corporate power purchase agreements, testing the market-based deployment model that has expanded rapidly over the past decade. Battery storage deployment is accelerating in many countries and addressing some of these challenges, but not fast enough.

Hybrid projects combining solar PV, wind and batteries are emerging as an attractive option for increasing system flexibility. Hybrid systems combining solar PV and/or wind with batteries can already deliver electricity generation costs below USD 75 per megawatt-hour in many regions, with significantly greater dispatchability than standalone solar or wind projects. Increasingly supported through hybrid auctions and procurement schemes – mainly in India – these systems can reduce curtailment, improve asset utilisation and provide flexibility services cost-effectively under favourable market conditions. As battery costs continue to fall, hybrid systems are expected to play a growing role in the next phase of renewable expansion.

Falling battery costs are also driving rapid growth in consumer-led storage deployment. Behind-the-meter battery storage is expected to expand almost sixfold to over 670 gigawatt-hours by 2031, with more than one-third of home PV systems including a battery by that year. As storage becomes more affordable, households and businesses are using batteries to reduce their exposure to electricity price volatility. Where market and regulatory design, price signals and incentives are appropriate, behind-the-meter batteries can also help meet overall system flexibility needs.

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Grid connection queues are shifting towards storage and hybrid projects, while reforms are filtering out less viable projects. Global grid connection queues for advanced-stage renewable energy projects increased by 60% over the past year to 3 000 GW, with battery storage and hybrid renewable project applications accounting for the entire increase. Meanwhile, stricter connection rules and queue management reforms in India, the United Kingdom and the United States removed almost half of early-stage standalone wind and solar PV projects from queues, helping to prioritise more viable projects.

Electric vehicles and biofuels play complementary roles in expanding renewable energy use in transport

Renewable energy consumption in transport is forecast to increase by 60% in the forecast period in our main case, raising its share of global transport energy demand to 6%. Renewable electricity used by electric vehicles accounts for almost half of this growth, with China and Europe together contributing 80% of the increase in EV-related renewable electricity use. Liquid biofuels remain the second-largest driver of growth, supported by stronger mandates and rising transport fuel demand. Aviation and shipping become key new markets as governments introduce sustainable aviation fuel mandates and low-carbon fuel regulations and the industries seek to diversify fuel supplies. Biomethane, renewable hydrogen and e-fuels expand rapidly from a low base, providing further options for reducing emissions in hard-to-abate transport uses in the longer term.

Robust sustainability frameworks are essential to scale up liquid biofuel use. Global feedstock demand for liquid biofuel production is expected to increase by 30% by 2031, with oil-based feedstocks growing fastest as demand rises for biodiesel, renewable diesel and biojet fuel. Liquid biofuels offer significant lifecycle emissions reduction potential across all forms of transport, but sustainability underpins both current and future demand. For countries seeking to expand domestic production and capture growing export opportunities, developing and fully implementing transparent, robust and internationally agreed sustainability frameworks will be essential. At the same time, the possible impacts of current high fertiliser prices and extreme weather conditions, including El Niño, remain important factors affecting the forecast for biofuels.

Electrification becomes the dominant driver of renewable heat growth, putting heat-related emissions into decline

The share of modern renewables meeting demand for heating rises from 15% in 2025 to 19% in 2031, helping diversify energy supply and putting heat-related carbon dioxide emissions into decline for the first time. Energy security concerns continue to support the deployment of domestic renewable heat

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sources and reduce exposure to high fossil fuel prices and import dependence. Renewable electricity use for heat, through heat pumps and industrial electrification, increases by more than 50% over this period, providing around two-thirds of the growth in demand for modern renewable heat. The pace of electrification remains closely linked to energy prices and policy design, which can vary across countries, while also depending strongly on electricity taxes and levies compared to natural gas. Direct renewable heat from modern bioenergy, solar thermal and geothermal sources still accounts for the majority of modern renewable heat use (around 60% in 2025), but contributes only around one-quarter of growth through 2031.

Heat pumps and district energy offer the largest opportunities to accelerate the deployment of renewable heat. The increasing share of renewables in electricity generation and growing electrification are opening new opportunities for renewable heat in buildings and industry. District heating networks remain a largely untapped opportunity. Renewables supply just 7% of global district heat, despite networks' potential to integrate renewable and recoverable heat at scale.

Biomethane drives global biogases growth as new markets reach commercial scale

Global biogas production is forecast to grow by almost a fifth by 2031, entirely driven by biomethane, whose production nearly doubles amid expanding policy support and compatibility with existing gas infrastructure. As a result, biomethane's share of biogases production rises from 22% today to 35% in 2031. Europe remains the largest biomethane producer, followed by the United States, while large emerging and developing economies are scaling up supply from a small base. India's production is forecast to grow almost ninefold by 2031, and Brazil, China and India are developing robust policies to support uptake. Despite abundant technical potential from organic waste and residues, the development of commercial feedstock supply chains remains a challenge for unlocking faster growth.

Biogases are expanding beyond road transport, strengthening energy security and creating new low-emissions fuel opportunities. Road transport remains the largest biomethane market, but demand is growing rapidly in industry and buildings as procurement frameworks, certificate markets and regulations mature. Bio-LNG use in maritime shipping is emerging as an attractive option to comply with decarbonisation regulations, mainly in Europe. Domestic biogas and biomethane production is already reducing dependence on natural gas imports by 22 percentage points in Sweden, by 10 in Germany, and by 8 in France.

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Chapter 1. Renewable electricity

Summary

- Global renewable capacity additions are set to decline 11% to 733 GW in 2026. This expansion is still the second highest on record.
- Renewable power capacity worldwide expands over 4 770 GW over 2026-2031, with solar PV accounting for over three-quarters of growth. Global cumulative wind capacity increases 75% to reach nearly 2 250 GW by 2031.
- China is the largest market worldwide accounting for 53% of global renewable capacity growth over 2026-2031. India is the second-largest country, while the Association of Southeast Asian Nations (ASEAN), the Middle East and North Africa (MENA) and sub-Saharan Africa collectively triple their growth pace.
- Europe adds 617 GW of renewables over 2026-2031, almost 40% more than in 2020-2025, but annual additions plateau at around 103 GW. The share of renewables in the EU electricity mix exceeds 60% in 2030.
- Overall forecast growth remains broadly unchanged from last year. Deceleration in China is offset by stronger outlooks for ASEAN, India, the United States, sub-Saharan Africa and Latin America.
- In the main case, total renewable capacity reaches 2.6 times its 2022 level by 2030, falling short of the COP28 tripling goal. The accelerated case reaches 90% of the goal if countries address policy and implementation challenges.
- The share of renewables in global electricity generation reaches 43% by 2031, up from 33% in 2025. Wind and solar PV's combined share increases from 17% to 28%, while curtailment is projected to rise almost fivefold to 850 TWh.
- Hybrid solar PV-wind-battery systems can deliver electricity at a cost of less than USD 75/MWh in many regions, contributing to more flexible generation. Stricter delivery requirements raise costs by USD 30/MWh.
- Global grid connection queues rose to almost 4 500 GW in 2026, made up increasingly of storage and hybrid projects, even as reforms removed around 430 GW of speculative solar PV and wind projects.
- Renewable-technology manufacturing remains under pressure, with over 90% of major Chinese solar PV manufacturers reporting losses and more than 70 companies filing for bankruptcy since 2024.
- Behind-the-meter battery storage expands more than fivefold to almost 700 GWh by 2031, with residential battery additions rising from 13% to over 35% of rooftop solar PV additions globally.

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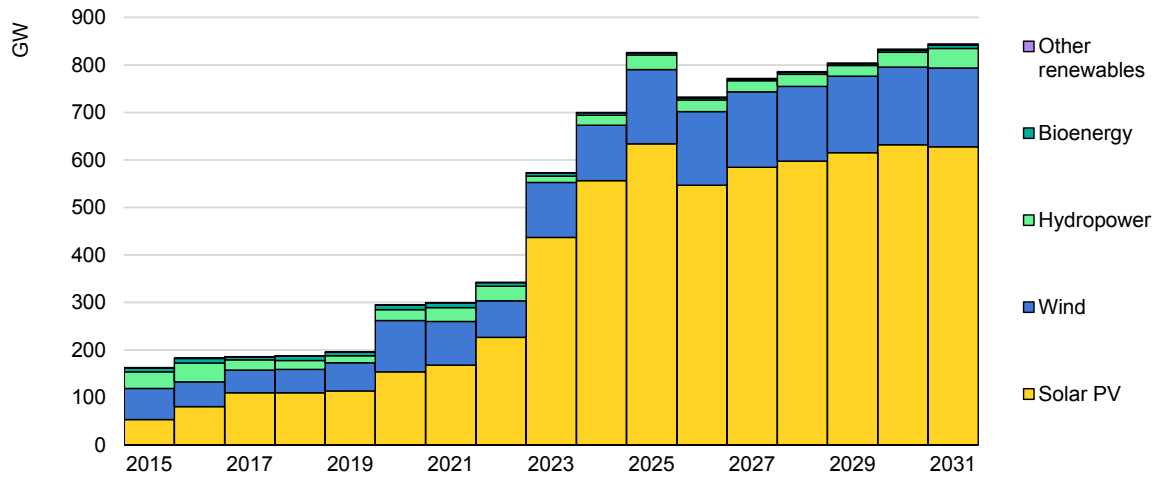
Global forecast summary

Following a decline in 2026, renewable capacity additions recover gradually as accelerating growth in emerging markets offsets China's slowdown, while advanced economies remain flat

Global renewable capacity additions are forecast to decline 11% in 2026, ending 21 consecutive years of record-breaking annual expansion, but are still at the second-highest level ever registered. This contraction results mainly from a deceleration in the People's Republic of China's (hereafter, "China") solar PV deployment, which has been the engine of global PV expansion, making up 60% of additions worldwide since 2023. Chinese solar PV additions were almost 55% lower in the first nine months of 2026 than in the same period in 2025, reflecting weakening project economics with the government shifting its support framework from fixed remuneration to competitive auctions in June 2025.

China's wind capacity additions are expected to slow in 2026, but much less sharply than solar PV, as the commissioning of large-scale projects partly cushions the impact of recent policy reforms. Faster wind deployment in Europe and the United States offsets China's slowdown, leaving global wind capacity additions broadly unchanged from 2025.

Renewable electricity net capacity additions by technology, main case



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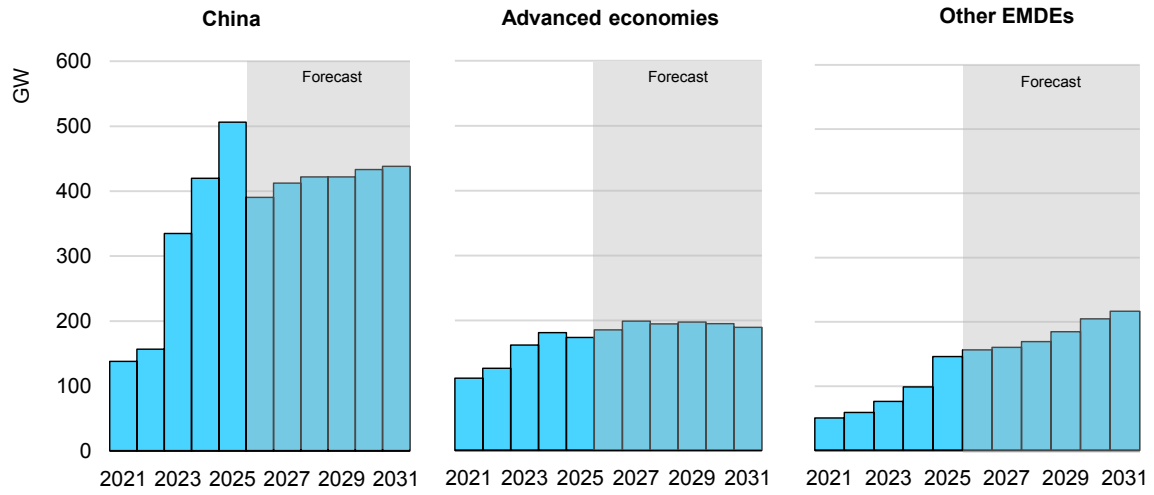
Notes: Solar PV capacity is in direct current (DC). "Other renewables" include geothermal energy, concentrated solar power and marine power.

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Global annual renewable capacity additions in 2026-2031 are expected to average almost 800 GW/yr in the main case forecast, 57% above the 2020-2025 average. Following the decline in 2026, China's annual capacity additions recover gradually, but remain 13% below the 2025 level in 2031. In July 2026, China released its 15th Five-Year Plan for Renewable Energy Development, setting an indicative cumulative target of at least 2 800 GW of wind and solar PV (AC) capacity by 2030. This implies around 190 GW of combined annual deployment of wind and solar PV (in alternating current [AC]) through 2030. Nevertheless, the main case expects China to exceed these policy targets by almost 30%, continuing its established trend of surpassing the ambitions of previous Five-Year Plans.

Outside of China, annual renewable capacity additions are forecast to increase 27% between 2025 and 2031, mainly in emerging markets and developing economies (EMDEs) as strong policy momentum and growing energy security concerns accelerate deployment. Led by solar PV, annual renewable capacity additions across India, the Association of Southeast Asian Nations (ASEAN), sub-Saharan Africa, Latin America, the Middle East and North Africa (MENA) and Eurasia are projected to match those of advanced economies over the forecast period for the first time.

Renewable electricity net capacity additions in China, advanced economies, and other emerging and developing economies, main case



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Note: EMDEs = emerging markets and developing economies.

India's robust growth continues to benefit from a decade of proactive policy support that has partly cushioned the electricity sector from the impacts of the energy crisis. In both the ASEAN and sub-Saharan African markets, dual drivers underpin growth: first, some governments introduced more ambitious renewable

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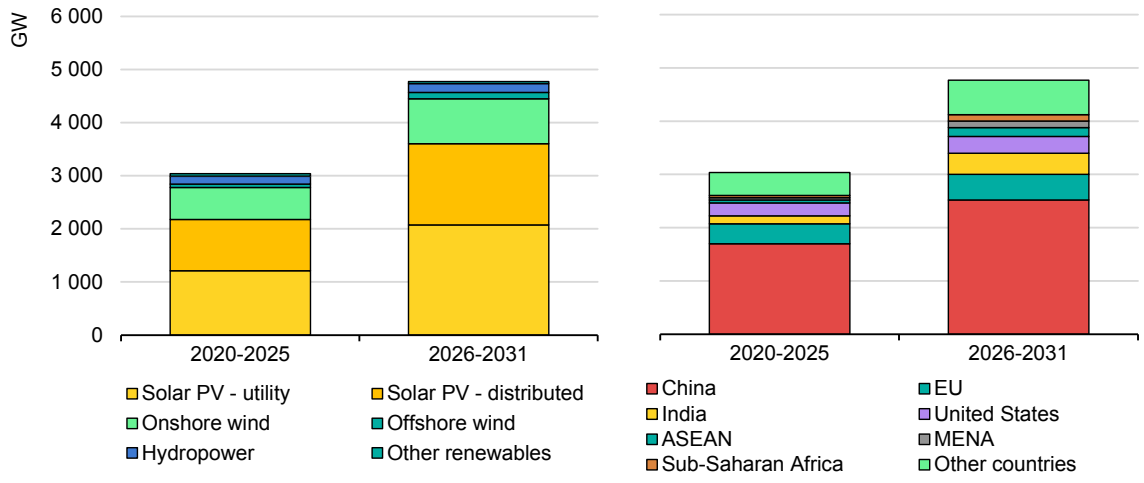
energy targets following the Middle East crisis; second, others adopted measures to accelerate the implementation of previously announced targets. In addition, consumers increasingly adopt decentralised rooftop solar PV systems to mitigate the impacts of daily load shedding and grid unreliability.

In advanced economies, renewable capacity additions plateau following strong acceleration since 2021 as grid integration, financing and permitting challenges mount. In Europe, annual renewable capacity additions are forecast to average around 100 GW over 2026-2031, remaining consistent with 2025. In the United States, average renewable capacity additions are slightly higher than the 2025 level to accommodate rapidly growing electricity demand, mainly from data centres. Meanwhile, Asia-Pacific annual capacity trends show gradual acceleration relative to 2025 – particularly in Korea and Japan – owing to a series of policy improvements and market reforms.

Solar PV continues to lead global capacity expansion through 2031 while China's historical dominance is expected to weaken

Renewable power capacity is projected to expand over 4 770 GW between 2026 and 2031, making up over 80% of total global power capacity additions. This expansion over the forecast period marks a 57% acceleration compared with 2020-2025.

Renewable electricity net capacity growth by technology and country/region, main case



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Notes: ASEAN = Association of Southeast Asian Nations. MENA = Middle East and North Africa. Solar PV capacity is in direct current (DC).

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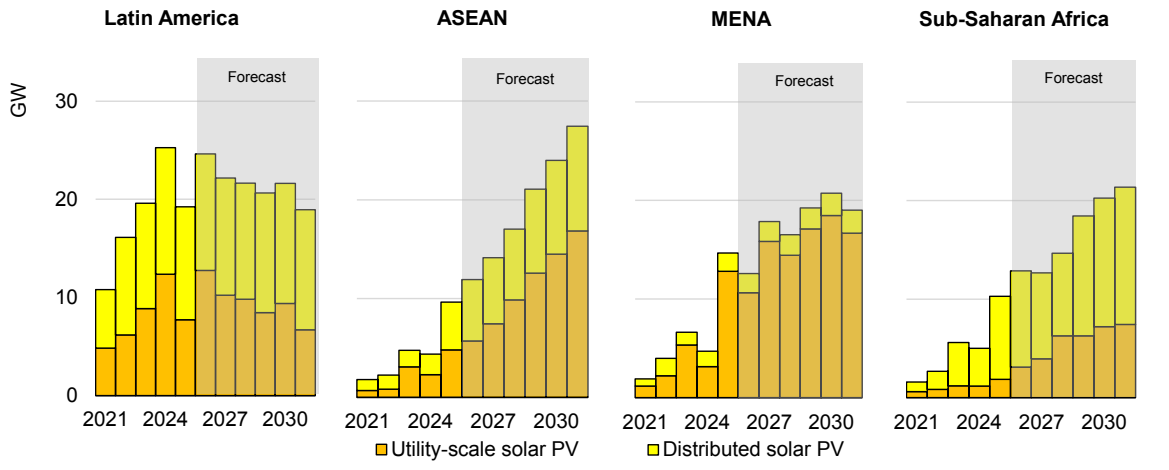
Solar PV remains the key growth driver, accounting for three-quarters of global renewable capacity expansion to 2031. Utility-scale solar PV capacity is forecast to expand 2 075 GW during 2026-2031, while distributed applications – residential, commercial, industrial and off-grid systems – are set to grow an additional 1 530 GW.

Low generation costs relative to other renewable and conventional technologies, combined with robust policy support, make solar PV economically attractive for developers, businesses and consumers alike. Furthermore, faster permitting and broader social acceptance have made solar PV the preferred technology for many utility-scale developers, even for situations in which alternatives such as onshore wind cost less. Distributed solar PV is also expanding rapidly as consumers across an increasing number of locations deploy self-consumption systems to reduce electricity bills and/or enhance electricity service reliability.

China's declining share of global renewable capacity growth is shifting market focus to India, the second-largest contributor to global expansion. China accounted for over 60% of global renewable capacity expansion in 2025; however, its share is projected to moderate to 53% over the forecast period. By contrast, India's renewable capacity expansion between 2026 and 2031 is expected to be 2.6 times greater than in the previous six-year period, almost doubling its contribution to global growth to nearly 8.5%.

ASEAN, MENA and sub-Saharan Africa are collectively tripling their pace of renewable capacity growth over the next six years, primarily installing solar PV systems. Driven by the rapid implementation of ambitious targets across many ASEAN countries following the recent energy crisis, the ASEAN region is projected to have the highest annual solar PV additions by 2031, surpassing Latin America, MENA and sub-Saharan Africa over the forecast period.

Solar PV net electricity capacity additions in Latin America, ASEAN, MENA and sub-Saharan Africa, main case, 2021-2031



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Notes: ASEAN = Association of Southeast Asian Nations. MENA = Middle East and North Africa. Solar PV capacity is in direct current (DC).

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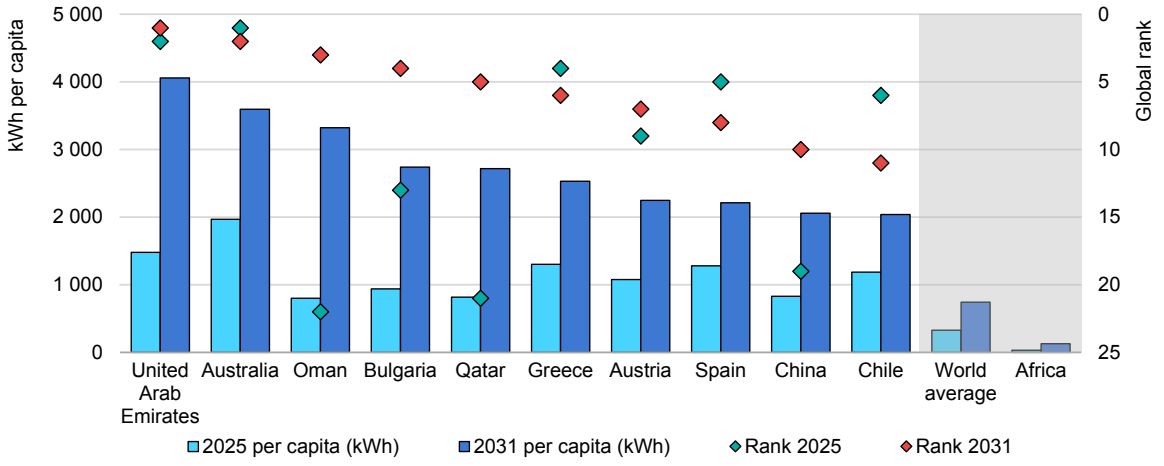
Annual renewable capacity additions in Latin America remain above historical levels despite declining from their 2026 peak, driven by slower growth in Brazil while Mexico, Chile and Colombia remain broadly stable. Meanwhile, in the MENA region, Saudi Arabia is set to accelerate its renewable expansion fivefold between 2026 and 2031, followed by the United Arab Emirates, marking a structural step-change in the region's energy market. In sub-Saharan Africa, growth remains led by South Africa and Nigeria, which account for almost half of the region's new capacity.

Global per-capita solar PV generation doubles and new leaders emerge, but disparities persist

Solar PV generation per capita is rising rapidly worldwide, but growth remains highly uneven across regions. Today's leaders include Australia, the United Arab Emirates, the Netherlands, Greece and Spain, which have all registered well above 1 200 kWh per person in recent years. Over the outlook period, however, the ranking shifts, with the United Arab Emirates becoming the largest generator of solar PV per capita worldwide, while Oman and Bulgaria surge into the top tier. China also moves into the top 10 as the top-10 entry threshold roughly doubles, reflecting the pace of deployment in fast-growing markets.

At the global level, average per-capita solar output is more than twice as high by 2031, but the leading countries still generate multiple times that average. This highlights persistent disparities in both deployment rates and access to solar generation.

Solar PV electricity generation per capita for the top 10 countries, 2025 and 2031



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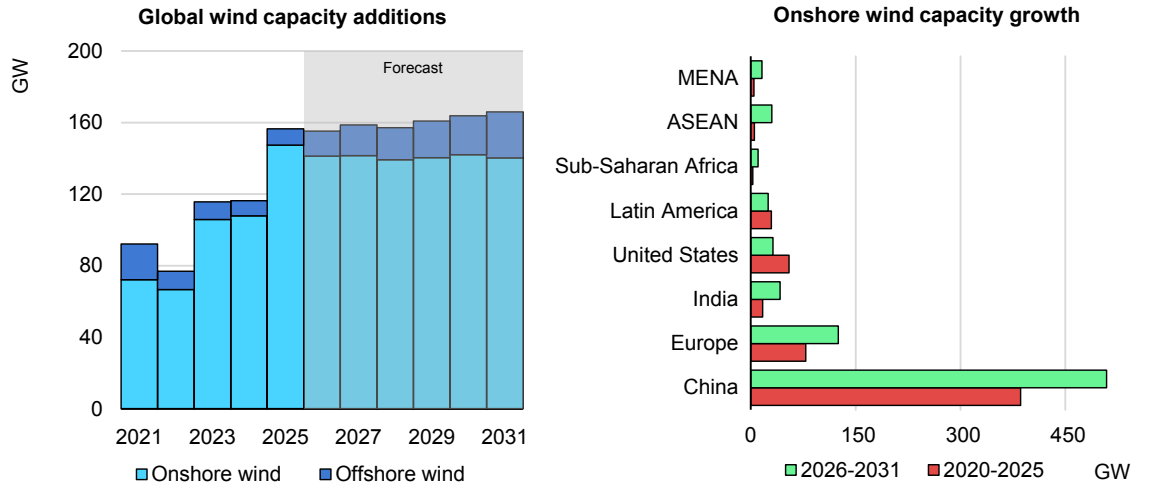
IEA. CC BY 4.0.

The most pronounced gap – and the largest strategic opportunity – remains in sub-Saharan Africa. Across the nine countries in the dataset (Nigeria, Ethiopia, Tanzania, South Africa, Kenya, Angola, Ghana, Senegal and Namibia), per-capita solar output starts at just tens of kilowatt hours and rises only modestly over the outlook period, remaining at only a small fraction of the global average and well below what leading countries achieve. Given the region's abundant solar resources, land availability, fast-growing population and low electrification base, this shortfall represents one of the largest untapped opportunities in the global energy transition, but investment, financing and grid infrastructure challenges must be addressed.

Onshore wind growth accelerates, but offshore remains constrained by high costs and project delays

Global cumulative onshore wind capacity is forecast to increase 1.7-fold to 2 040 GW in 2031, an acceleration of 40% from the previous six-year period. Global onshore wind additions surged 37% to almost 150 GW in 2025, driven by a pre-policy transition deployment rush in China and remain robust at around 140 GW annually despite the subsequent slowdown in the Chinese market. Permitting reforms and strong policy support in Europe, hybrid auction schemes in India, and new competitive tenders in ASEAN are accelerating onshore wind expansion compared to the previous six-year period. Growth is declining in the United States due to the phaseout of tax incentives, while rising curtailment in markets such as Brazil and Chile is adversely affecting project economics and slowing expansion in Latin America.

Wind capacity additions, and onshore wind growth by country/region, main case



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Notes: ASEAN = Association of Southeast Asian Nations. MENA = Middle East and North Africa.

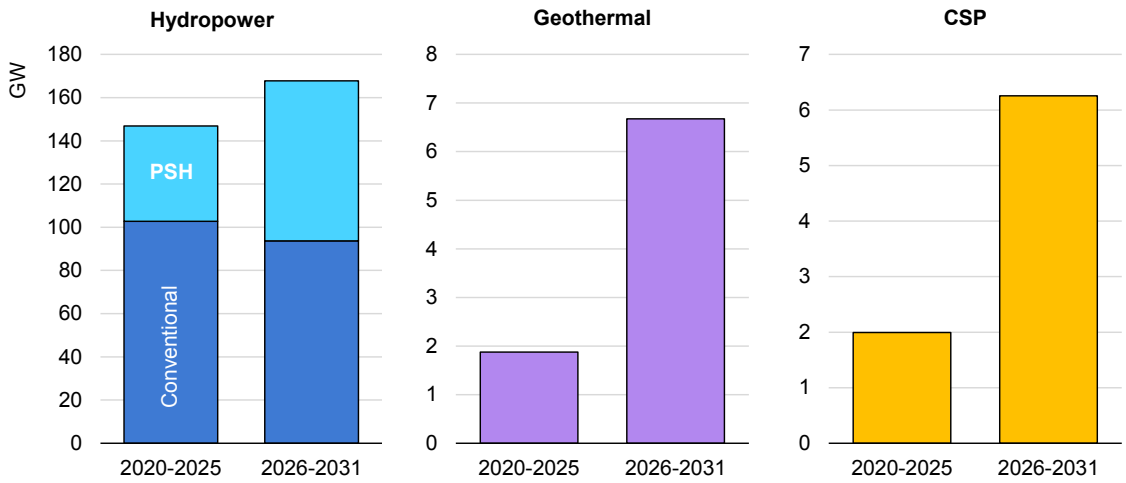
IEA. CC BY 4.0.

Offshore wind capacity expansion in 2026-2031 is forecast to almost double that of 2020-2025, with total additions of 117 GW expected. However, this growth trajectory remains 27% below last year's forecast, reflecting policy uncertainties, persistent supply chain bottlenecks and elevated financing costs. China is projected to account for 48% of total offshore wind additions through 2031, although its outlook has been revised downwards because project costs remain high and the business case has weakened following the transition to competitive auction mechanisms. In Europe, deployment accelerates to nearly 10 GW/yr by 2031, led by continued expansion in the United Kingdom. Outside of the United Kingdom, forecast levels have been reduced due to large-scale project cancellations and auction delays in the Netherlands, Germany and Belgium.

Pumped-storage hydropower gains momentum, while China accelerates concentrated solar power deployment

With wind and solar PV uptake expanding rapidly, an increasing number of countries are introducing policies to support dispatchable renewable energy technologies such as pumped-storage hydropower (PSH), geothermal systems and concentrated solar power (CSP) with storage. Deployment of these technologies is set to accelerate as a result, with PSH capacity growth nearly doubling over the forecast period compared to the previous six-year period and geothermal and CSP roughly tripling from a low base. While conventional hydropower growth slows slightly due to project delays and limitations on new large-scale developments, PSH is regaining momentum across many markets, reflecting its critical role in providing long-duration storage and facilitating the integration of variable renewables.

Hydropower, geothermal and CSP capacity growth, 2020-2025 and 2026-2031



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Notes: PSH = pumped-storage hydropower. CSP = concentrated solar power.

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Global PSH capacity expands by around 74 GW over 2026-2031, with China accounting for about two-thirds of additions as it scales up storage to integrate its rapidly growing wind and solar fleet. India follows at a distance, while several other markets – including Australia, Viet Nam, Indonesia and several European and Asian countries – contribute smaller but steady additions with the commissioning of multiple projects under development for more than a decade.

CSP deployment remains highly concentrated, with all growth occurring in China, supported by policy targets including a goal of around 15 GW of capacity by 2030 under the 15th Five-Year Plan for Renewable Energy Development. Overall, this rise aligns with China's policy support to increase long-term storage to integrate large-scale wind and solar PV capacity. **Geothermal capacity increases are more geographically diversified, led by the United States and Indonesia**, with continued expansion across established markets such as Japan, Türkiye, Kenya, New Zealand and the Philippines.

The global renewable capacity forecast remains broadly unchanged from last year, but this conceals significant regional shifts that offset each other

Globally, renewable electricity growth remains broadly in line with last year's forecast.[1] The small upward revision of 2%, or just 75 GW, reflects recent policy, regulatory and market developments since October 2025. China's forecast is reduced by the largest margin, nearly 116 GW. However, more positive outlooks in ASEAN, India, the United States, sub-Saharan Africa and Latin America offset the slowdown in China. The largest upward revision in percentage terms is for sub-Saharan Africa, where solar PV increasingly provides an alternative for millions of consumers to secure electricity service during rolling blackouts.

China: The downward revision stems from solar PV additions falling more than 50% year-on-year during January-September as the shift from fixed tariffs to competitive auctions eroded the profitability of utility-scale and distributed projects. Onshore wind, by contrast, held broadly at last year's record level and has been revised upwards, supported by policies favouring large-scale megabase projects and by capture prices almost 40% above solar PV's.

Upward revisions to hydropower and CSP reflect measures to ease system integration, including accelerated pumped-storage approvals and more ambitious CSP targets announced in December 2025. Offshore wind has been revised

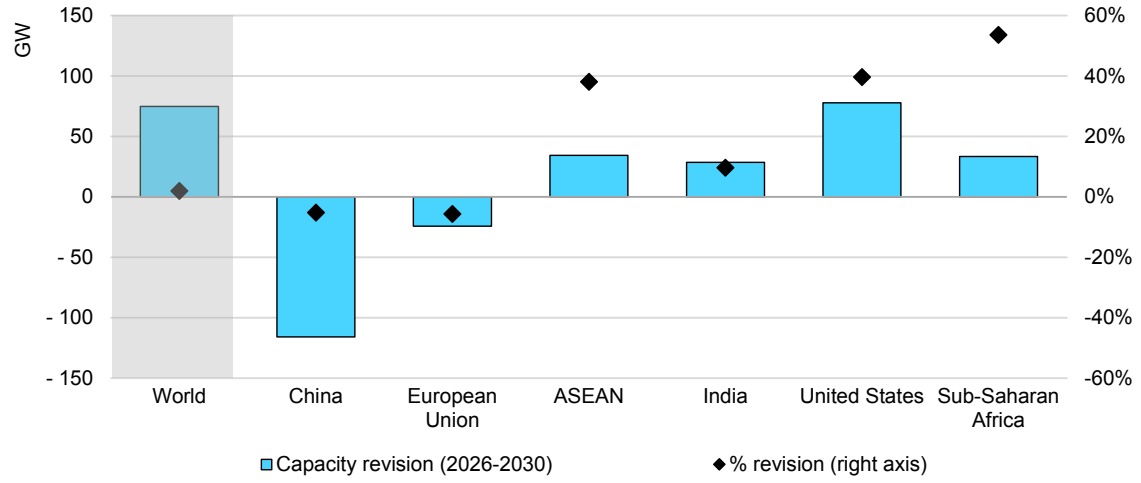
[1] The comparison of *Renewables 2025* and *Renewables 2026* forecasts covers renewable capacity growth from 2026 to 2030 (instead of 2031) because the *Renewables 2025* forecast period ended in 2030.

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downwards due to cost increases following the shift to competitive auctions and limited provincial-level support, while bioenergy uptake has slowed since 2024 amid weaker waste-to-energy growth.

European Union: Like last year, we are revising our forecast for distributed solar PV and offshore wind downwards, while utility-scale solar PV goes up to reflect higher auction volumes or award rates in Germany, Italy, Poland and France. The distributed solar PV outlook is revised downwards for all major EU markets due to a roll-back in support (i.e. the discontinuation of net metering in the Netherlands; EEG2027 feed-in tariff and net-billing cuts in Germany; lower subsidies and gross metering in Poland; and the phaseout of renovation rebates in Italy).

Renewable capacity expansion changes for selected countries/regions, *Renewables 2025* to *Renewables 2026*, 2026-2030



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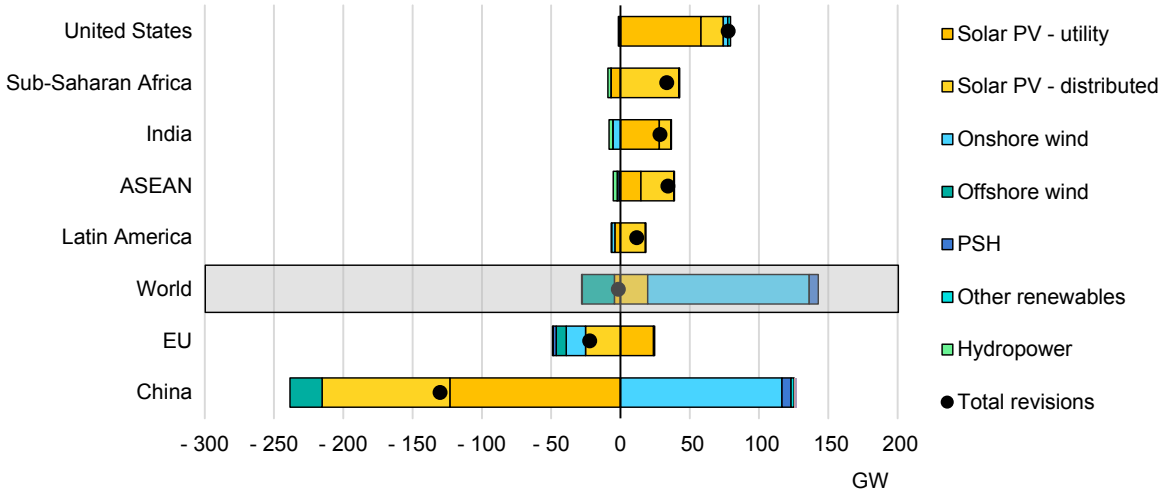
Note: ASEAN = Association of Southeast Asian Nations.

For offshore wind, forecasts have been revised down in Europe primarily because of failed or repeatedly delayed tenders in Germany, Denmark, Belgium and the Netherlands. For instance, Germany's August 2025 round drew zero bids; the Netherlands' 2025 Nederwiek I-A tender received no applications; and Belgium's contracts for difference (CfD) auction was deferred from Q4 2024 towards end-2026. However, several countries are revising their offshore wind auction designs to attract bidders. For instance, following Denmark's failed 3-GW tender in December 2024, the government redesigned the auction and awarded 1.8 GW across two sites, with bids of EUR 67.42/MWh and EUR 72.50/MWh. As both projects are expected to be commissioned beyond the forecast period, they are not included in this forecast.

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United States: The solar PV forecast has been revised 45% upwards because the pipeline is larger than expected for financed utility-scale projects qualifying for tax credits before the phaseout in 2027. Rapidly rising electricity demand from data centres further strengthens the outlook, as solar PV technologies can bring new generation online very quickly while supply-chain constraints continue to delay gas turbine availability. The federal court decision restoring the 5% cost-based safe harbour as an alternative to the physical work test provides a smaller additional boost, reopening a faster route for some wind and large solar projects to qualify for the 30% investment tax credit (ITC)/production tax credit (PTC) ahead of the 4 July deadline.

Renewable capacity expansion changes by selected country/region and technology, *Renewables 2025* to *Renewables 2026*, 2026-2030



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Notes: ASEAN = Association of Southeast Asian Nations. MENA = Middle East and North Africa. Solar PV capacity is in direct current (DC).

India: While the renewable capacity outlook has been revised upwards from last year, trends vary across technologies. Solar PV underpins stronger growth, supported by rapid recent deployment, a large pipeline of awarded projects and expanding uptake of rooftop systems backed by policy support. Pumped-storage hydropower is also gaining momentum thanks to more efficient administrative processes and an expanding project pipeline. In contrast, onshore wind is losing ground amid weaker deployment, limited auction volumes and increasing competition from solar PV paired with storage.

ASEAN: Across the upward-revised ASEAN markets, distributed solar PV leads growth, followed by utility-scale, owing to improved market access (through direct and virtual power purchase agreements (PPAs), and clearer PPA frameworks); new or expanded support schemes (net-billing FiTs, and higher net-metering caps and rooftop quotas); and strong auction results and subscriptions. Robust

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commercial and industrial projects and data centre demand reinforce the trend. In addition, the forecast for off-grid solar PV has been revised upwards because consumers are increasingly installing rooftop solar systems outside of policy schemes to improve their electricity service.

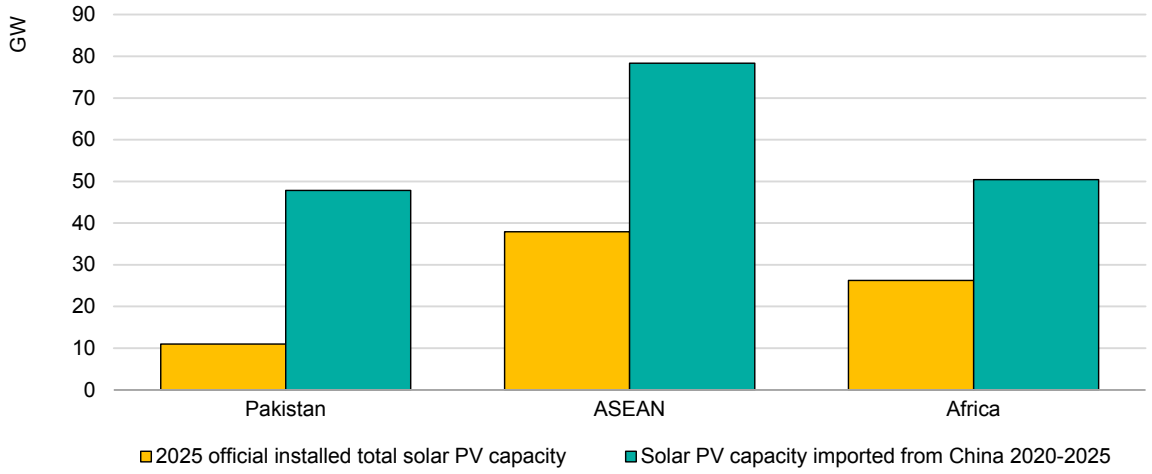
Sub-Saharan Africa: A 42-GW rise in distributed PV uptake over the forecast period, including rooftop and off-grid systems, has boosted the total solar forecast upwards by nearly 36 GW, while utility-scale was downgraded by nearly 7 GW due to a lack of financing and grid infrastructure challenges. Based on recent trade data, the largest forecast revision is for off-grid solar PV systems.

Middle East and North Africa: The forecast remains broadly unchanged, as stronger corporate demand, project expansions and higher targets offset slower renewable hydrogen development and project delays linked to the Strait of Hormuz closure.

"Missing PV panels" improve electricity access for at least 70 million households in developing countries

In the official statistics of many developing countries, there is a significant disconnect between installed solar PV capacity and volumes of panels imported from China. We refer to this difference as the "missing PV panels". The scale of this gap indicates that consumers in regions with limited electricity access – or facing daily blackouts of 8-10 hours – are increasingly installing small rooftop or garden systems to improve their electricity service.

Official cumulative installed capacity vs solar PV imports from China in Pakistan, ASEAN and Africa



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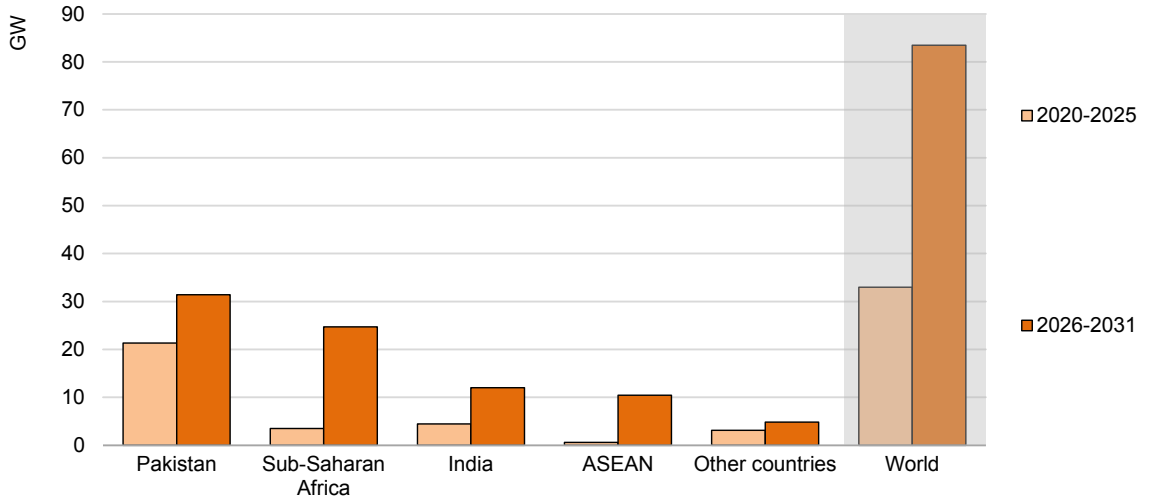
Note: ASEAN = Association of Southeast Asian Nations.

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Because these systems are typically not connected to the grid, they are difficult for governments to track and are therefore classified in our dataset as off-grid solar PV. In this year's analysis, we use trade data along with inventory estimates to account for additional installed solar PV capacity not covered by official statistics to serve households and industries in developing countries across Africa and Asia.

Pakistan's official statistics report only around 10 GW of installed solar PV capacity as of March 2026, but also nearly 50 GW of imports from 2020 to 2025. Although Pakistan exhibits the largest gap compared with Africa and the ASEAN, many developing economies with limited electricity access register a discrepancy of over 50%. Following the current conflict in the Middle East, African and ASEAN imports from China rose drastically in March, April and May, underscoring growing reliance on decentralised solar solutions.

Solar PV off-grid capacity forecast by country/region



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Note: ASEAN = Association of Southeast Asian Nations.

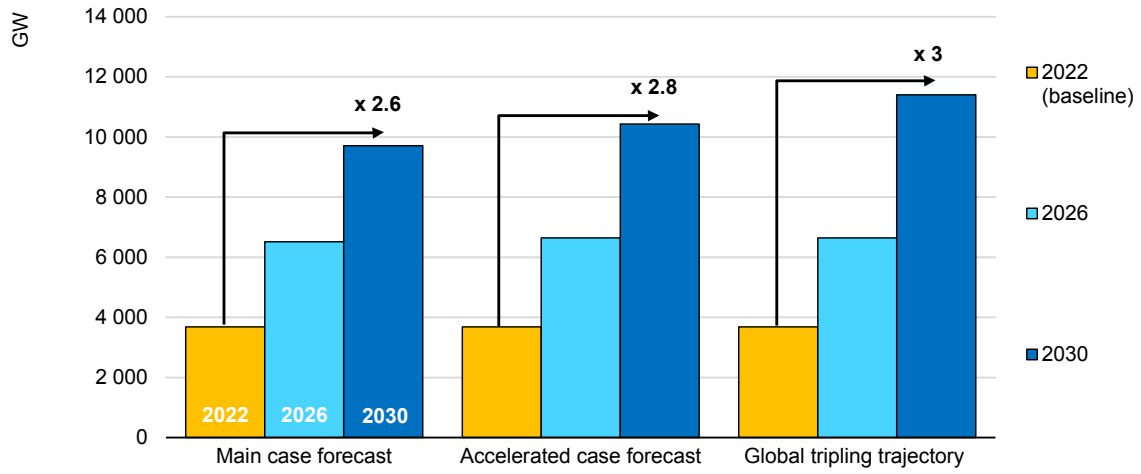
This trend leads to a significant off-grid solar PV expansion in our forecast. The pace of growth for 2026-2031 is projected to increase 2.5-fold from 2020-2025, with almost 80 GW of off-grid capacity to be installed through 2031. Outside of Pakistan's dynamic off-grid market, Sub-Saharan Africa is set to lead this surge, with more than 21 GW of new installations over 2026-2031 – equivalent to the region's total installed capacity today. In ASEAN, where consumers in countries most affected by the recent energy crisis are turning to off-grid systems to reduce their bills, about 10 GW of additional off-grid capacity is to be installed – a tenfold increase from current capacity of less than 1 GW.

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Strong renewable capacity expansion still falls short of the global tripling target

In 2023, nearly 200 countries at COP28 pledged to align with the Paris Agreement's 1.5°C goal, including an objective to triple global renewable energy capacity by 2030. **In the main case, current policies, market developments and cost trends boost cumulative renewable energy capacity to around 9 710 GW by 2030, a 2.6-fold increase from 2022**, in line with last year's forecast**.** While this growth marks significant progress, it remains below the level required to meet the tripling target.

Cumulative global renewable energy capacity, 2022, 2026 and 2030



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Based on this trajectory, the world would reach the tripling milestone only around 2032, highlighting persistent ambition and implementation gaps. In the accelerated case, renewable capacity growth is around 20% higher by 2030, bringing the world to 90% of the COP28 goal (or a 2.8-fold increase from 2022) and enabling it to reach the tripling target in 2031. The accelerated case assumes that governments rapidly address key challenges related to policy design, grid integration, permitting and financing, allowing substantially faster deployment and bringing the target within reach.

Six policy priorities to unlock accelerated-case growth

1. Expand and improve auction and revenue-stabilisation schemes

Comprehensive, predictable procurement programmes are the most common requirement in all accelerated cases. Many countries would need higher auction volumes, more regular auction schedules and improved contract designs, for instance including price indexation, to increase revenue certainty and expand the

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pipeline of bankable projects. This implies the wider use of CfDs, long-term procurement frameworks and support mechanisms that better reflect market conditions, particularly for technologies facing increasing merchant-price exposure. In countries such as Denmark, India, the Philippines, Romania, South Africa and the United Kingdom, more effective auction frameworks and support schemes could unlock additional accelerated-case growth by increasing the share of awarded projects reaching financial close and moving into the construction phase.

2. Accelerate grid infrastructure development and connection reforms

Grid constraints emerge as one of the most important barriers in most accelerated cases. Faster construction of transmission and distribution infrastructure, shorter connection timelines, queue management reforms and better grid planning are necessary to enable more solar PV and wind projects to be connected and operated. Such measures could unlock additional growth in the accelerated case, particularly in Australia, Brazil, Canada, Germany, India, the Netherlands, Serbia, South Africa, the United Kingdom and the United States. Without faster network expansion, increased renewable energy deployment could mean greater curtailment, longer delays and weaker project economics.

3. Scale up storage capacity and system flexibility

As renewable energy penetration rises, storage and system flexibility become increasingly important in the accelerated case. Many countries identify batteries, pumped-storage hydropower, long-duration storage, demand response and flexible electricity consumption as critical enablers to manage system integration, reduce curtailment and improve capture prices. Stronger policy support for storage and flexibility could therefore unlock additional renewable energy growth in the accelerated case, particularly in Australia, Chile, China, India, Italy, Spain and several European markets.

4. Streamline permitting and project approval processes

Accelerating deployment also requires better project delivery, not just larger project pipelines. Many countries have already introduced permitting reforms, but faster implementation, shorter approval times, and renewable-acceleration areas or one-stop-shop processes are needed. Faster permitting is especially important for onshore wind, utility-scale solar PV and transmission projects, as administrative procedures continue to delay deployment. In the accelerated case, taking these measures could unlock additional renewable capacity growth, particularly in Finland, France, Greece, Italy, Korea, the Philippines, Poland and Viet Nam.

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5. Strengthen corporate procurement and market-based demand

As support schemes evolve and electricity demand from data centres and other large consumers grows, further expansion of corporate PPAs and direct procurement mechanisms could support accelerated deployment. Stronger corporate procurement frameworks can improve bankability, reduce reliance on government support and provide long-term demand signals for renewable investment. The accelerated case therefore assumes greater use of these mechanisms, particularly in Canada, Italy, Japan, Korea, Spain, the United States and Viet Nam.

6. Support distributed solar PV and consumer participation

Several countries require stronger uptake of rooftop solar PV, energy communities, self-consumption and behind-the-meter storage. Policy measures include investment support, more attractive self-consumption frameworks, smart meters and greater exposure to more granular price signals, simplified connection procedures and better access to financing. Taken together, these measures could unlock the additional distributed solar PV growth envisaged in the accelerated case, particularly in Australia, Brazil, India, Italy, Mexico, Nigeria, Pakistan and Poland.

Accelerated-case assumptions for selected countries/regions

China: Renewable capacity additions could be around 13% higher than in the main case, with the largest upside gains coming from solar PV, followed by onshore wind, pumped-storage hydropower and offshore wind. Realising this potential would depend on several conditions:

1) higher auction volumes, as CfD auctions have so far been implemented in only some provinces (awarding around 200 GW of wind and solar), and nationwide roll-out in 2027-2028 – together with eased CfD contract constraints – to boost deployment and improve revenue certainty

2) faster power market reform, including cross-provincial green-certificate trading and expanded interprovincial power exchanges to strengthen project economics

3) quicker battery adoption, which would raise the value of wind and solar PV and improve capture prices

4) accelerated grid expansion to connect more capacity

5) corporate PPA market growth, building on recent reforms allowing large industrial users to sign direct PPAs

6) faster hydropower delivery, particularly of large pumped-storage projects.

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European Union: Renewable energy growth could be around 30% higher in the accelerated case with solar PV consistently offering the largest upside gains, followed by onshore wind. Realising this additional potential depends on a common set of enabling conditions:

1) faster grid expansion to relieve congestion and curtailment, and grid connection reforms to deliver shorter, more predictable connection timelines

2) quicker deployment of storage and system flexibility to absorb surplus renewable generation and protect project revenues

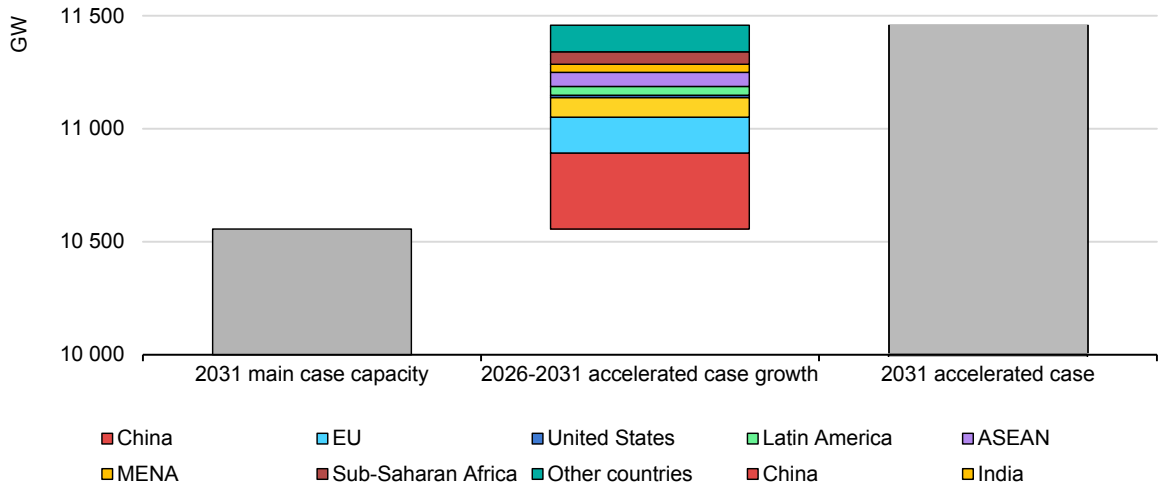
3) shorter permitting wait times, thanks to timely implementation of the EU Renewable Energy Directive (RED) III renewable-acceleration areas and one-stop-shop procedures

4) stronger revenue certainty for developers, achieved through sustained, well-designed auctions

5) more bankable corporate PPAs and faster electrification to strengthen demand for renewable electricity, or targeted support for distributed PV such as self-consumption incentives and energy communities

6) relaunching of rapidly cancelled offshore wind auctions, and faster enactment of postponed tender processes.

Cumulative renewable energy capacity and growth, main case vs accelerated case



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Notes: ASEAN = Association of Southeast Asian Nations. MENA = Middle East and North Africa. Solar PV capacity is in direct current (DC).

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India: Renewable capacity additions could be around 22% higher than in the main case, with the largest upside gains from utility-scale solar PV, followed by distributed solar PV, onshore wind and pumped-storage hydropower. Realising this would depend on:

1) higher and more regular auction volumes, since awards slowed considerably in 2025 and early 2026 after record allocations in 2024
2) steady procurement and faster PPA signing for awarded projects to enlarge the pipeline
3) improved distribution company (DISCOM) financial health, which would reduce perceived offtaker risk, lower financing costs and accelerate PPA signing while supporting rooftop and grid investment
4) faster battery adoption and grid expansion to raise system flexibility, ease integration challenges and cut connection delays
5) fewer barriers for open-access consumers, and streamlined approvals and optimised charges to speed commercial and industrial procurement
6) shorter permitting and construction timelines to accelerate hydropower delivery, particularly pumped storage
7) stronger support for residential rooftop PV, including through sustained subsidies, consumer awareness-raising campaigns, accessible financing and simpler grid-connection procedures.

ASEAN: Given the countries' prospects, renewable capacity growth could be 37% higher than in the main case. The strongest impact would come from rapidly finalising and implementing new market-access mechanisms for renewables (direct and virtual PPAs and third-party grid access that lets private buyers contract renewables outside of the single-buyer model in Thailand; and rules for direct PPAs in Viet Nam). The next orders of business would be to confirm and expand support schemes, such as distributed-PV quotas in Indonesia; to launch the 500-MW residential net-billing round in Thailand; and to obtain final approval and funding for the household rooftop scheme in Viet Nam.

Grid infrastructure expansion also remains critical for faster renewable energy deployment in ASEAN, relying on the approval of new transmission financing in Indonesia and stronger grid investment under Viet Nam's Eighth National Power Development Plan (PDP8). In addition, faster permitting and project implementation in the Philippines could contribute to the realisation of accelerated-case potential. Overall, electricity demand growth stemming from data centres and

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industrial electrification would also facilitate renewable capacity deployment, while enhancing the operational flexibility of existing coal fleets would help integrate higher shares of variable renewables.

Sub-Saharan Africa: Across sub-Saharan Africa, realising accelerated-case upside potential will primarily require faster grid and transmission build-out, as grid infrastructure remains the key bottleneck to implementation of the utility-scale project pipeline in multiple markets. South Africa's accelerated case hinges on the successful and timely delivery of its current grid expansion programme, while Nigeria's assumes that grid constraints and financing or bankability barriers are resolved, allowing the full utility-scale PV pipeline to come online.

A second, closely related lever is the conversion of project pipelines into actual capacity through effective procurement and policy delivery: in South Africa, this entails awards and announcements under Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) Bid Window 8 (covering both solar and wind), along with the successful commissioning of NERSA-registered private and embedded generation projects. Finally, significant distributed-solar upside potential could be realised through continued growth in residential deployment, supported by sustained consumer adoption, which has accelerated recently.

Middle East and North Africa: In the accelerated case, renewable energy expansion could be almost 30% higher – reaching nearly 233 GW by 2031 – if key regulatory, grid and financing barriers are addressed. As renewable penetration rises, system integration becomes increasingly important. Delivering investments in interconnections, batteries and pumped storage plans on or ahead of schedule could accelerate progress in realising existing renewable energy targets. Distributed solar PV could also expand more quickly if tariff and remuneration frameworks balance attractive economics for self-consumers with adequate grid cost recovery, alongside lower electricity subsidies.

Renewables make up nearly 45% of global electricity generation by 2031 as solar PV and wind reshape power systems

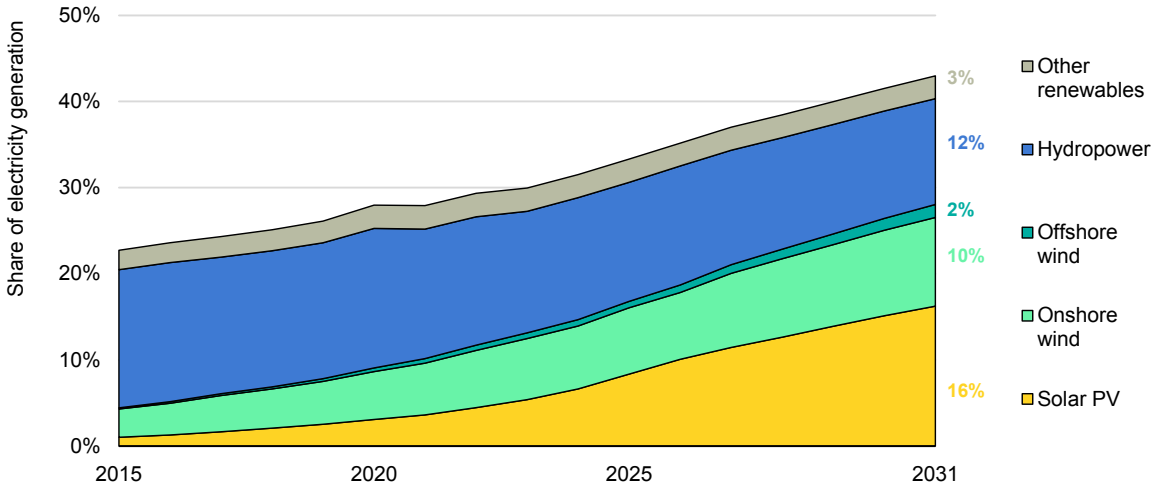
The share of renewables in global electricity generation is projected to expand from 33% in 2025 to 43% by 2031, primarily through rapid solar PV and wind expansion. Over the same period, wind and solar PV together account for over 80% of global electricity generation growth.

Rapid solar PV and wind deployment is reshaping the global renewable generation mix. Variable renewables overtook hydropower for the first time in 2024 and accounted for around 17% of global electricity generation in 2025, compared with hydropower’s 14%. By 2031, solar PV alone is expected to surpass

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hydropower, making up 16% of global generation, while wind generation rises to around 12%, broadly matching the hydropower contribution.

Global renewable electricity generation shares by technology, 2015-2031



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Note: Forecast renewable generation includes technical curtailment assumptions, based on available public data and historical yearly and monthly trends.
Source: IEA (forthcoming), Electricity 2027.

Renewable energy trends vary considerably across regions. **In China, renewables are set to provide nearly half of electricity generation by 2031**, up from 37% in 2025, with variable renewable energy (VRE) contributing to more than one-third. Although hydropower remains an important energy source, its share declines from 13% to 11% and it is overtaken by rises in both solar PV (from 11% to 20%) and wind (11% to 15%) during the forecast period, making solar PV the country's largest single renewable energy source.

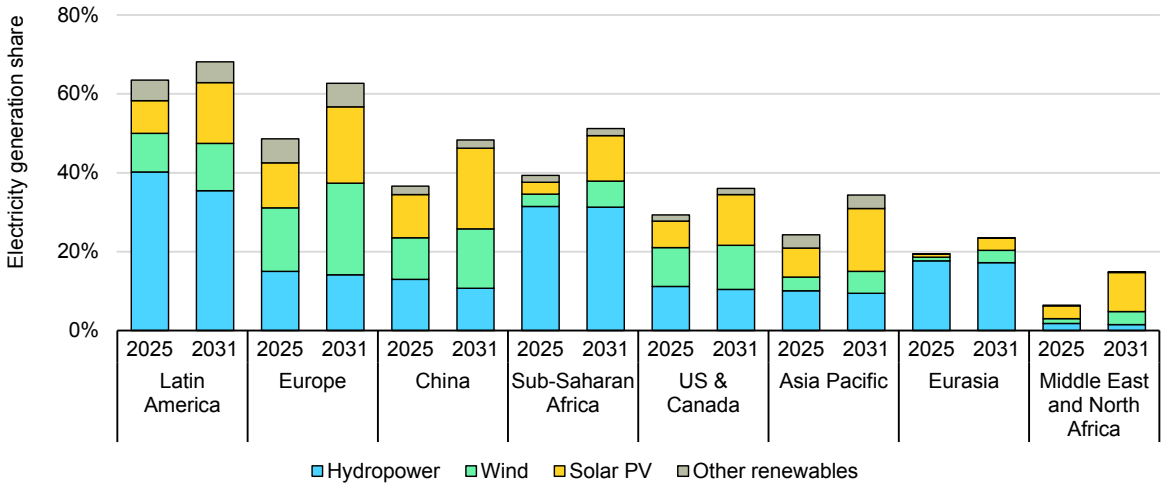
At these levels, China is expected to exceed its 15th Five-Year-Plan targets for non-fossil electricity generation and variable renewable generation in the power mix. **In the United States, the renewable share increases from 24% to 32%**, with solar PV nearly doubling from 8% to 14% and overtaking wind (11%) by 2031.

In Latin America, hydropower remains the dominant renewable energy source, although its share decreases from 40% to 35% by 2031. Nevertheless, the region maintains the world's highest renewable share at 68%, while solar PV becomes the main growth segment, expanding from 8% to 15% of generation to overtake wind.

In Asia Pacific excluding China, the renewable share rises from 24% to 34% by 2031. Solar PV makes up most of the increase, with its share doubling from 7% to 16% to surpass hydropower and become the region's largest renewable generation source, led by strong growth in India.

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Shares of renewable energy technologies in power generation by region, 2025-2031



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Source: Total electricity generation is from IEA (forthcoming), Electricity 2027.

Europe retains the highest VRE penetration among major regions, as wind and solar PV together increase from 27% to 43% of generation by 2031. Both technologies individually exceed hydropower, with wind making up 23% of generation and solar PV 19%.

In sub-Saharan Africa, hydropower remains the largest renewable generation source, accounting for almost one-third of electricity supply in 2031. At the same time, solar PV and wind shares more than double from around 3% today to 11% for solar PV and 7% for wind.

Renewable generation also expands in the Middle East and North Africa, where the renewable share increases from 6% to 15%, led by solar PV. In Eurasia, the use of renewables rises more modestly from 19% to 23%, with hydropower remaining dominant at around 17% of electricity generation.

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Regional forecast summaries

Key points

- China remains the largest growth market, adding almost 2 520 GW by 2031, but its share in global renewable capacity additions falls from 61% in 2025 to just around 53% over the forecast period as solar PV deployment moderates following policy reforms.
- In Asia Pacific (excluding China), renewable capacity additions in 2026-2031 are more than double those of 2020-2025, with India and ASEAN registering the most growth and solar PV dominating regional expansion.
- India becomes the second-largest growth market globally, with renewable capacity increasing 2.6 times faster than in 2020-2025 and its share of global expansion nearly doubling to nearly 9%.
- In the European Union, the main case forecast falls short of the REPowerEU ambition, with the renewable electricity share reaching 60% in 2030 instead of the 69% that could be achieved with timelier grid investment, storage deployment and permitting reforms.
- In Latin America, solar PV overtakes hydropower as the region's main capacity-growth component, while grid constraints and curtailment increasingly shape deployment patterns.
- MENA renewable capacity is forecast to more than double to almost 200 GW by 2031. The outlook remains stable as energy security and corporate demand offset weaker renewable hydrogen prospects and supply-chain delays.
- Sub-Saharan Africa adds over 120 GW of renewable capacity in 2026-2031, led by consumer-driven distributed solar PV, but grid and financing constraints continue to limit utility-scale growth.

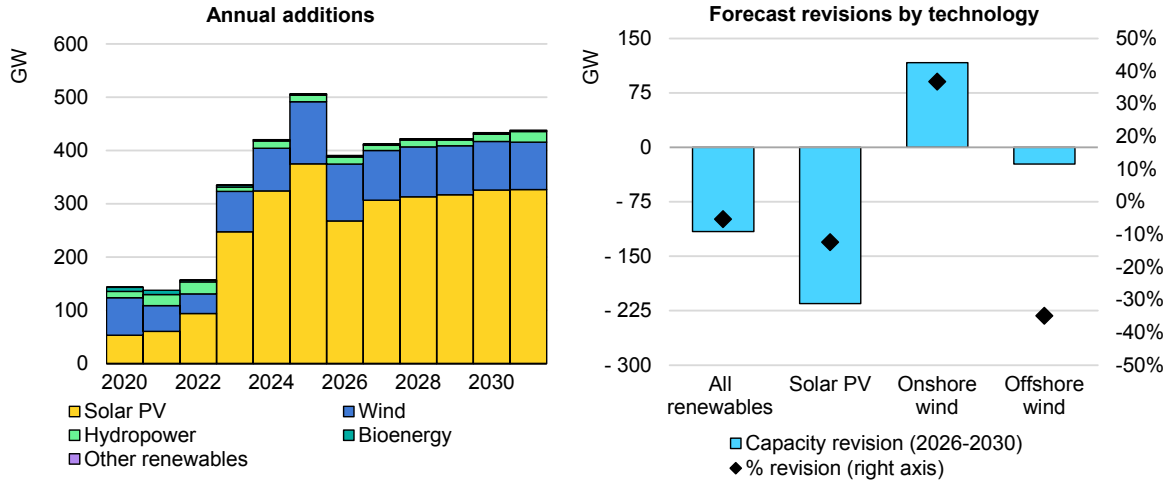
China

The renewable capacity forecast has been revised down from last year as slowing solar PV growth outweighs upward revisions to onshore wind, hydropower and concentrated solar power

China remains the world's largest renewable energy growth market by a wide margin, with capacity expected to expand almost 2 520 GW over 2026-2031, almost 50% more than in 2020-2025. Solar PV continues to dominate, accounting for roughly three-quarters of additions, followed by wind, while hydropower and other technologies make smaller contributions.

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China renewable electricity forecast summary



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Note: Solar PV capacity is in direct current (DC).

China's overall renewable capacity forecast has been revised down from last year, but this masks diverging trends across technologies. Solar PV, offshore wind and bioenergy expectations are lower: solar PV growth is slowing markedly as the transition from fixed tariffs to competitive auctions and greater exposure to wholesale markets weaken project profitability, while offshore wind is affected by cost pressures under the new auction framework. Bioenergy deployment has also eased along with slower waste-to-energy uptake.

In contrast, we have revised our forecasts for onshore wind, PSH and CSP upwards. Onshore wind is proving more resilient than expected, supported by stronger market revenues and a policy shift towards large-scale wind bases. PSH and CSP benefit from increased policy focus on system integration and long-duration storage, including faster approvals for pumped storage, and more ambitious CSP targets.

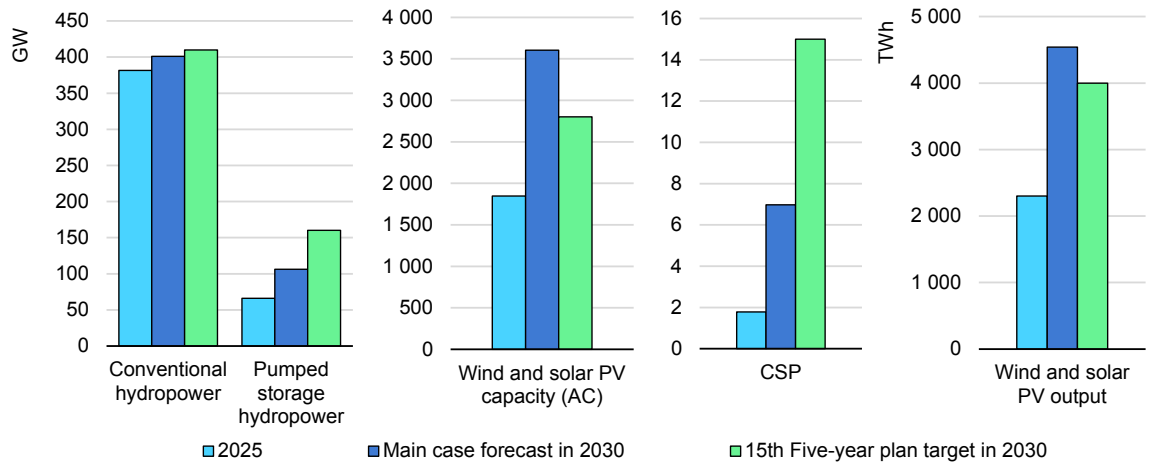
The 15th Five-Year Plan on Renewable Energy Development introduces updated goals for hydropower, PSH, wind, solar PV, CSP and ocean technologies. Our forecast is broadly aligned with the conventional hydropower target, while PSH deployment falls short in the main case due to long construction timelines, even though policy support is strong. For CSP, the forecast incorporates the new policy ambition, but the current project pipeline remains insufficient to meet the stated target of around 15 GW.

For solar PV and wind, the policy ambition suggests at least 2 800 GW of combined capacity (exceeding 50% of the total installed capacity in 2030); however, our forecast is higher, indicating over 3 600 GW. The plan also introduced a target of 4 000 TWh of combined wind and solar PV electricity

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generation by 2030. However, our main-case forecast exceeds this level by around 540 TWh, reflecting higher expected capacity deployment and continued growth in renewable electricity output beyond the minimum policy target.

China 15th Five-Year Plan goals or projections vs IEA forecast



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Notes: In this figure, the IEA forecast for solar PV is in alternating current (AC) because China's solar PV target is also in AC.

Growth continues to be driven by China's long-term targets, including carbon neutrality by 2060, implemented through provincial competitive auctions and contracts for difference. These mechanisms have already activated large volumes of new capacity, with prices remaining highly competitive. The continued expansion of large-scale renewable energy bases in inland regions, supported by transmission investments, low-cost financing and greater deployment of storage technologies, underpins strong capacity growth.

However, revenue-stability and system-integration challenges for renewable energy developers are becoming more prominent with rapidly rising curtailment of variable renewables. While contracts for difference provide partial revenue certainty, project exposure to wholesale price volatility remains significant. Capture prices are relatively low, particularly for solar PV, and rising curtailment – especially in northern and western provinces – is placing additional pressure on project economics. At the same time, grid infrastructure, including distribution networks, is struggling to keep pace with rapid electrification and the expansion of variable renewables.

In the accelerated case, renewable capacity additions could be 13% higher than in the main case, led by stronger solar PV and onshore wind deployment alongside additional growth in storage technologies. Achieving this increase would require further policy efforts, including expanded auction volumes, improved

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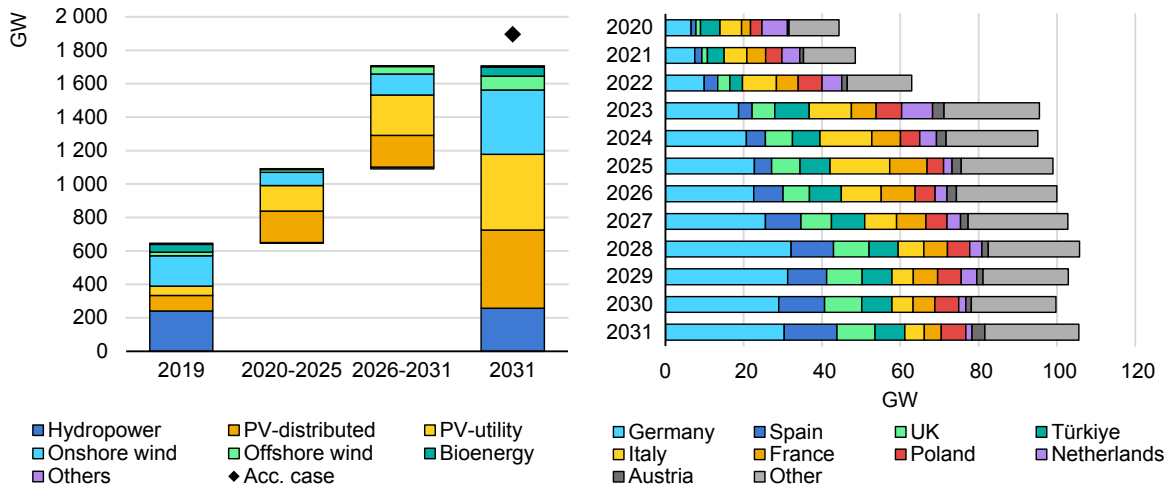
contract design to enhance revenue visibility, faster implementation of power market reforms, accelerated grid expansion and greater deployment of flexibility options such as battery storage and pumped-storage hydropower.

Europe

Europe's renewable energy expansion remains strong but plateaus as grids, permitting and weaker distributed PV slow momentum

Europe is forecast to add over 615 GW of renewable electricity capacity over 2026-2031, almost 40% more than during 2020-2025. However, annual additions are expected to remain broadly stable at around 100-105 GW throughout the forecast period. This reflects a shift from the crisis-driven surge in distributed solar PV towards utility-scale solar PV and wind, for which deployment is increasingly constrained by grid-capacity, permitting and system-integration challenges.

Renewable capacity additions in Europe by technology and country, 2020-2031



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Notes: Acc.case = accelerated case. UK = United Kingdom.

Solar PV continues to be the main source of expansion over 2026-2031, with utility-scale and distributed systems together making up roughly 70% of Europe's capacity additions, followed by onshore and offshore wind. Germany remains the largest market, registering almost 30% of regional growth, while the United Kingdom, Italy, Türkiye, Spain, France, Poland and the Netherlands together account for nearly half.

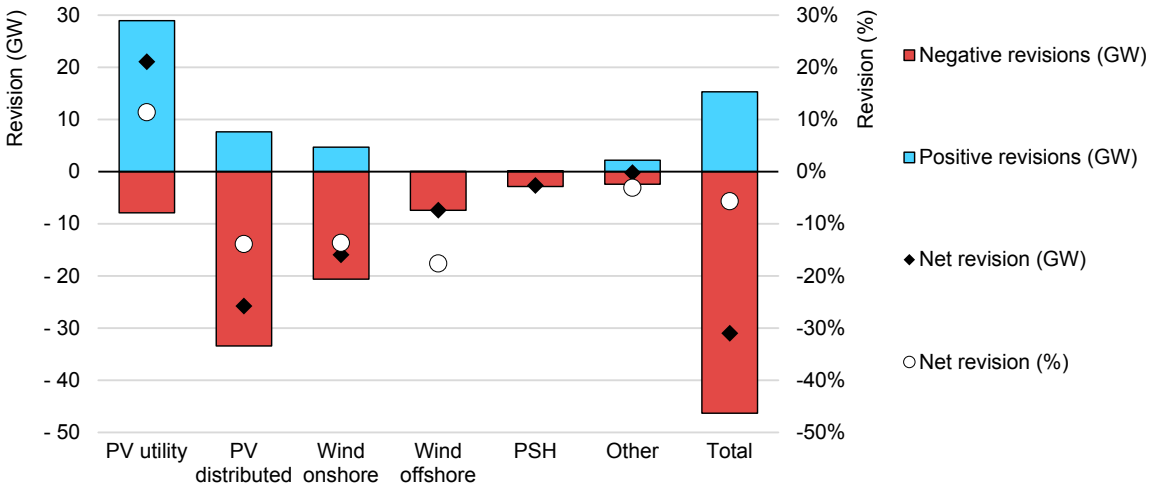
We have revised the forecast down 6% from last year, primarily because of 14% weaker distributed solar PV deployment. Following the exceptional expansion

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triggered by the energy crisis after the Russian Federation's (hereafter, "Russia") invasion of Ukraine, distributed PV markets are becoming saturated as policy support declines and retail electricity prices fall from crisis peaks. Higher electricity prices associated with the current conflict in the Middle East have not yet translated into major policy revisions or a measurable acceleration in installations.

This decline is partly offset by stronger utility-scale PV deployment arising from successful auctions in Italy, Germany, Poland and France, and by faster merchant and corporate-PPA-backed investments in Bulgaria, Greece and Spain.

Europe renewable capacity expansion revisions by technology, *Renewables 2025* to *Renewables 2026*, 2026-2030



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Note: PSH = pumped-storage hydropower.

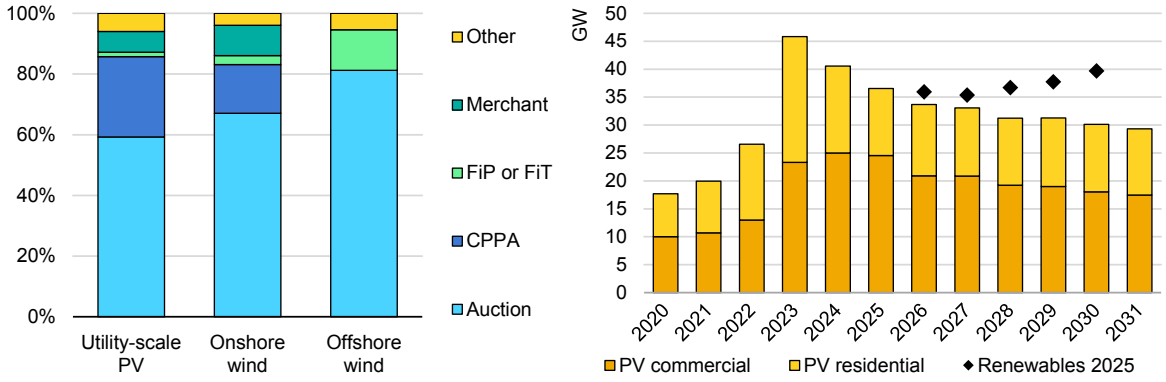
Our wind deployment forecast has also been revised down 15% due to permitting and project-development delays that continue to slow the commissioning of onshore wind farms in most markets. These effects are only partly offset by larger corporate PPA volumes in Portugal, merchant projects in Hungary and simplified grid connection rules in Türkiye. Offshore wind expectations have been revised down across several markets, including, the Netherlands, Germany, Ireland, Belgium and Lithuania, reflecting delayed project awarding and slower project and grid infrastructure development. Pumped-storage hydropower has the largest relative downward revision because projects in Spain, the United Kingdom, Croatia, Austria and Romania are developing more slowly than previously expected.

Auctions to award contracts for difference or fixed-price contracts remain the main driver of utility-scale solar PV and wind expansion in Europe. They are expected to catalyse over 80% of offshore wind, almost 70% of onshore wind and 60% of utility-scale solar PV deployment over 2026-2031.

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Corporate PPAs are the second most important procurement mechanism for utility-scale solar PV. Spain and Germany continue to lead the European market, with activity growing across Europe, especially in Greece, Italy, Denmark, Portugal, Sweden and Poland. By contrast, merchant deployment is expected to play a more limited role, as uncertainty over wholesale electricity prices, capture rates and curtailment continues to weigh on investment decisions.

Main drivers of utility-scale renewable capacity growth (left) and distributed PV annual net capacity additions in Europe, 2020-2031 (right)



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Notes: FiP = feed-in premium. FiT = feed-in tariff. CPPA = corporate power purchase agreement. "Other" category for offshore wind represents 5.9 GW of contracts for difference awarded in an administrative proceeding in Poland in 2021.

Distributed solar PV is expected to remain Europe's largest source of installed renewable energy capacity by 2031, despite annual deployment falling from the 45-GW peak in 2023 to less than 30 GW by the end of the forecast period – below last year's expectations. While annual additions in 2025 were in line with last year's expectations, early 2026 developments point to weaker deployment than previously forecast, as policy changes, market saturation and lower electricity prices weakened the business case for new systems.

In Germany, additions declined with the tightening of support measures and restrictions on electricity exports during low-price periods. At the same time, France reduced remuneration for smaller systems and shifted support towards self-consumption, while changes to net-metering schemes and subsidy reductions slowed deployment in Poland, Italy and the Netherlands.

System integration remains a key challenge across European markets. Grid congestion, long connection queues, curtailment and increasingly frequent low- or negative-price periods reduce project revenues and delay project development.

Permitting remains the second broad challenge, particularly for onshore and offshore wind. While Germany has demonstrated that reforms can expand the

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auction-ready project pipeline, lengthy approval procedures, legal challenges and land-use constraints continue to delay projects across much of Europe.

Additionally, offshore wind expansion is challenged by complex seabed-allocation, permitting, auction and grid-connection processes. At the same time, slower-than-expected electricity demand growth is reducing capture prices and corporate PPA demand, particularly in markets such as Spain and Finland where large industrial, hydrogen and data-centre projects have yet to materialise at scale.

In the accelerated case, Europe's renewable capacity deployment is about 30% higher than in the main case. The largest upside gains come from solar PV, for which faster deployment of storage, flexible demand, grid infrastructure and connection reforms would alleviate curtailment and improve project economics. For wind, stronger growth depends primarily on faster permitting, facilitated repowering, more predictable spatial planning, regular auction schedules and better co-ordination of project development and grid expansion.

These measures would also improve realisation rates for awarded projects and strengthen revenue certainty for corporate-PPA-backed investments. Faster renewable energy deployment will also require speedier electrification of energy use, particularly in the most advanced markets, to support additional electricity demand.

The EU renewable electricity target for 2030 is within reach, but only with faster grid, permitting and system integration progress

The European Union adds over 480 GW of additional renewable capacity over 2026-2031, accounting for almost 80% of deployment in Europe. Solar PV provides the majority of additions, while onshore wind accelerates in markets where auctions and permitting reforms have expanded the project pipeline.

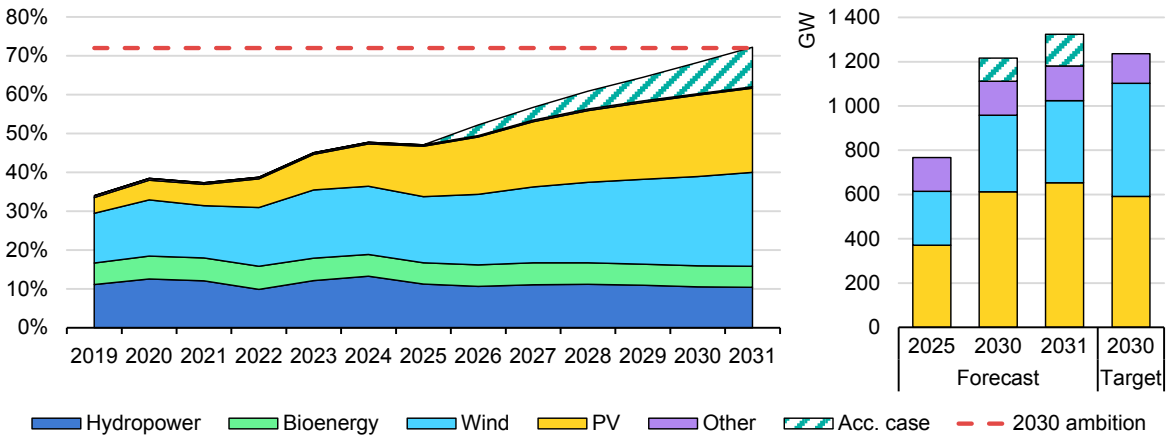
Offshore wind grows towards 2031 but remains below the trajectory towards EU countries' combined regional ambition of around 88 GW of offshore renewable capacity by 2030, due to delays in permitting, auctions and project development. Renewable capacity is expected to reach 1 255 GW by 2030 and 1 335 GW by 2031, over 55% above 2025 levels. However, renewable power generation remains below the REPowerEU target.

According to European Commission modelling, renewables reach 69% of gross final electricity consumption and 72% gross electricity generation by 2030, consistent with a 45% renewable share in gross final energy consumption. RED III subsequently set a binding EU-wide target of 42.5% by 2030, with an ambition to reach 45%. In the IEA main case, the renewables share in electricity generation reaches only 60% in 2030. There are three reasons for this gap: national ambitions remain below the level required to meet the EU-wide target; deployment delays

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are affecting the technologies with the highest generation potential, particularly offshore wind; and rising curtailment is reducing the generation delivered by installed wind and solar PV capacity.

EU renewable electricity generation shares (2019-2030) and REPowerEU 2030 ambition (left), and installed renewable capacity (2025-2031) and REPowerEU 2030 ambition (right)



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Notes: Solar PV capacity values are in alternating current (AC). "Other" in the right figure includes conventional hydropower, bioenergy, geothermal, concentrated solar power (CSP) and ocean technologies and excludes pumped-storage hydropower (PSH). Acc. Case = accelerated case.

Sources: REPowerEU ambitions for total renewable capacity, and wind and solar PV capacity are from Implementing the REpowerEU Action Plan. The solar PV ambition is in AC, as it is similar to the "almost 600 GW by 2030" target identified in the EU Solar Energy Strategy SWD (2022) 148 final. The 2030 EU offshore wind ambition is from Delivering on the EU Offshore Renewable Energy Ambitions, and the onshore wind aim is the difference between the 520-GW REPowerEU ambition and the 111-GW offshore wind target in Delivering on the EU Offshore Renewable Energy Ambitions.

In terms of installed-capacity ambitions, the European Union is expected to reach the 2030 solar PV target of 592 GW (in alternating current [AC]),[2] but it falls short of the 510-GW wind ambition by more than 30%.[3] As a result, total 2030 renewable capacity is around 13% below the 1 236-GW target[4] when calculated using the European Commission's methodology.

This shortfall does not result from a lack of policy support. Competitive auctions remain widespread, corporate PPAs continue to expand, RED III provides a framework for faster permitting and the European Grids Package aims to alleviate grid connection bottlenecks.

The challenge is implementation. Germany's permitting reforms and auction volumes support stronger growth, but offshore wind deployment remains delayed.

[2] The solar PV target is 592 GW in the Commission Staff Working Document COM (2022) 2030 final. We assume this value is in AC since it is similar to the "almost 600 GW by 2030" solar PV target identified in the EU Solar Energy Strategy SWD (2022) 148 final.
[3] The 2030 ambition for wind refers to the Implementing REPowerEU Plan SWD.
[4] As per the REPowerEU Plan SWD (2022) 230 final, assumed to exclude pumped storage (as illustrated in the Implementing REPowerEU Plan SWD) and to include solar PV in AC (as referred to in the EU Solar Energy Strategy).

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Italy's FER X framework strengthens the utility-scale solar PV pipeline, but transmission and permitting constraints continue to affect project delivery. Spain has a large project pipeline but requires faster demand growth, storage deployment and grid expansion. In France, lower distributed-PV remuneration hampers deployment, while in Poland and Romania growing auction activity is increasingly constrained by grid connection availability.

Auctions remain the main driver of utility-scale deployment in the European Union. Under the EU Net-Zero Industry Act (NZIA) and its implementing regulation, each member state must apply the prescribed non-price sustainability and resilience criteria to at least 30% of the auction volume each year, or alternatively at least 6 GW per year. Italy became the first member state to apply the related provisions in its 2025 FER X tender, which awarded around 1.1 GW to projects meeting supply-chain resilience requirements. As industrial policy goals become increasingly integrated into auction design, balancing supply-chain objectives with competition and timely project delivery will be increasingly important.

The 72% renewable electricity generation share required to meet the REPowerEU modelling is achieved in the accelerated case, but only with stronger policy implementation and faster infrastructure deployment.

Higher and more predictable auction volumes, especially for onshore and offshore wind, would be required to provide long-term investment visibility. Auction designs across countries would also need to better reflect financing, construction and grid-delivery risks while ensuring bankable revenues for developers. At the same time, stronger corporate PPA frameworks could broaden market access and improve project economics.

Investing in system flexibility is equally important. Employing batteries, pumped-storage hydropower, demand response, interconnections and flexible electricity consumption can reduce curtailment, improve capture prices and increase the value of renewable power generation. In parallel, member states would need to speed up permitting reforms, implement renewable-acceleration areas and streamline project approvals without weakening environmental safeguards. For wind, repowering turbines and making spatial planning more predictable could further expand the project pipeline.

Addressing grid constraints remains key to achieve faster renewable energy expansion in the European Union. Connection queue reforms are expanding across member states and are helping system operators allocate grid capacity more efficiently through stricter readiness requirements and the removal of speculative projects. While these measures should improve project realisation rates, they cannot substitute for investment in transmission and distribution networks. Better co-ordination of renewable procurement, grid expansion and

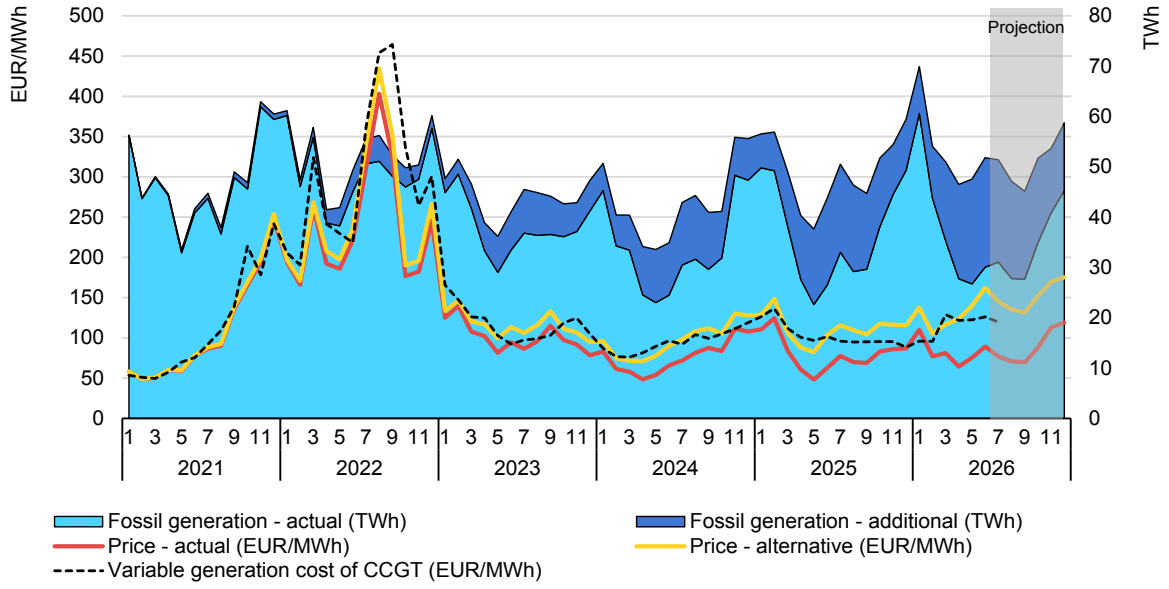
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connection availability will therefore remain essential, particularly for offshore wind and for renewables-rich regions located far from demand centres.

If solar PV and wind capacity had not expanded rapidly since 2021, wholesale electricity prices in the European Union would be significantly higher

Since 2021, policy measures responding to the energy crisis after Russia's invasion of Ukraine have accelerated renewable energy deployment across the European Union. The resulting increase in solar PV and wind generation has strengthened energy security by curbing reliance on imported fossil fuels and lowering exposure to volatile fuel prices. At the same time, rising solar PV and wind generation has also reduced the need for gas- and coal-fired generation, particularly during periods of high renewable energy output.

EU monthly fossil fuel electricity generation, actual and Low-RES wholesale electricity spot prices, and estimated variable CCGT generation cost, 2021-2026



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Notes: Low-RES = low renewable energy sources. CCGT = combined-cycle gas turbine. The analysis covers Austria, Belgium, Finland, France, Germany, Greece, Italy, the Netherlands, Poland, Portugal and Spain. The low-RES scenario assumes no solar PV or wind capacity additions since 2021.

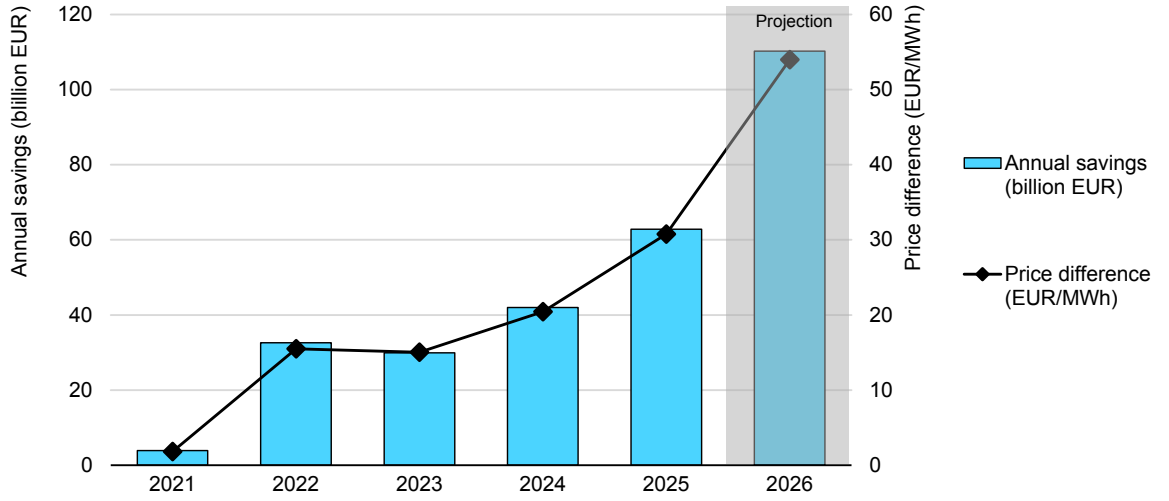
During 2021-2025, the European Union installed around 270 GW of solar PV capacity, tripling the size of its solar fleet, and almost 70 GW of wind capacity, increasing generation from these technologies by more than 300 TWh – equivalent to around 11% of EU electricity consumption. This additional low-marginal-cost generation displaced higher-cost fossil fuel-based generation (primarily from natural gas and, in some markets, coal) in the merit order.

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Additional solar PV and wind capacity helped shield EU consumers from fossil fuel price volatility by reducing the role of high-marginal-cost thermal generation in electricity price formation. Absent the renewable capacity added since 2021, higher fossil fuel prices stemming from the current conflict in the Middle East would have had a greater impact on electricity prices in 2026.

To quantify this impact, we compared actual market outcomes with an alternative, counterfactual low-renewable-energy-source (Low-RES) scenario that assumes no solar PV or wind deployment since 2021.[5] The results indicate that wholesale electricity prices would have been almost EUR 55/MWh higher in 2026, raising total electricity supply costs by more than EUR 280 billion over 2021-2026.

EU electricity prices and total supply cost differences, actual vs Low-RES scenario, 2021-2026



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Notes: The analysis covers Austria, Belgium, Finland, France, Germany, Greece, Italy, the Netherlands, Poland, Portugal and Spain. The Low-RES scenario assumes no solar PV or wind capacity additions since 2021. 2026 values include IEA estimates.

The impact of renewable energy deployment on electricity prices has become stronger over time with expansion of the renewable power fleet and continued fossil fuel price volatility. While lower fuel prices moderated the effect in 2023 and 2024, continued solar PV and wind deployment has maintained downward pressure on fossil fuel-based generation and wholesale prices. In 2026, with the combination of a larger renewable energy fleet and steep fossil fuel prices,

[5] Potential wholesale electricity prices in the Low-RES scenario were estimated based on the historical relationship between hourly natural gas and hard coal generation and wholesale electricity prices. This relationship, estimated separately for each quarter, was used to simulate hourly wholesale prices under an alternative scenario with lower renewable generation and consequently higher fossil fuel generation. The total cost of electricity supply was calculated as the product of total electricity supply and the simulated wholesale price. The analysis covers Austria, Belgium, Finland, France, Germany, Greece, Italy, the Netherlands, Poland, Portugal and Spain.

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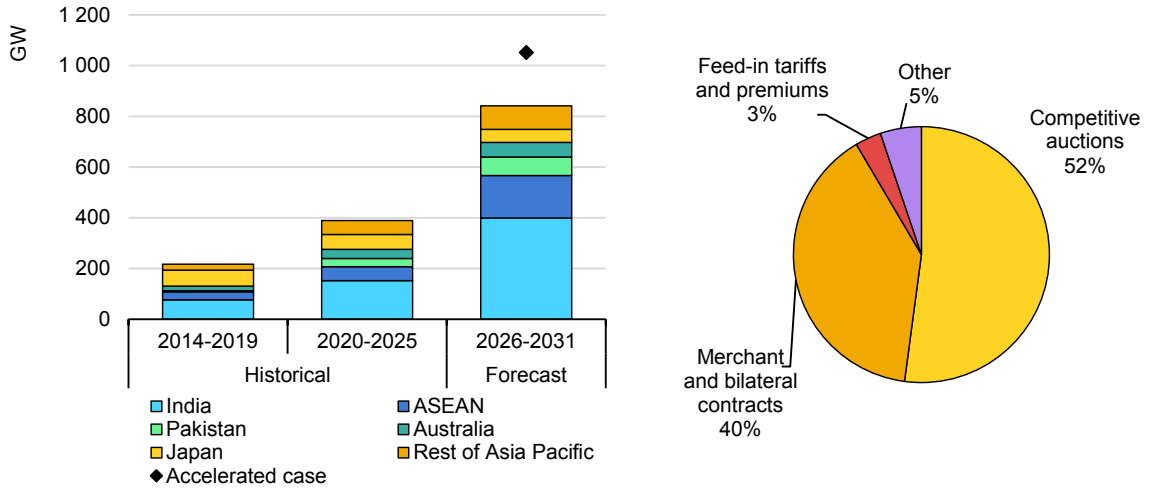
renewables were delivering the highest-ever reduction in wholesale electricity prices. Solar PV has the strongest impact during daylight hours, particularly in the spring and summer, while wind provides a broader seasonal benefit during winter periods when electricity demand and reliance on gas-fired generation are typically higher.

Asia Pacific

The Asia-Pacific renewable energy forecast has been revised upwards as stronger Indian and ASEAN solar PV growth more than offsets the region's lower wind and hydropower outlook

Asia Pacific, excluding China, is forecast to add more than 840 GW of renewable capacity over 2026-2031, more than doubling 2020-2025 additions and raising installed capacity to almost 1 700 GW by 2031. India accounts for nearly half of the regional expansion, followed by ASEAN at 20%, while Pakistan, Australia and Japan together contribute just over one-fifth.

Asia-Pacific renewable capacity additions by market, 2014-2031 (left) and gross utility-scale additions by procurement type, 2026-2031 (right)



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Notes: ASEAN = Association of Southeast Asian Nations. Asia Pacific excludes China.

Solar PV leads the expansion, representing almost 80% of capacity additions, while onshore wind contributes 12% and hydropower 7%.

Competitive auctions drive over half of utility-scale renewable capacity growth in the Asia-Pacific region, led by India's central and state procurement programmes, Australia's Capacity Investment Scheme, Korea's fixed-price contract auctions and the Philippines' Green Energy Auction Programme. Corporate PPAs

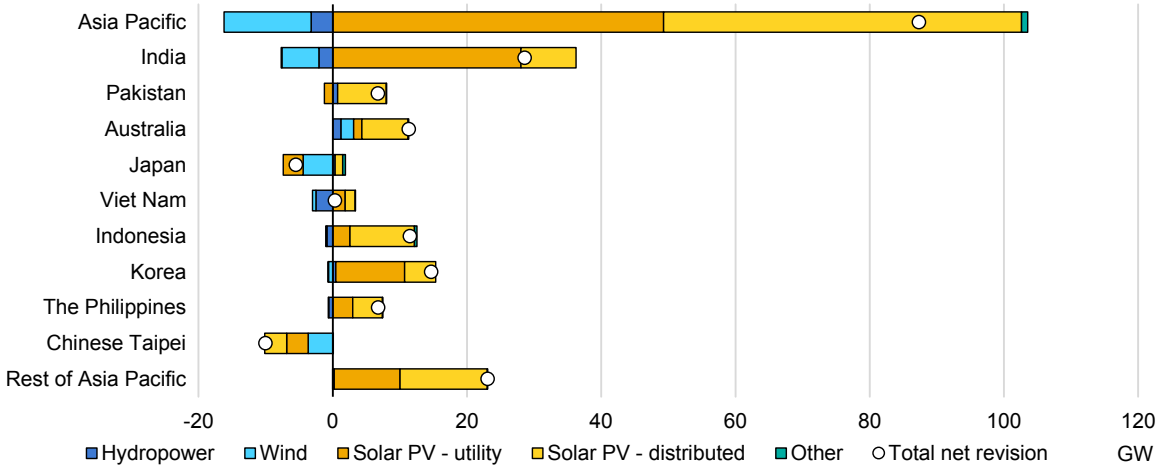
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contribute another 25% and are becoming an increasingly important route to market in India, Viet Nam, Korea and Japan. Unsolicited bilateral contracts represent around 13% of deployment, particularly in vertically integrated markets such as Indonesia. Utility-owned projects, feed-in tariffs and merchant investments spur the remaining growth.

Asia-Pacific renewable energy markets are increasingly diverging as deployment matures. In advanced markets, including Australia, Japan and Korea, system integration is emerging as the key challenge, with grid constraints, curtailment and insufficient flexibility increasingly limiting growth. As solar PV penetration rises, investing in networks, storage and demand-side flexibility is becoming as important as new capacity additions.

In contrast, less mature markets remain focused on translating policy ambition into deployment. Countries such as Indonesia, the Philippines, Thailand and Viet Nam have strengthened their renewable energy targets and support frameworks, but grid connection, permitting, project execution and land acquisition challenges continue to slow implementation.

Asia-Pacific renewable capacity expansion changes from *Renewables 2025* to *Renewables 2026* by technology and selected market, 2026-2030



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Across the region, investment increasingly depends on bankable revenue streams and predictable regulation. Inadequate grid infrastructure, project bankability and policy execution remain common barriers, highlighting the growing importance of robust market design and revenue certainty.

Our 15% (87 GW) upward revision to last year's Asia-Pacific renewable energy forecast primarily reflects stronger solar PV growth, which more than offsets lower expectations for wind and hydropower. Upward revisions are led by India, Korea,

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Indonesia, Australia, the Philippines, Pakistan, Malaysia, New Zealand and Thailand, while forecasts for Japan and Chinese Taipei have been revised downwards.

With the solar PV outlook raised by more than 100 GW (+24%) for 2026-2030, it makes up almost the entire upward revision to the regional forecast, led by stronger deployment in India, Korea, Indonesia and Australia. Utility-scale solar PV contributes almost half of the increase, owing primarily to India's stronger-than-expected deployment and large pipeline of auction-awarded and open-access projects. These gains more than offset downward revisions to utility-scale solar PV in Pakistan and Japan, while Chinese Taipei's outlook has been scaled back due to permitting, land-use and social acceptance challenges.

Distributed solar PV constitutes more than half of the solar PV upward revision. Indonesia accounts for the largest increase, thanks to stronger commercial and industrial demand, greater ambition, planned expansion of rooftop solar quotas and improved PPA arrangements. In India, continued growth under the PM Surya Ghar and KUSUM programmes, improved economics and stronger-than-expected recent deployment support a higher solar PV outlook. Meanwhile, Pakistan's upward revision reflects continued consumer-led deployment of distributed and off-grid solar PV in response to high electricity tariffs and power supply unreliability.

Onshore wind has been revised down by over 9 GW, led by India and Japan. In India, lower dedicated auction volumes and growing competition from solar PV paired with battery storage weaken deployment prospects. In Japan, persistent project realisation challenges continue to delay deployment. Upward revisions in Australia, Korea and Thailand, reflecting larger procurement volumes and policy support, only partly offset these reductions.

Offshore wind receives the largest relative downward revision among renewable technologies. This year's forecast is over 30% lower than last year's, primarily because of project delays and cancellations in Chinese Taipei and Korea, as well as continuing supply chain, permitting and financing challenges. Progress in Viet Nam's offshore wind project pipeline, resulting from better project-level visibility and new regulations addressing earlier bottlenecks, only partly offsets these reductions.

Hydropower additions remain sizeable despite a modest downward revision. Asia Pacific continues to be the world's second-largest hydropower growth market, although delays in India and Viet Nam scale back the outlook for conventional hydropower. Higher expectations for Pakistan and Australia partly offset these reductions. Pumped-storage hydropower has been revised upwards for Australia and India, reflecting rising flexibility needs as renewable energy penetration increases.

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Meanwhile, the bioenergy and geothermal forecasts have been revised upwards. Stronger bioenergy deployment in Japan and faster geothermal expansion in Indonesia, supported by policy measures and improved project economics, contribute to higher growth expectations for both technologies.

Capacity additions across the region could be 25% higher in the accelerated case, reaching more than 1 000 GW over 2026-2031. Realising this upside potential would require faster grid expansion and connection, greater deployment of storage and flexibility resources, and higher execution rates for awarded and advanced-stage projects.

In India, higher auction volumes, faster contract signing, improved DISCOM finances and accelerated transmission and storage deployment would support faster renewable capacity growth. In ASEAN, faster implementation of power development plans and support schemes, more efficient procurement, permitting and project execution, stronger grid investment and enhanced regional interconnections would unlock further growth, particularly in Indonesia, Viet Nam and the Philippines. Across advanced Asia-Pacific markets, faster grid expansion and grid connections, more storage and system flexibility, streamlined permitting and stronger revenue certainty would improve project realisation and enable quicker renewable energy deployment.

United States

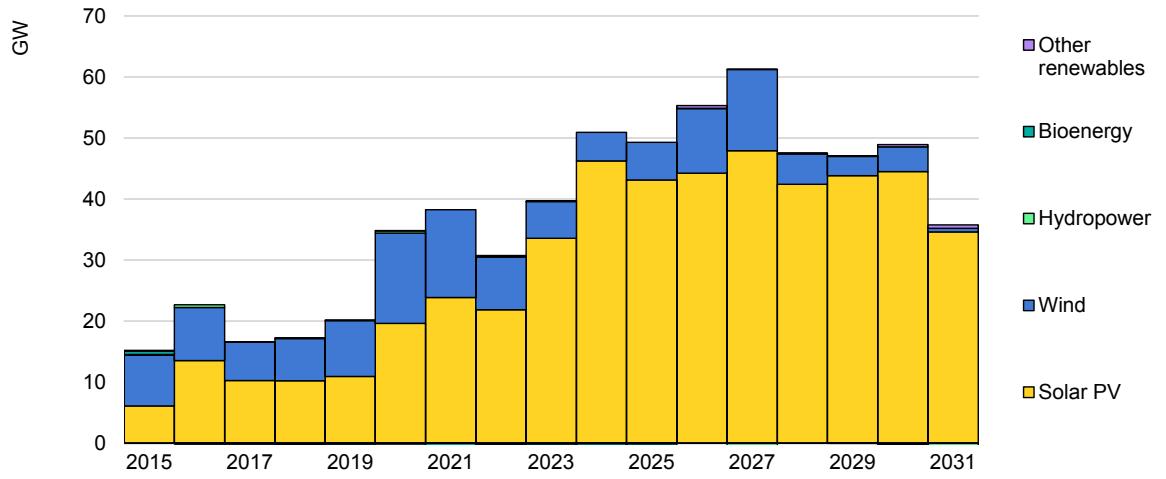
Solar PV makes up most forecast growth, as it can be deployed more quickly than other energy options to meet growing electricity demand, mainly from data centres

The United States is forecast to add almost 314 GW of renewable capacity over 2026-2031, 30% more than during 2020-2025. Annual additions reached 49 GW in 2025 and are expected to average around 52 GW over the forecast period, with strong near-term deployment followed by slower growth. Solar PV accounts for almost 90% of capacity additions followed by wind.

The renewable capacity forecast has been revised up by 40% from last year, driven primarily by stronger solar PV deployment, particularly in the utility-scale segment. Solar PV systems along with battery storage can be installed swiftly to meet rapidly growing electricity demand from data centres, supporting continued deployment. This reflects a larger pipeline of projects seeking to qualify for federal tax incentives before eligibility deadlines arrive. Robust residential installations ahead of expiring federal tax incentive contribute to the growth, while corporate demand and improving economics sustain commercial PV. A growing solar-plus-storage pipeline further supports deployment by reducing exposure to declining capture prices and negative-price periods.

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United States renewable electricity net capacity additions by technology, main case



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Notes: Solar PV capacity is in direct current (DC). "Other renewables" include geothermal energy, concentrated solar power and marine power.

The wind outlook is also slightly more optimistic following the substantial downward revision in last year's forecast. Projects qualifying for existing tax incentives support near-term additions, but growth moderates after 2027 as some federal incentives phase down or expire and permitting challenges persist. Offshore wind remains constrained by the temporary halt on new federal leasing, permitting and approvals. Geothermal is revised up by more than 20% owing to a stronger project pipeline and growing interest in enhanced geothermal systems, whereas hydropower growth mainly reflects refurbishment and modernisation of existing plants. Meanwhile, some bioenergy capacity is retired.

Near-term growth is underpinned by the acceleration of projects aiming to qualify for federal tax credits, while state policies and corporate procurement increasingly drive uptake. Safe-harbour provisions allow eligible projects to retain federal support beyond the initial construction deadline. As federal incentives decline, however, state renewable portfolio standards, clean-energy standards and procurement programmes are expected to provide a larger share of policy support. Corporate PPAs, particularly from data centres and large industrial consumers, offer additional revenue certainty and respond to rapidly rising electricity demand.

Annual capacity additions decline after 2027 as tax incentives phase out. In addition, Foreign Entity of Concern (FEOC) requirements, trade measures and uncertainty over implementation rules reduce long-term investment visibility. Tariffs on imported solar equipment and supply-chain compliance requirements could raise costs and constrain equipment availability. Long interconnection queues and insufficient transmission capacity continue to delay commissioning and increase development costs across most regions, despite ongoing queue

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reforms. In parallel, rapid solar PV deployment places downward pressure on daytime wholesale prices and increases exposure to negative-price periods. Storage and long-term offtake contracts therefore become increasingly important for project revenues and bankability.

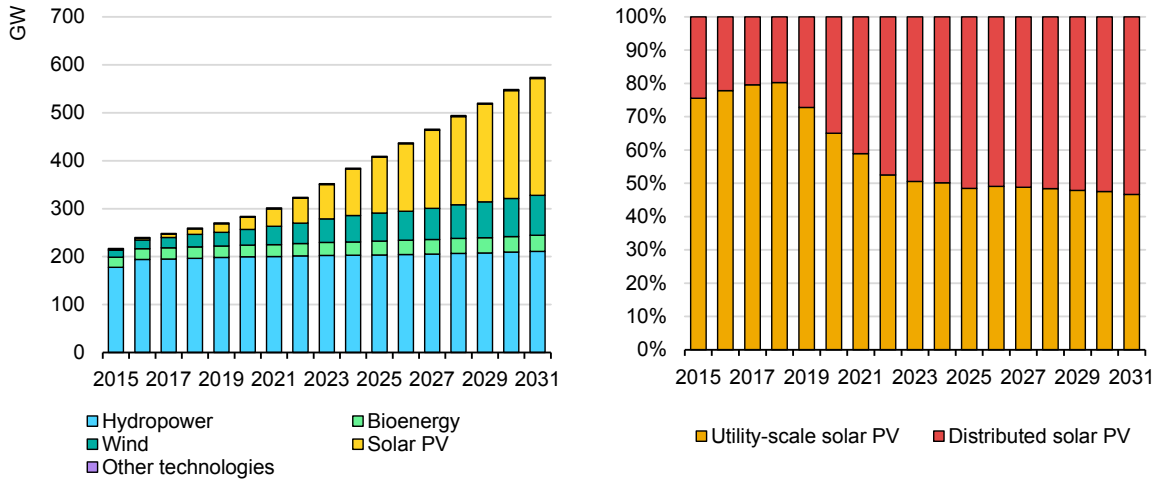
In the accelerated case, renewable capacity additions could be significantly higher than in the main case, with the largest upside gains from solar PV, followed by wind and geothermal. Realising this potential would require clear implementation rules for tax credits and Foreign Entity of Concern provisions; faster transmission expansion and interconnection reform; stronger corporate procurement from data centres, manufacturing and industry; shorter permitting and siting timelines; and faster deployment of batteries, demand response and other flexible resources. Together, these measures would improve investment certainty, project realisation and the integration of higher shares of solar PV and wind.

Latin America and the Caribbean

Solar PV leads renewable capacity growth as the regional technology mix shifts away from hydropower dominance

The Latin America and Caribbean region is forecast to add 165 GW of renewable electricity capacity during 2026-2031, with solar PV making up almost 80%. By the end of the decade, installed solar PV capacity is expected to surpass hydropower's to become the largest source of installed capacity.

Renewable capacity installed in Latin America and the Caribbean by technology (left), and solar PV shares by segment (right)



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Notes: "Other technologies" includes concentrated solar power, and geothermal and ocean energy. Solar PV values are expressed in direct current (DC).

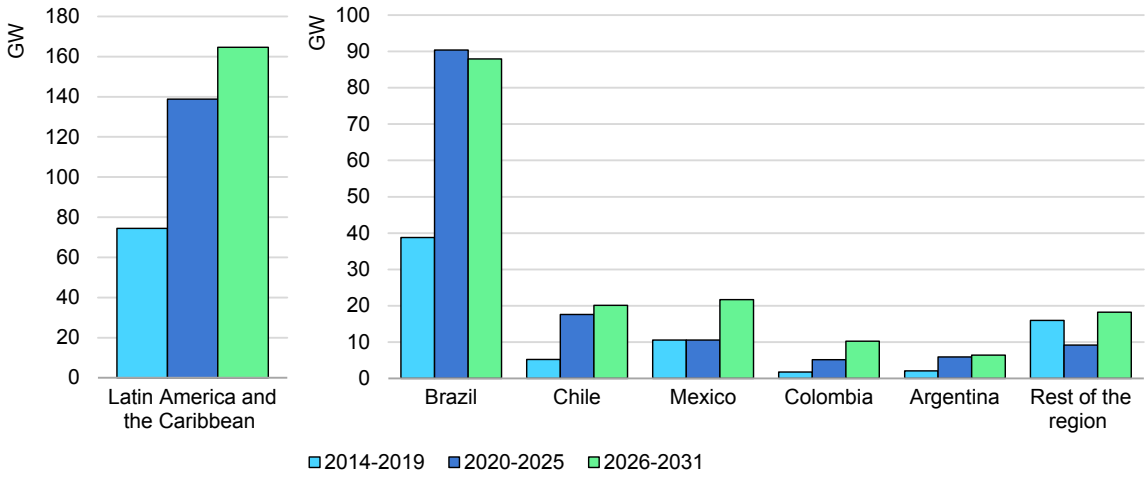
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During the 2010s, onshore wind was the main source of renewable capacity growth in Latin America, led by Brazil. However, **annual additions have plateaued and are expected to remain broadly stable through 2031** as transmission constraints, curtailment and fewer auction opportunities hamper deployment, particularly in Brazil. Chile is expected to account for a growing share of regional wind growth towards the end of the forecast period.

Solar PV has emerged as the region's dominant growth technology, led by Brazil and supported by expanding deployment in Chile and Mexico. While utility-scale solar growth moderates in Brazil due to grid constraints and weaker procurement, strong project pipelines, corporate PPAs and new auction activity in Chile and Mexico continue to sustain regional expansion.

Distributed solar PV is forecast to become the largest source of renewable capacity additions over 2026-2031. Most growth happens in Brazil, where net metering, high retail electricity prices and declining technology costs continue to encourage investment, while Mexico's net-metering framework sustains steady deployment.

Net renewable capacity additions in Latin America and the Caribbean and selected countries



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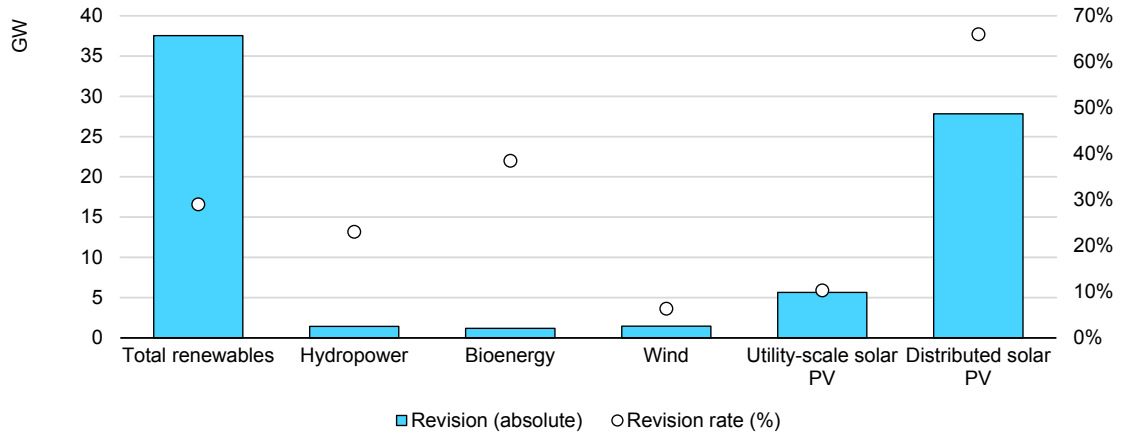
Brazil remains the region's largest renewable energy market, with almost 90 GW of renewable additions forecast for 2026-2031. Solar PV accounts for 86% of new capacity, increasingly in the form of distributed systems. Net metering, falling solar costs and strong free-market PPA activity continue to support deployment. However, fewer auctions, transmission bottlenecks and rising curtailment are slowing utility-scale solar PV and wind growth despite ongoing efforts to expand the grid as well as storage facilities.

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Mexico is forecast to more than double its renewable capacity additions compared with 2020-2025, with solar PV accounting for over 90% of growth. Utility-scale solar benefits from the reopening of large-scale procurement through the new CFE-led auction scheme, while net metering continues to support distributed PV. Key challenges include grid constraints, permitting delays and uncertainty around the balance between state control and private-sector participation.

Chile is expected to add around 20 GW of renewable capacity between 2026 and 2031, with solar PV accounting for about two-thirds of growth and wind for most of the remainder. Strong solar and wind resources and growing corporate PPA demand support deployment. However, transmission congestion, curtailment and an increasing number of zero-price hours are becoming major challenges, reducing project revenues and making grid expansion and battery storage crucial for future growth.

Renewable capacity forecast revisions for Latin America and the Caribbean by technology, 2026-2030



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Note: Solar PV values are expressed in direct current (DC).

Compared with last year's forecast, renewable capacity additions in Latin America and the Caribbean have been revised up by 12 GW (9%), primarily reflecting stronger distributed solar PV deployment. Nearly three-quarters of the upward revision comes from distributed PV, led by Brazil, where favourable net-metering conditions and continued cost declines outweigh the impact of new grid-use charges. Utility-scale solar PV prospects are lower than last year, mainly because of weaker expectations for Brazil and Chile, where transmission constraints, rising curtailment and lower auction activity are slowing large-scale deployment.

Onshore wind expectations remain broadly unchanged at the regional level, as stronger growth in some markets offsets weaker prospects in Brazil and

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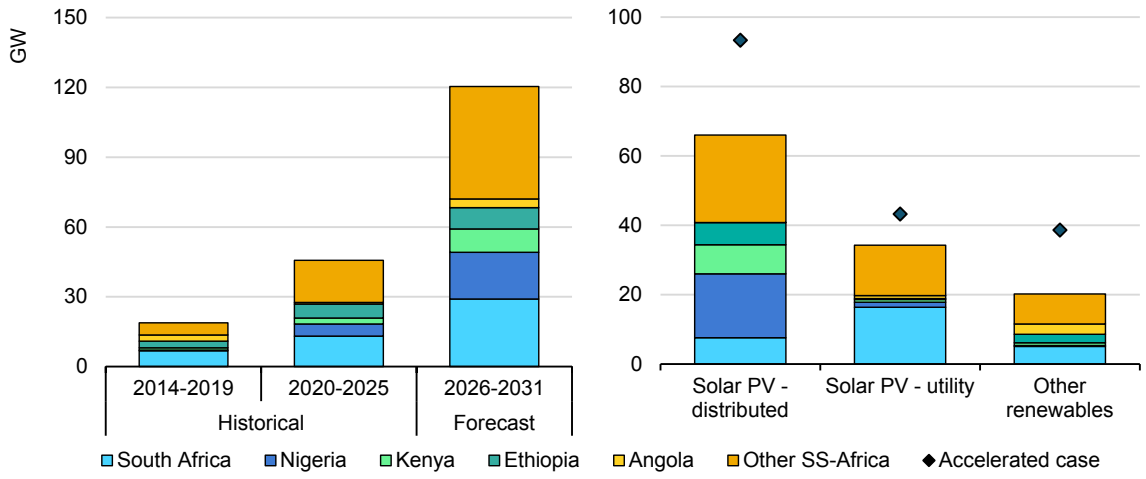
Mexico. Overall, the forecast revision reinforces Latin America's shift towards a more solar-led growth model, with distributed PV accounting for the majority of additional capacity.

Sub-Saharan Africa

Distributed solar PV uptake accelerates renewable energy growth across sub-Saharan Africa, led by South Africa and Nigeria

Sub-Saharan Africa is forecast to add over 120 GW of renewable electricity capacity over 2026-2031, almost doubling today's installed base and marking a clear acceleration from 2020-2025. Growth is concentrated in South Africa and Nigeria, which together account for over 40% of the regional capacity expansion, followed by Kenya, Ethiopia and Angola. Solar PV dominates the forecast, representing over 80% of new capacity, while hydropower's share of new deployment continues to decline despite remaining important in several markets.

Renewable capacity additions in sub-Saharan Africa by market, 2014-2031 (left) and by technology, 2026-2031 (right), main and accelerated cases



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Notes: SS = sub-Saharan. Capacity additions refer to net additions.

The main structural shift in the region is the rapid expansion of distributed solar PV. Residential, commercial and off-grid systems account for nearly two-thirds of all new solar PV capacity over the forecast period, led by Nigeria, South Africa and Kenya, but increasingly supported by broader uptake across smaller markets. This growth is driven less by centralised procurement than by consumers seeking more reliable and affordable electricity amid weak grid reliability, high tariffs, rising diesel generation costs and falling solar PV and battery prices. In

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Nigeria, fuel subsidy removal, mini-grid regulation and the introduction of net billing improve project economics, while South Africa's deregulation of private distributed generation continues to support commercial, industrial and residential deployment. In Kenya, however, high electricity prices and supply unreliability remain the key drivers of distributed solar PV uptake.

Utility-scale solar PV growth remains more concentrated. South Africa accounts for 48% of the region's utility-scale PV additions, supported by the Renewable Energy Independent Power Producer Procurement Programme (REIPPPP), corporate PPAs and Eskom's wheeling arrangements. Outside South Africa, deployment is rising in Kenya, Namibia and Senegal, supported by dedicated procurement rounds, feed-in tariffs and offtaker guarantees, while state-led projects and development finance underpin growth in Nigeria, Ghana, and Angola. However, weak grid infrastructure, transmission bottlenecks and project bankability challenges continue to limit the pace of utility-scale expansion, especially in South Africa and Nigeria.

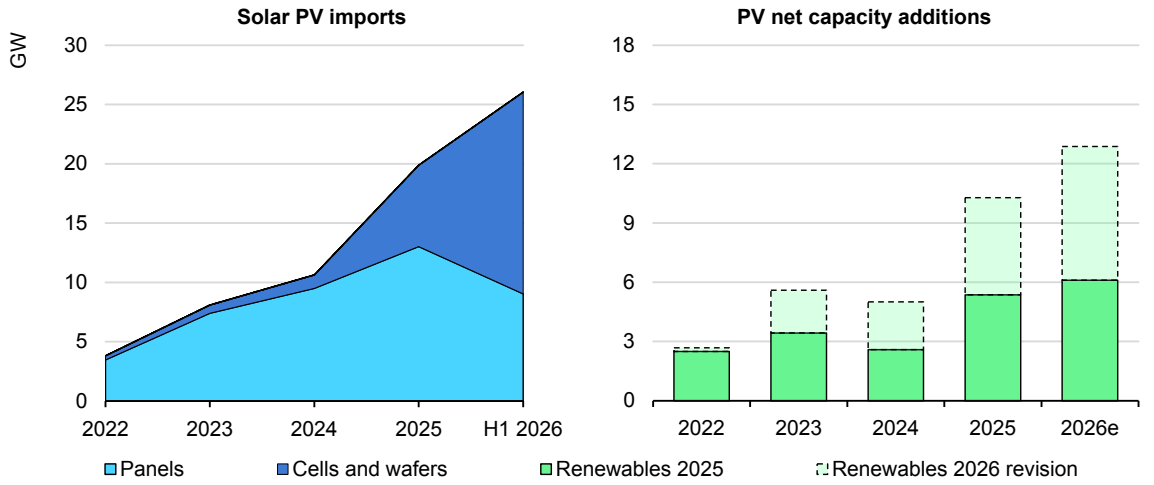
Onshore wind growth remains modest and highly concentrated. Around 10 GW of new wind capacity is expected over the forecast period, with South Africa responsible for roughly half of additions through REIPPPP awards and corporate PPAs. Although wind projects benefit from strong resource availability in several markets, deployment is increasingly constrained by limited grid connection availability, particularly in South Africa's Eastern and Western Cape provinces where the best wind resources are located. Outside of South Africa, wind growth remains relatively limited and dependent on support from national utilities and development finance institutions, with additions concentrated in markets such as Senegal, Ethiopia and Kenya.

While solar PV makes up most additions, hydropower remains an important source of new capacity in some markets. Around 9 GW of hydropower is forecast for 2026-2031, with Angola and Ethiopia accounting for 50% of the regional increase. Large projects, including Angola's Caculo-Cabaça hydropower station and Ethiopia's Koysha hydroelectric project, underpin much of this growth.

The regional forecast has been revised up 54% (33 GW) from last year, based almost entirely on distributed PV, which has been upgraded by 42 GW, reflecting faster consumer-led deployment and improved accounting of historically underestimated distributed capacity. However, the upward revision for distributed PV is partly offset by a near 7 GW downward revision to utility-scale PV, reflecting higher offtaker risks, financing constraints and limited transmission availability. Meanwhile, the hydropower forecast is revised down by 2 GW, as the Grand Ethiopian Renaissance Dam reached full commissioning in September 2025, ahead of the forecast period and earlier than previously expected, and several large projects in Ethiopia and Nigeria have been delayed beyond 2031.

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Annual sub-Saharan Africa imports of PV modules from China (left) and PV capacity revisions (right), 2022-2026



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Note: e = estimated.
Source: Ember (2026), China's Solar PV Exports.

Long-term planning and energy-access initiatives still support the region's renewable energy outlook. Updated planning frameworks, including South Africa's Integrated Resource Plan and Nigeria's National Integrated Resource Plan, provide a basis for future deployment, while Mission 300 continues to support grid-based and off-grid electrification. A domestic solar PV manufacturing push is also emerging, led by Nigeria, which is expected to have around 500 MW/year of module assembly capacity in 2026, and is forecast to surpass 1 GW annually by 2031. However, these early-stage ventures are unlikely to materially reduce import dependence during the forecast period.

Regional challenges remain significant, keeping renewable capacity deployment in Africa well below the substantial potential. Grid capacity constraints and transmission bottlenecks are the largest barriers to utility-scale wind and solar PV deployment, particularly in South Africa and Nigeria. Government utility offtaker risk, weak revenue collection, and procurement uncertainty continue to undermine project bankability, while distributed PV is further constrained by limited local-currency financing access, foreign exchange volatility and import policy uncertainty. In several markets, the absence of clear frameworks for grid-connected battery storage also delays the next phase of variable renewable integration.

In the accelerated case, renewable capacity additions are 46% higher than in the main case, led by faster solar PV and wind deployment. The largest upside gains depend on faster transmission expansion, including implementation of South Africa's Transmission Development Plan and the Independent

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Transmission Infrastructure Procurement Programme. In Nigeria, a competitive utility-scale procurement framework, clearer licensing and wheeling rules, stronger distributed-generation regulation and bankable storage frameworks would encourage faster deployment. Expanded access to local-currency financing and continued development of domestic solar manufacturing could further strengthen distributed PV growth across the region.

Middle East and North Africa

The MENA renewable forecast remains stable as energy security measures and corporate demand offset a weaker renewable hydrogen outlook and supply-chain delays

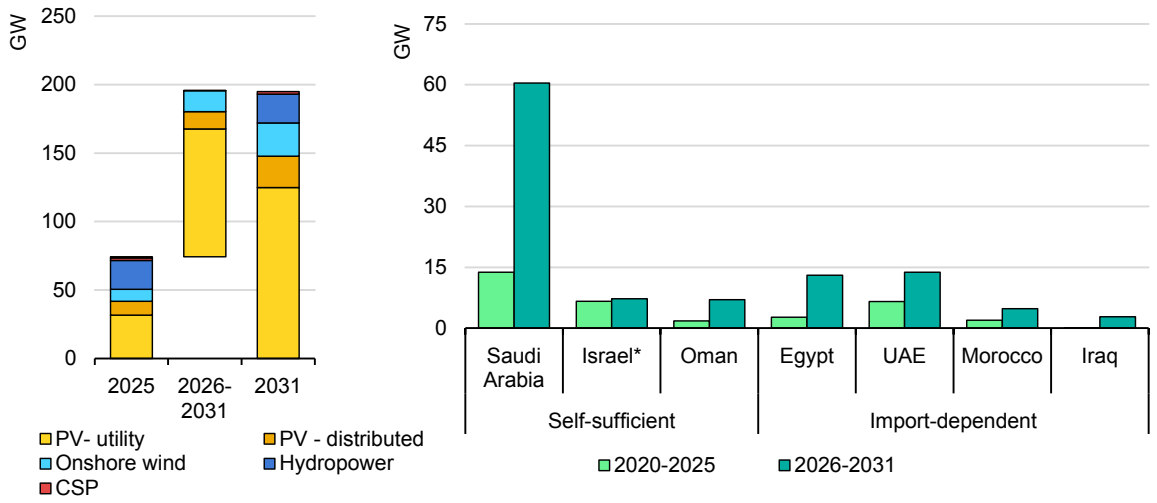
Renewable electricity capacity in the Middle East and North Africa (MENA) is forecast to more than double over the next six years, reaching almost 200 GW by 2031. The forecast is broadly unchanged from last year, with stronger corporate demand, project expansions and higher targets offsetting slower renewable hydrogen development and the impacts of near-term supply-chain and cost uncertainties linked to the closure of the Strait of Hormuz. These uncertainties may delay some planned projects but are not expected to weaken long-term ambitions or pipeline volumes.

Utility-scale solar PV leads renewable electricity growth in MENA, accounting for almost 80% of the 122 GW of capacity additions forecast for 2026-2031. Onshore wind contributes 13%, distributed solar PV 10%, and small additions from pumped-storage hydropower. By 2031, solar PV accounts for 75% of the region's installed renewable capacity, the highest share of any region globally. This reflects targeted procurement and favourable economics supported by excellent resources, economies of scale from large projects and, in some markets, favourable land and state-backed financing conditions.

Rapid economic and population growth is a major driver of renewable electricity deployment in the region, with additional power demand coming from cooling, desalination, data centres, and low-emissions aluminium, steel and fertiliser production. Several major power systems, including those of Saudi Arabia, Egypt, Morocco, and Algeria, have recently recorded peak loads, while Oman has raised its demand outlook amid rapid growth in industrial and commercial consumption.

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Renewable capacity additions in the Middle East and North Africa by technology in 2025 and 2031 (left) and for selected markets, 2026-2031 (right)



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*The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

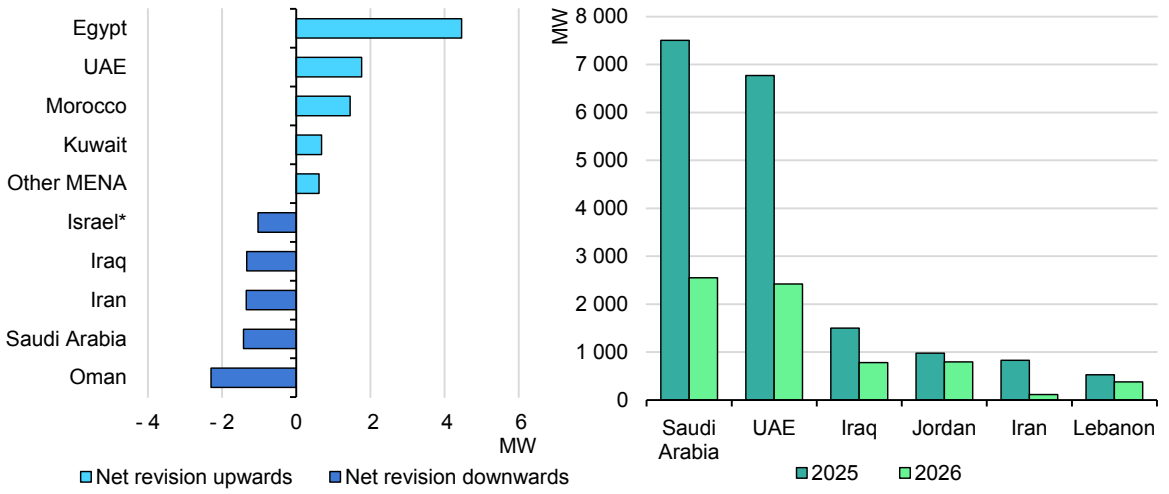
Notes: CSP = concentrated solar power. UAE = United Arab Emirates. Countries are classified as self-sufficient if they do not rely on oil and gas imports for power generation and import-dependent if they rely on oil and gas imports for power generation.

Energy security is another key growth driver, although motivations vary according to a country's access to fossil fuels. In hydrocarbon-producing countries that can meet their power generation needs with domestic fuels, renewables reduce domestic fuel consumption, freeing up supplies for export. These markets account for roughly 67% of forecast growth, led by Saudi Arabia, which provides half of the regional increase (60 GW). Its renewable electricity targets support the Liquid Displacement Programme, which aims to make 1 million barrels of oil per day available for export by reducing domestic consumption. A record 9 GW was added in 2025, raising Saudi Arabia's renewable electricity capacity to more than 14 GW. Similar drivers support expansion in other hydrocarbon-producing markets, including Oman.

Greater use of renewables also reduces import costs and exposure to price volatility and supply disruptions for hydrocarbon-importing countries – risks that the current conflict in the Middle East have further highlighted. Thus, around one-third of regional growth comes from countries that rely on fossil fuel imports for power generation, including Egypt and Tunisia, whose gas-fired power systems rely on imported gas; Morocco, which depends on coal and natural gas; and Iraq, where imported Iranian gas remains important for power generation. The United Arab Emirates is also a net gas importer despite being a major hydrocarbon producer.

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Renewable capacity forecast revisions for selected Middle East and North Africa markets, 2026-2030 (left) and Chinese solar PV module imports, Q1-3 2025 and 2026 (right)



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* The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

Notes: MENA = Middle East and North Africa. UAE = United Arab Emirates. Other MENA = Algeria, Bahrain, Lebanon, Libya, Jordan, Qatar, Syria, Tunisia, and Yemen.

Source: Right graph: Ember (2026), China's Solar PV Exports.

The regional forecast is broadly unchanged from last year, as upward revisions in some markets offset reductions elsewhere. Egypt records the largest increase, reflecting accelerated renewable capacity plans after the current conflict in the Middle East caused a sharp rise in gas import costs. In March 2026, the government reported that the country's monthly natural gas import bill had nearly tripled since the start of the conflict, from USD 560 million to USD 1.65 billion, and it moved its 45% renewable electricity target forward from 2035 to 2028. This acceleration builds on already-enacted reforms, including a new corporate PPA framework, the reintroduction of competitive wind and solar auctions, and a growing pipeline of large bilateral wind, solar and storage projects.

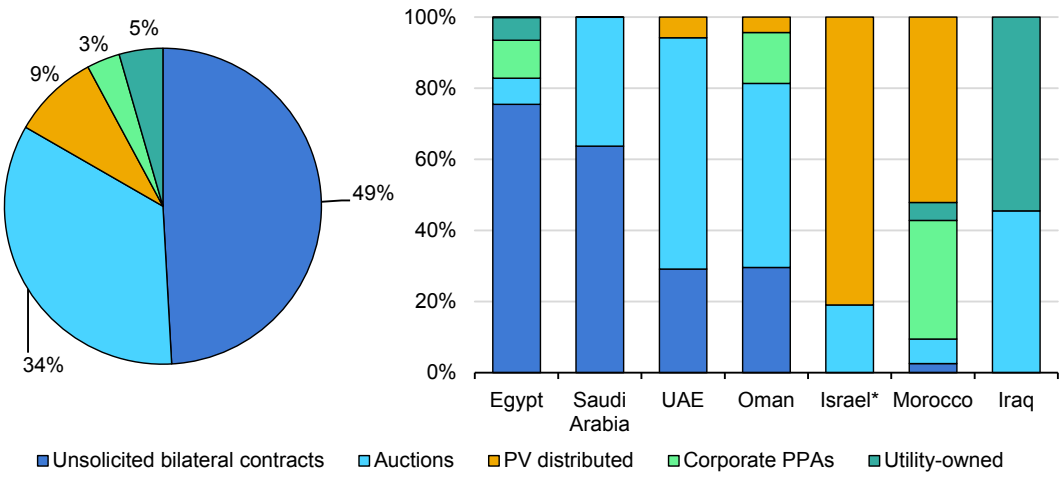
The outlook for the United Arab Emirates has also been revised upwards, reflecting its plans to expand the Mohammed bin Rashid Al Maktoum Solar Park from 5 GW to more than 7 GW and the more ambitious clean energy targets. In January 2026, the country raised its clean energy target to 35% by 2031, up from 32% in 2030. Morocco's forecast is similarly higher owing to a growing corporate PPA pipeline and faster-than-expected progress by OCP, the state-owned mining company, to realise its plan for more than 2 GW of renewable capacity, which supports its 2040 net zero target. Faster-than-expected growth in distributed solar PV for residential and off-grid applications in Syria also contributes to the upward revision. Unreliable electricity supply and high fuel costs have helped increase installed capacity from less than 500 MW in 2022 to over 2 GW in 2026.

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However, slower-than-anticipated project progress in several markets and risks to project pipelines from closure of the Strait of Hormuz offset these gains. Supply-chain disruptions could delay equipment deliveries and construction, while uncertainty over equipment and insurance costs could weaken project economics and postpone final investment decisions (FIDs). The combined Chinese solar module imports of Saudi Arabia, the United Arab Emirates, Iraq, Jordan, Iran and Lebanon fell 61% year-on-year in the first three quarters of 2026, raising uncertainty over project delivery timelines.

One developer also reported that several financial closes and project-agreement signings could be delayed by 6-12 months. The forecast is therefore revised downwards for countries where projects are already progressing more slowly (Saudi Arabia) and where a significant share of the project pipeline has yet to reach FID (Iran and Iraq).

Gross utility-scale renewable capacity additions by procurement type, 2026-2031 for MENA (left) and for selected countries (right)



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Notes: UAE = United Arab Emirates. PPA = power purchase agreement.

Oman's forecast has also been scaled back from last year's projections, mainly because of weaker prospects for renewable hydrogen. Two projects awarded in earlier hydrogen rounds were cancelled amid difficulties securing offtakers, while other awarded projects have yet to reach FID. Additionally, outlooks are lower for

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Libya and, to a lesser extent, Israel,[6] where missed 2025 and 2026 renewable energy targets indicate slower-than-expected progress in advancing planned projects.

Bilateral contracts between independent power producers and state-owned utilities are the main procurement route for renewable deployment in MENA, followed closely by competitive auctions. Together they account for over 80% of MENA's utility-scale renewable capacity growth. This mainly reflects Saudi Arabia's use of bilateral contracts sponsored by the Public Investment Fund (PIF), which cover 70% of the 130-GW 2030 target, with competitive procurements providing the remaining 30%.

Auctions remain the main procurement mechanism in the United Arab Emirates and Oman, and they have resumed in Egypt after a ten-year hiatus. Bilateral contracting is also gaining prominence, led by Egypt, while the United Arab Emirates and Oman have signed their first bilateral contracts for round-the-clock renewable power.

At the same time, direct corporate and industrial procurement is becoming an increasingly important source of renewable energy growth, particularly for low-emissions industrial production. In Egypt, exposure to the Carbon Border Adjustment Mechanism (CBAM) encourages aluminium, steel and silicon producers to procure their power supplies directly. In Morocco, most additions to the project pipeline stem from demand for industrial activities (notably OCP's plans to decarbonise its mining and fertiliser operations and produce renewable ammonia) and for desalination and cement production. Corporate procurement is also emerging in Oman to supply renewable electricity to the oil and gas sector.

In the accelerated case, renewable energy expansion could be almost 30% higher – reaching nearly 233 GW by 2031 – if key regulatory, grid and financing barriers are addressed. As renewable penetration rises, system integration becomes increasingly important: one developer cited commissioning delays and claims for curtailment compensation caused by grid constraints. Countries are responding with planned grid upgrades and interconnections; greater battery storage deployment (Saudi Arabia, the United Arab Emirates, Egypt, Morocco and Oman); pumped-storage capacity and pipelines (Morocco, the United Arab Emirates, Israel, Egypt and Oman); and round-the-clock hybrid renewable projects (the United Arab Emirates and Oman).

Delivering these investments on or ahead of schedule could accelerate progress in realising existing renewable energy targets. Distributed solar PV could also

[6] The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

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expand more quickly if tariff and remuneration frameworks balance attractive economics for self-consumers with adequate grid cost recovery, alongside lower electricity subsidies. Weak offtaker creditworthiness, inflation and currency depreciation remain constraints in some markets, but state-backed guarantees, concessional financing and favourable contract terms could improve project bankability and accelerate deployment.

The role of wind and solar PV in power systems

Key points

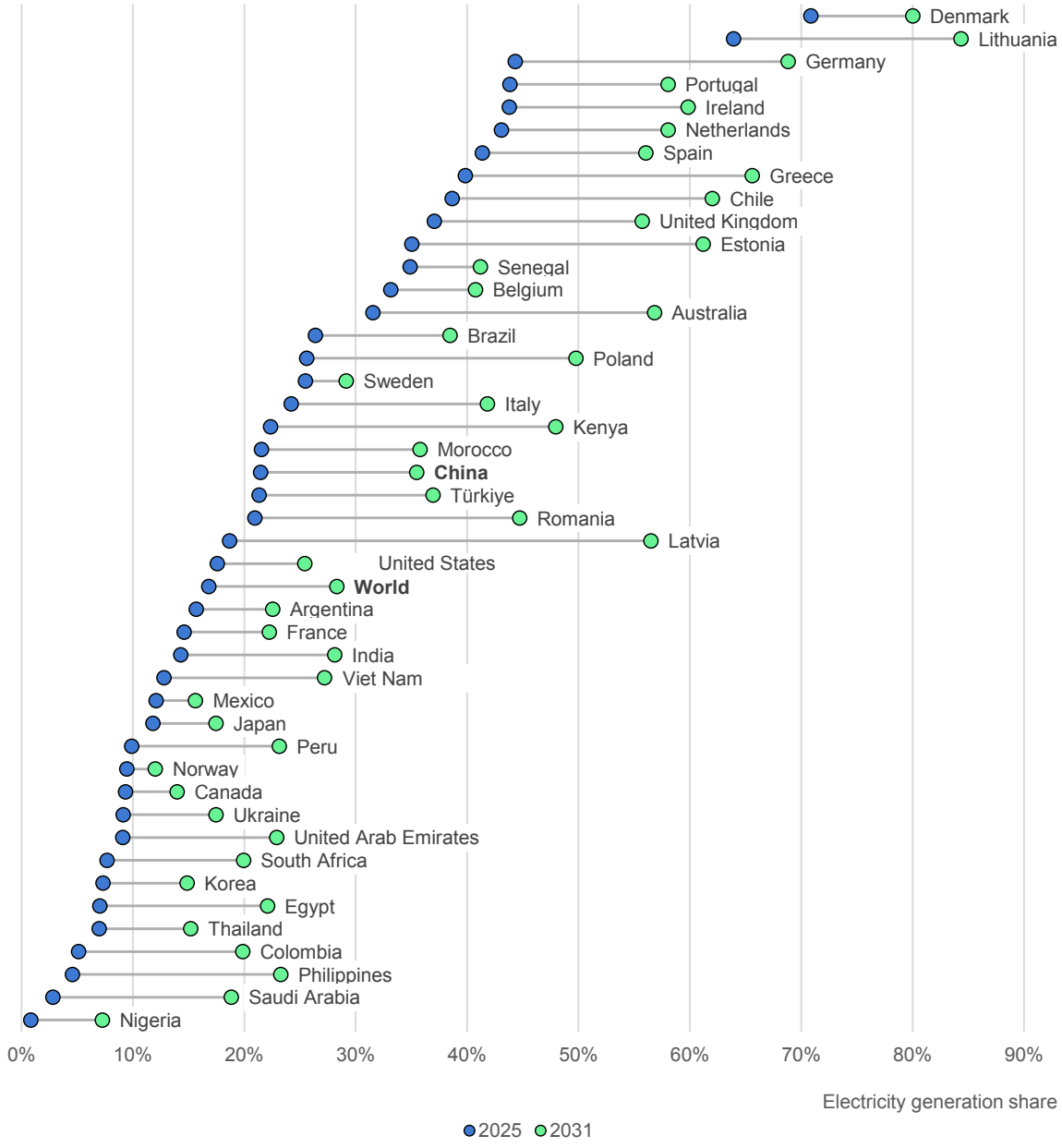
- Globally, the wind and solar PV share in power generation increases from 17% today to 28% in 2031. Solar PV alone doubles from 8% to nearly 16%, becoming the largest renewable energy source in 45 countries.
- In 2031, variable renewable energy (VRE) shares reach around 80% in Lithuania and Denmark, made up mostly of wind. In Australia, Chile, Estonia, Greece, Ireland, Latvia, the Netherlands, Portugal, Spain and the United Kingdom, VRE shares surpass 55%.
- Solar PV leadership becomes more geographically diverse, with Hungary generating more than 40% of its electricity from solar PV by 2031, while Lithuania leads global wind shares at 61%.
- Global wind and solar PV curtailment nearly doubled in both 2024 and 2025 to almost 200 TWh and is projected to exceed 850 TWh by 2031 without prompt investments in grids, storage and flexibility.

VRE shares in electricity generation increase in almost all major markets over the forecast period.

Globally, the share of electricity generation from solar PV and wind rises from around 17% in 2025 to almost 28% by 2031. Today solar PV is the largest renewable electricity source in 27 countries, and this number is expected to increase to 45 in 2031 to include China, the United States, Mexico and Türkiye. Solar PV overtakes wind in 2026 and hydropower in 2029 to become the largest renewable generation source. Its share in global power generation doubles to 16% by 2031.

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Variable renewable electricity generation shares for selected countries, 2025 and 2031



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Notes: Variable renewables include solar PV, onshore wind and offshore wind. Renewable generation projections incorporate technical curtailment assumptions and average weather.

Source: Total electricity generation from IEA (forthcoming), Electricity 2027.

While Denmark remains the leader in 2025 with a 71% share of electricity generation from wind and solar PV, Lithuania overtakes all other countries by 2031, reaching 84%, followed by Denmark at around 80%. Germany also nears 70%, while a broader group including Australia, Chile, Estonia, Greece, Ireland, Latvia, the Netherlands, Portugal, Spain and the United Kingdom surpass 55%.

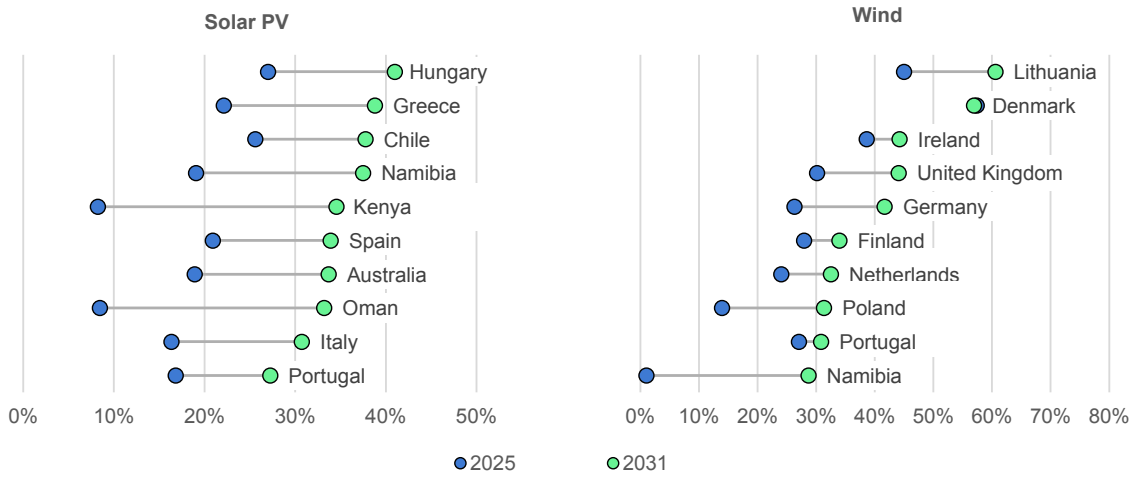
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The main increases are concentrated in Europe. Latvia adds around 38 percentage points to reach 56% by 2031, followed by Estonia (+26 percentage points), Greece (+26 percentage points), Germany (+25 percentage points), Poland (+24 percentage points) and Romania (+24 percentage points). Outside of Europe, substantial growth also occurs in Chile (+23 percentage points) and Australia (+25 percentage points), while VRE shares nearly double in China (to 35%) and India (to 28%).

By technology, renewable-generation leaders show variability. For solar PV, Hungary is projected to have the highest share of electricity generation in 2031, at 41%, followed by Greece at 39% and Chile at 38%. Nine of the selected markets exceed 30%, with particularly rapid growth in Oman and Kenya. Both start from a solar generation share of around 8% in 2025, with Oman rising to 33% and Kenya to 35%. Bulgaria also more than doubles its share from 16% to 36%.

The highest wind shares remain concentrated in northern Europe. Lithuania is projected to have the largest share globally (61%) in 2031, followed by Denmark at 57%. Ireland, the United Kingdom, and Germany all surpass 40%, while Estonia, Finland, Luxembourg, the Netherlands and Poland each exceed 30%. In Denmark, offshore wind overtakes onshore wind during the forecast period.

Top 10 countries by generation share of solar PV and wind by 2031



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Source: Total electricity generation from IEA (forthcoming), Electricity 2027.

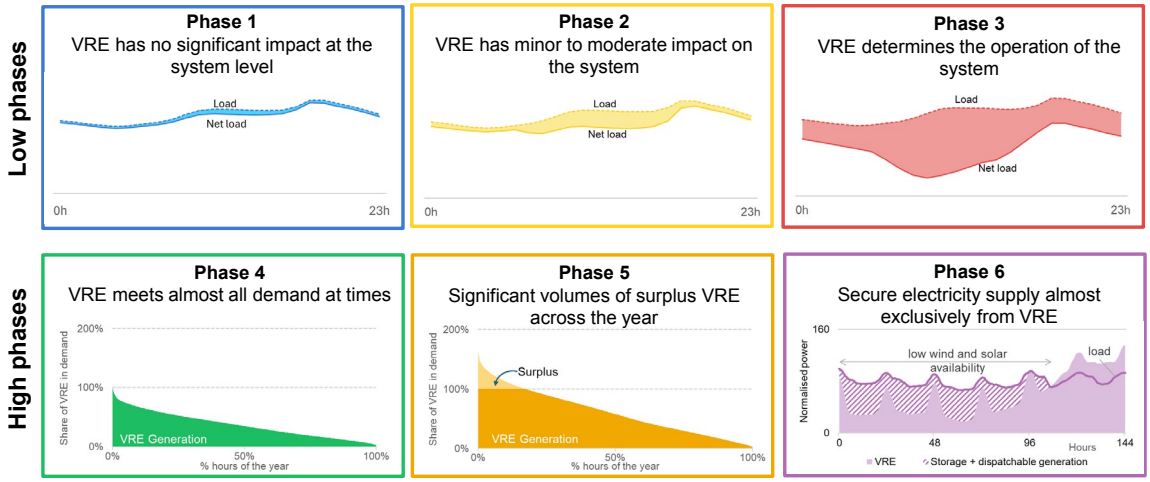
Countries move towards advanced VRE integration by 2031

The IEA classifies VRE integration into six phases, each reflecting a progressively greater influence of solar PV and wind generation on electricity system operations. In the lower phases (1-3), VRE has a relatively limited impact on system

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performance, and integration challenges can largely be managed through incremental adjustments to existing assets and operational practices. In the higher phases (4-6), however, VRE increasingly shapes system operations, leading to more frequent periods of surplus generation, reduced utilisation of conventional power plants and a growing need for flexibility resources. As a result, power systems must undergo substantial changes in their design, operation and investment strategies to accommodate high shares of variable renewables.

IEA VRE integration framework phases



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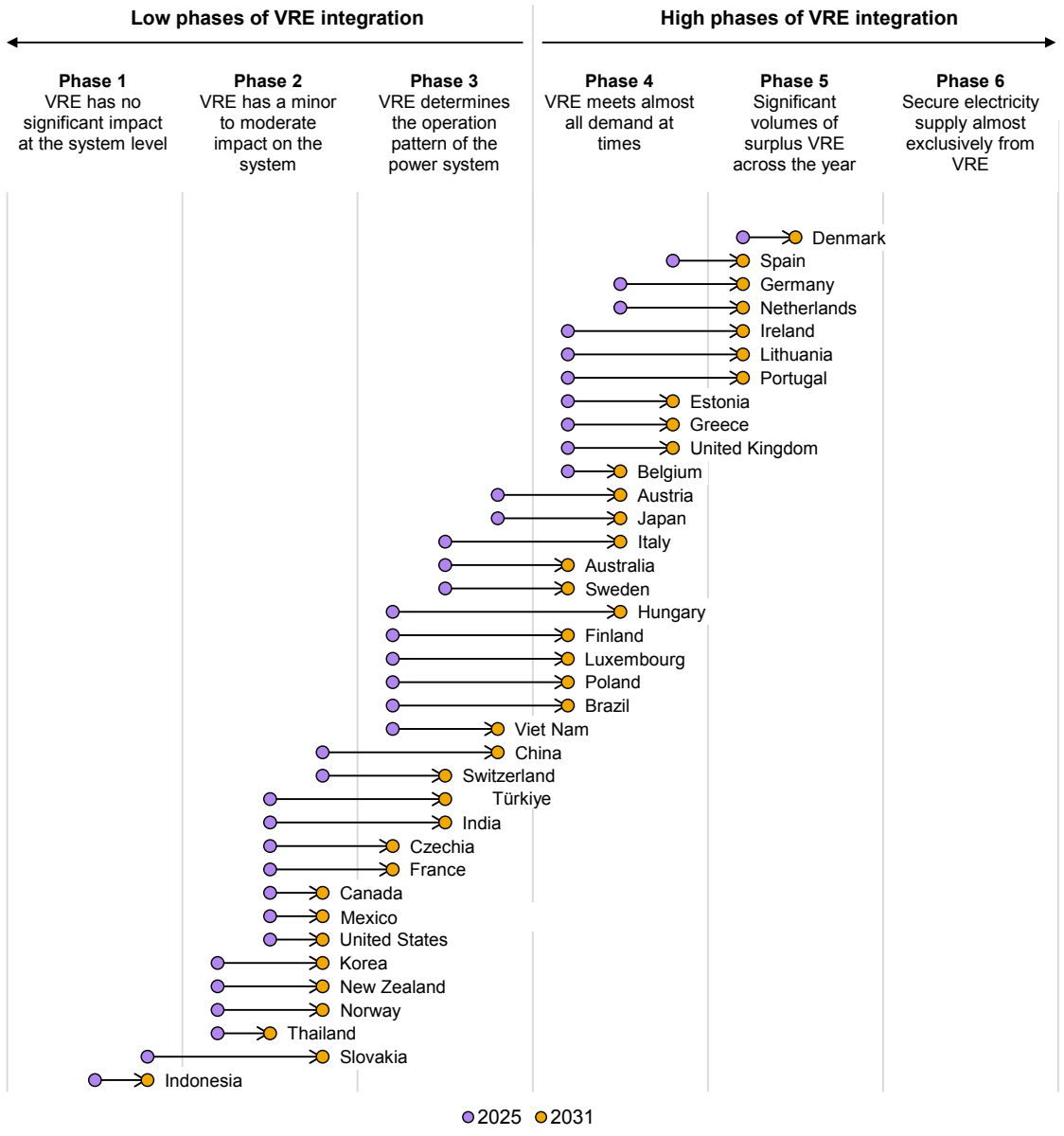
Notes: VRE = variable renewable energy. VRE includes solar PV and wind.
Source: IEA (2024), Integrating Solar and Wind.

The latest IEA assessment indicates a broad shift towards more advanced VRE integration phases between 2025 and 2031. In 2025, 26 of the 37 assessed countries remained in the lower integration phases (1-3), while 11 had reached the higher ones (4-6). By 2031, 21 countries are projected to be in the higher phases, compared with 16 remaining at the lower levels. The number of countries reaching Phase 5 or above increases from one to seven, reflecting the growing impact of solar PV and wind on power system operations, planning and flexibility.

Although VRE shares strongly influence integration phase, penetration alone does not determine phase assignment. Assessments also consider the generation mix, demand alignment, system flexibility, frequency and inertia management, and the timing of VRE surpluses and deficits. As a result, countries with similar VRE shares can have different integration challenges. Solar-dominated systems generally require greater operational flexibility because of concentrated midday generation and steeper ramping requirements, while wind-based systems tend to experience more gradual variations in output.

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VRE integration phases for selected countries, 2025 and 2031



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Denmark remains the only country in Phase 5 in 2025, with VRE supplying around 70% of electricity generation and wind accounting for most of the output. By 2031, Lithuania is projected to join Denmark in Phase 5 as its VRE shares increase substantially, making up more than 80% of generation in both countries. While solar PV deployment accelerates, all three systems continue to be characterised by a predominantly wind-based VRE mix.

Ireland, Germany, the Netherlands, Spain and Portugal are also projected to reach Phase 5 by 2031 as VRE shares continue to increase. Although the contribution of solar PV and wind varies across these countries, all are expected to experience

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more frequent periods of high VRE output and growing challenges associated with managing surplus generation. In Germany and the Netherlands, wind remains the largest source of VRE generation, while Spain and Portugal exhibit a more balanced mix, with solar PV accounting for an increasing share of growth.

China and India continue progressing through the VRE integration framework as solar PV and wind deployment expands rapidly. China advances further within Phase 3, with VRE shares increasing from around 20% in 2025 to more than one-third of generation by 2031. India moves from Phase 2 to Phase 3 over the same period as its VRE share rises to more than one-quarter of electricity generation. In both countries, solar PV accounts for the majority of future VRE growth, highlighting its increasing role in shaping power system operations and flexibility requirements.

Curtailment rises in key markets as rapid wind and solar PV expansion outpaces grid and flexibility investments

With rapid solar PV and wind expansion, curtailment is increasing in a growing number of markets. While some level of curtailment is economically efficient and expected in power systems with high shares of variable renewables, rapid increases often indicate insufficient grid capacity, flexibility or system integration measures. Addressing these challenges requires investment in transmission, storage and system flexibility alongside improved system planning.

The amount of curtailed wind and solar PV generation in major markets has increased rapidly in recent years. Total technical curtailment volumes almost doubled in 2024 and again in 2025, reaching nearly 200 TWh globally. In 2025 alone, at least 88 TWh of solar PV generation and a similar volume of onshore wind generation were curtailed, together with more than 10 TWh of offshore wind. China accounted for the majority, with more than 60 TWh of curtailed solar PV generation and around 60 TWh of onshore wind.

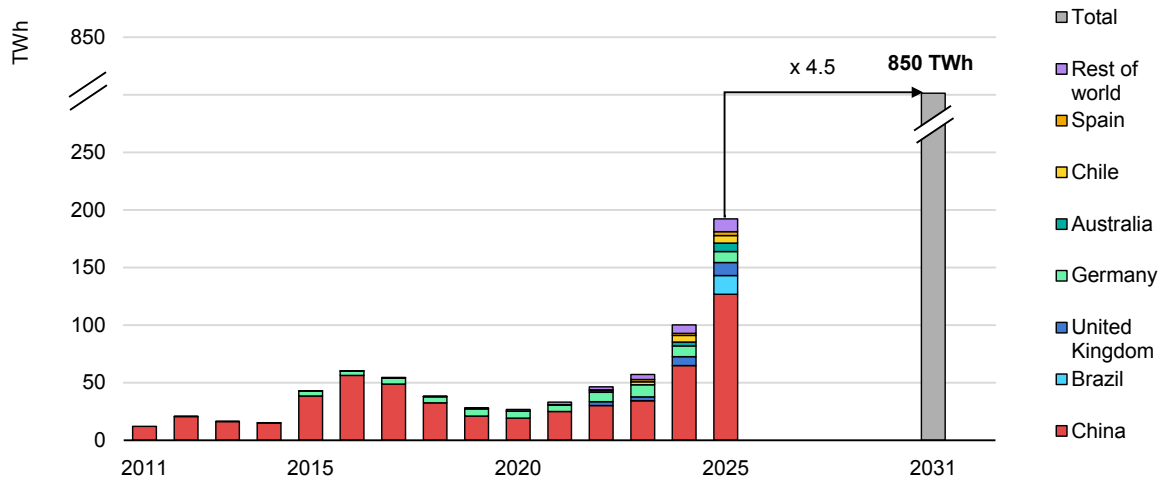
Despite this sharp increase, curtailment remains relatively limited compared with the scale of renewable generation. In large markets, combined curtailed wind and solar PV generation accounted for less than 5% of total generation in 2025, although the curtailment rate has more than doubled since 2023. This highlights both the growing challenges of integrating rapidly expanding variable renewable capacity and the progress made in deploying grid infrastructure, storage and other flexibility resources to absorb higher renewable generation shares.

Although the main case assumes continued investment in electricity networks, storage and flexibility, annual wind and solar PV curtailment is projected to increase almost fivefold by 2031 as variable renewable

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generation expands. However, eliminating all curtailment would not always be economically efficient, as the investment required may exceed the cost savings in some cases. Continued investment in networks, storage and flexibility, along with reforms to power markets, project siting and system operation, can limit curtailment to economically efficient levels while enabling higher VRE generation shares.

Wind and solar PV generation curtailed per region, 2011-2031



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Curtailment rates for solar PV and onshore wind remained in the low single digits in many large markets in 2025, although several systems recorded double-digit rates. Patterns differed by technology and country, reflecting the location and pace of deployment, network capacity and interconnections, operational constraints, demand-side flexibility and market design.

China illustrates not only how curtailment can be reduced, but also how quickly it can re-emerge when deployment outpaces grid expansion. Solar PV curtailment exceeded 10% in the mid-2010s but had fallen below 2% by the early 2020s owing to restrictions on new development in the most affected regions as well as a shift towards distributed PV, transmission expansion, improved interprovincial power trading and stronger system flexibility. Wind power followed a similar pattern, with curtailment peaking at around 17% in 2012 and again in 2016 before declining to about 3% in 2020-21.

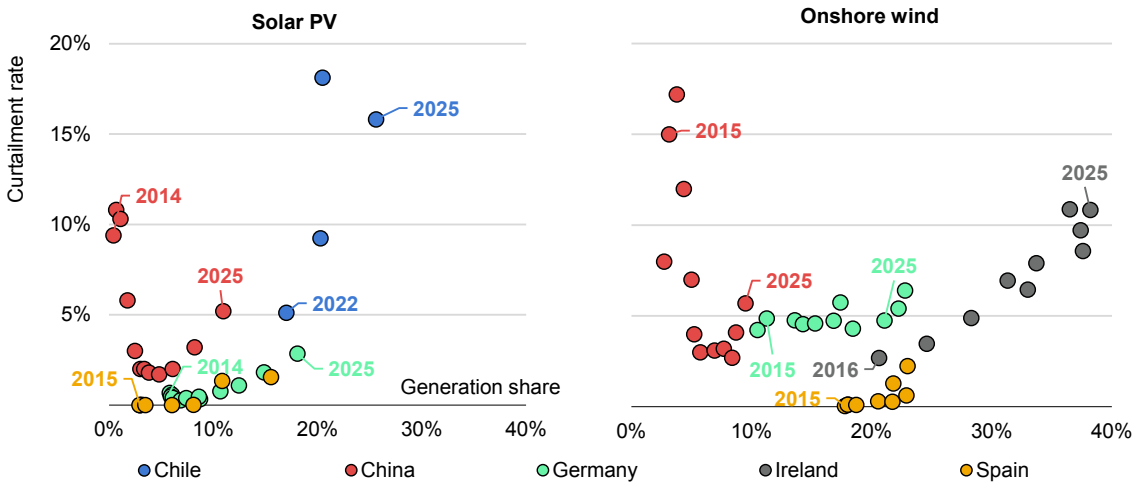
However, rapid capacity growth has renewed integration challenges. Solar PV curtailment rose to 3.2% in 2024 and 5% in 2025, while wind curtailment climbed back to 6% as additions again outpaced grid reinforcement in some regions.

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Recent reforms allowing selected provinces to relax renewable utilisation targets have facilitated continued deployment, but do not address underlying grid constraints.

Further transmission investment, storage deployment, interprovincial exchanges and demand-side flexibility will be critical to limit curtailment as renewable penetration continues to rise. In parallel, recent reforms have increased the allowable renewable curtailment threshold from 5% to 10% in selected provinces, providing grid operators with greater flexibility to accommodate rapid renewable energy deployment.

Technical curtailment rates and shares of electricity generation for solar PV and onshore wind in selected countries



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Notes: Each dot represents one year. Data points indicate officially reported curtailed or constrained energy generation and combine various schemes, depending on the country. Technical curtailment is the dispatching-down of renewable energy for network or system reasons; energy that has been dispatched-down due to economic or market conditions is not included.

Sources: IEA analysis based on data from Coordinador Eléctrico Nacional de Chile (CEN), Reducciones de energía eólica y solar en el SEN (multiple releases); National Bureau of Statistics of China (NBS), China Energy Datasheet 2000-2025; Bundesnetzagentur, Monitoring Report (multiple releases); EirGrid, Renewable Dispatch-Down (Constraint and Curtailment) reports (multiple releases); Red Eléctrica de España (REE), I3DIA (multiple releases); and Sistema de Información del Operador del Sistema (e·sios).

Chile demonstrates how quickly curtailment can rise when generation-rich regions are far from demand centres with transmission constraints. Solar PV curtailment increased from nearly 5% in 2022 to around 18% in 2024 and remained close to that level in 2025. Rapid battery deployment and the planned 3-GW Kimal-Lo Aguirre high-voltage direct current (HVDC) line are expected to ease these constraints and increase system flexibility.

By contrast, Germany has maintained relatively low solar PV curtailment despite its large and rapidly growing fleet. Curtailment remained below 1% until 2021 and rose to only around 3% in 2025, thanks to a highly interconnected

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network, redispatch measures and continued grid reinforcement. However, the increasing frequency of negative electricity prices and rapidly rising balancing costs highlight the growing need for additional storage and demand-side flexibility.

For offshore wind, however, Germany recorded the highest curtailment rate of all major markets, even though it declined from around 19% in 2023 to 11% in 2025. Transmission bottlenecks between northern generation centres and southern demand regions remain the primary challenge, highlighting the importance of timely completion of major transmission projects such as SuedLink. The lower curtailment rate for solar PV also reflects the more distributed nature of Germany's solar fleet, with generation often located closer to demand centres and therefore less exposed to the transmission bottlenecks that constrain remote utility-scale generation.

In the United Kingdom, transmission congestion remains the main integration challenge. Around 11 TWh of wind generation was curtailed in 2025, largely due to insufficient connection capacity between Scotland and demand centres in southern Great Britain. Accelerated transmission expansion and connection queue reforms are expected to improve system integration.

In Spain, VRE curtailment increased rapidly from low levels in 2022 to around 4% in 2025 but were still lower than for other large EU markets with high VRE penetration. Growing midday surpluses, limited interconnection capacity and more conservative system operation contributed to higher curtailment. Battery deployment, transmission expansion and the Bay of Biscay interconnector are expected to alleviate these pressures.

Ireland illustrates the challenges of integrating high shares of variable renewables in a relatively isolated system. Planned grid upgrades, higher non-synchronous penetration limits and expanded interconnections are expected to reduce these constraints.

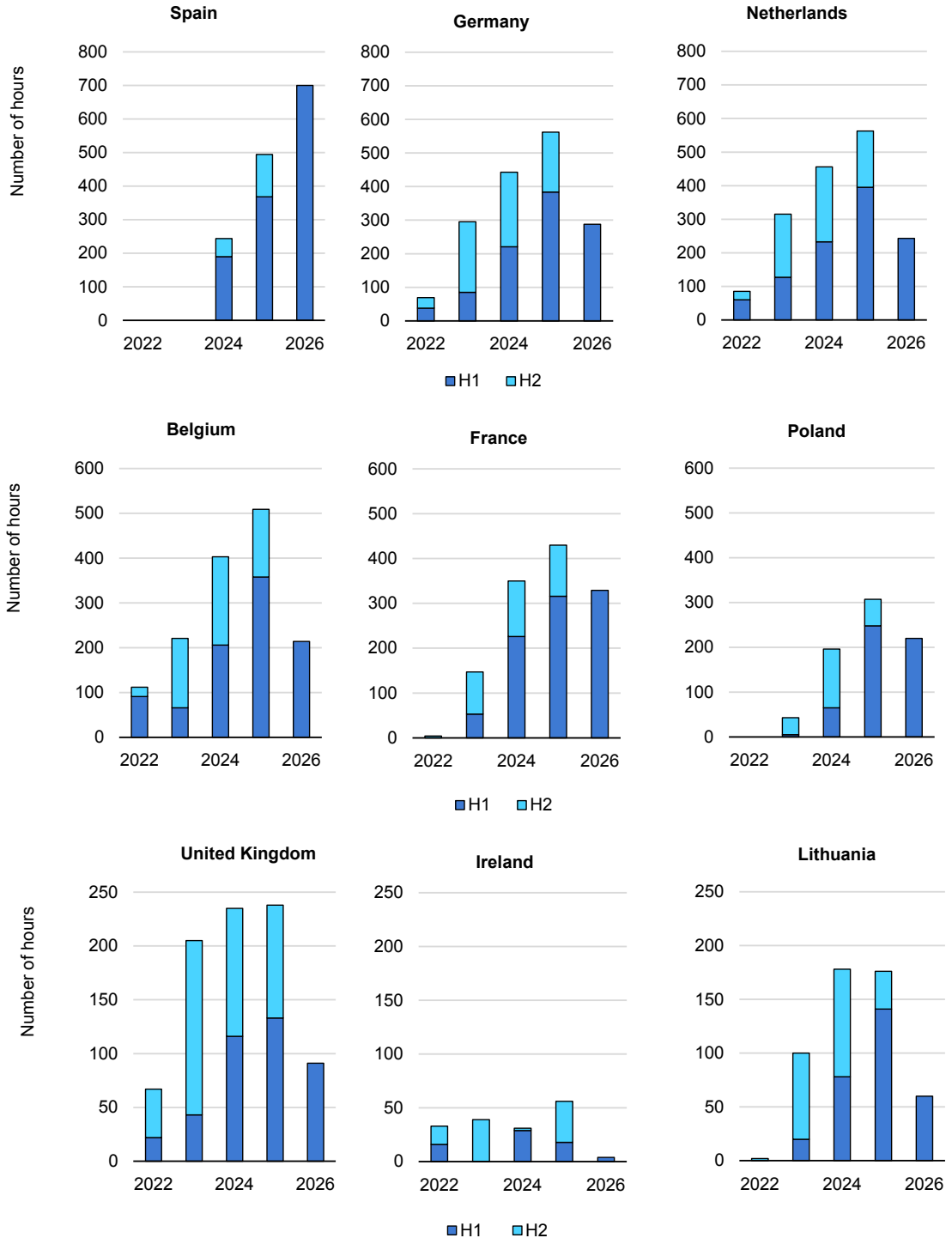
Rising negative-price recurrence underscores the need for greater power system flexibility

The frequency of negative electricity prices has risen sharply across European power markets since 2022, reflecting growing technical, regulatory and contractual inflexibilities.

Germany, the Netherlands and Belgium recorded the highest number of negative-price hours in 2025, each exceeding 500, while France, Poland and Lithuania also experienced strong increases from relatively low levels just a few years earlier. This trend indicates that negative prices are no longer confined to a few isolated events but are becoming a more frequent feature of electricity markets with high shares of variable renewable generation.

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Number of negative-price hours for selected European countries, 2022-2026



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Notes: Since 1 October 2025, EU Single Day-Ahead Coupling (SDAC) markets have been using 15-minute prices instead of hourly prices. From this date, elements in this chart are calculated as the average of the four 15-minute prices to ensure consistency over time.

In Spain, negative prices were not allowed until mid-2021. Even as renewable electricity shares were expanding, the market design set the floor at zero. After

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recording virtually no negative-price hours in 2022 and 2023, the frequency rose to 244 hours in 2024 and 494 hours in 2025. In the first half of 2026 alone, Spain had already recorded 700 negative-price hours, surpassing the full-year total for 2025.

While 2026 values for most countries should be interpreted cautiously because only H1 data are available, the results point to a continued increase in negative-price occurrences and underline the growing need for greater system flexibility, storage, demand-side response and grid integration.

Favourable weather conditions and lower curtailment could help several major markets realise much higher renewable electricity generation without additional capacity

Renewable electricity generation is determined by resource availability and, increasingly, by the ability of power systems to integrate variable renewables. Grid constraints and curtailment are becoming more important determinants of capacity factors as renewable penetration rises. Technical curtailment resulting from network limitations is becoming more common, while low or negative wholesale prices can also lead generators to reduce output for economic reasons.

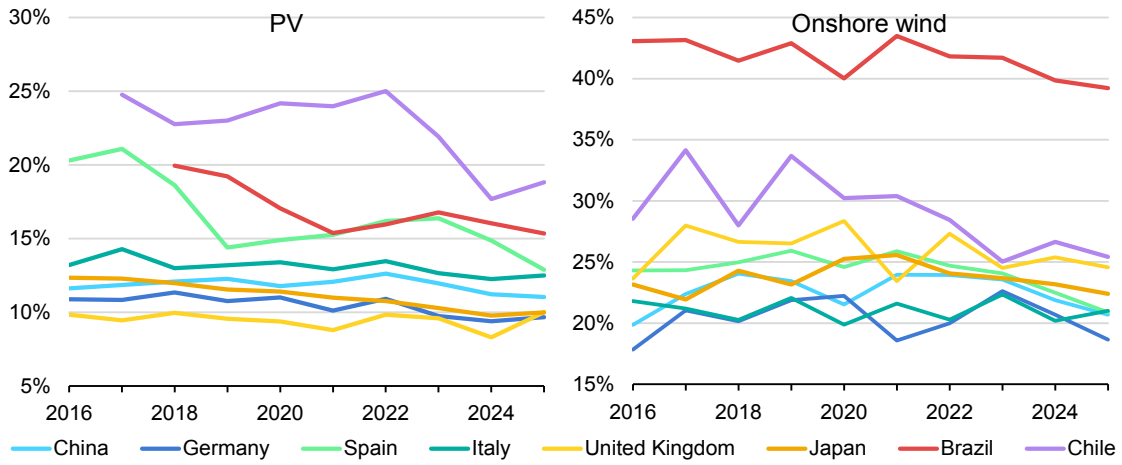
The main-case generation forecast reflects recent trends in grid constraints, market conditions and the geographical distribution of renewable capacity. As the best resource sites become increasingly saturated in many mature markets, new projects are increasingly being developed in locations with lower solar irradiation and weaker wind resources, reducing average fleet capacity factors. Rising curtailment is also becoming an increasingly important factor.

During 2024-2026, solar PV and wind curtailment increased sharply in several markets with high shares of variable renewables, lowering fleet-wide capacity factors despite continued technology improvements and accelerating battery storage deployment. The effect has been most pronounced for solar PV. Over the past three years, average solar PV capacity factors in Chile were more than 30% lower than in 2016-2018, compared with declines of around 25% in Spain, 18% in Japan and 13% in Germany.

A similar trend is evident for onshore wind, although it is less pronounced. Wind generation is typically more geographically and temporally diversified than solar PV, reducing the frequency of simultaneous surplus generation. At the same time, the deployment of larger and more productive turbines has partly offset the impact of rising curtailment and weaker resource quality by increasing average project output.

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Solar PV and onshore wind capacity utilisation factors, 2016-2025



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To assess the potential impact of this variability, renewable electricity generation in 2031 under the main-case forecast was compared with a sensitivity analysis assuming capacity factors equal to the 90th percentile of historical observations over the past ten years. This analysis illustrates the potential upside in renewable electricity generation that could be achieved under more favourable resource conditions and lower curtailment, without requiring additional generation capacity.

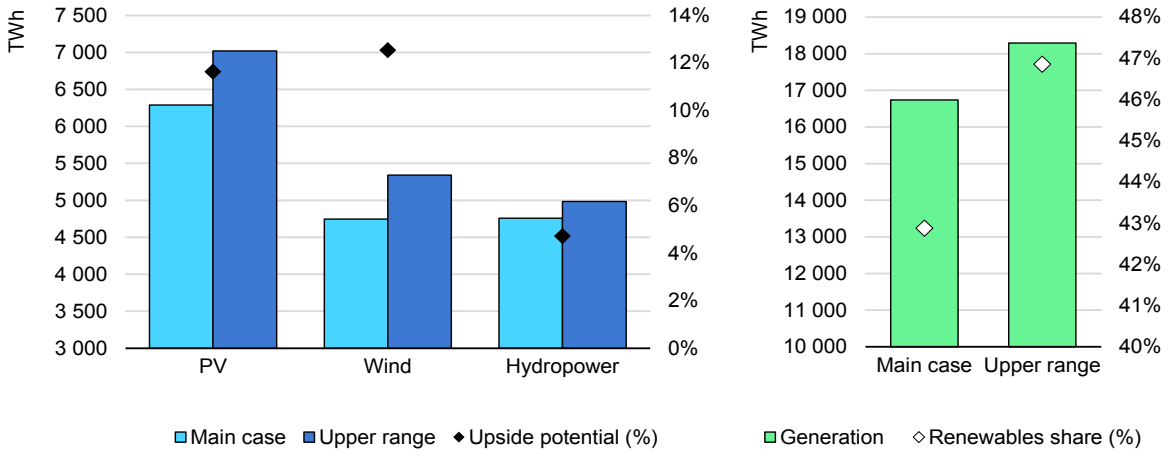
The upper-range capacity factor sensitivity analysis under more favourable renewable resource conditions and lower curtailment indicates that global renewable electricity generation in 2031 could be over 1 550 TWh, or 9% higher than in the main case. As a result, renewables could account for almost 47% of global electricity generation in 2031, compared with 43% in the main case.

Wind power offers the largest relative upside, with generation approximately 13% higher than in the main case, reflecting both the inherent variability of wind resources and the impact of rising curtailment in some major markets. Conventional hydropower also exhibits significant upside potential due to interannual variations in precipitation, snowmelt and reservoir inflows.

Solar PV offers generation upside comparable to wind despite much lower variability in annual solar irradiation. This reflects the increasing role of curtailment in markets with high solar penetration, as well as the deployment of new capacity in areas with lower resource quality and greater system integration challenges. Historical capacity factors cover periods with lower curtailment than assumed in the forecast, suggesting that faster investment in transmission infrastructure, battery storage and demand-side flexibility could unlock a substantial share of this additional generation potential without further capacity additions.

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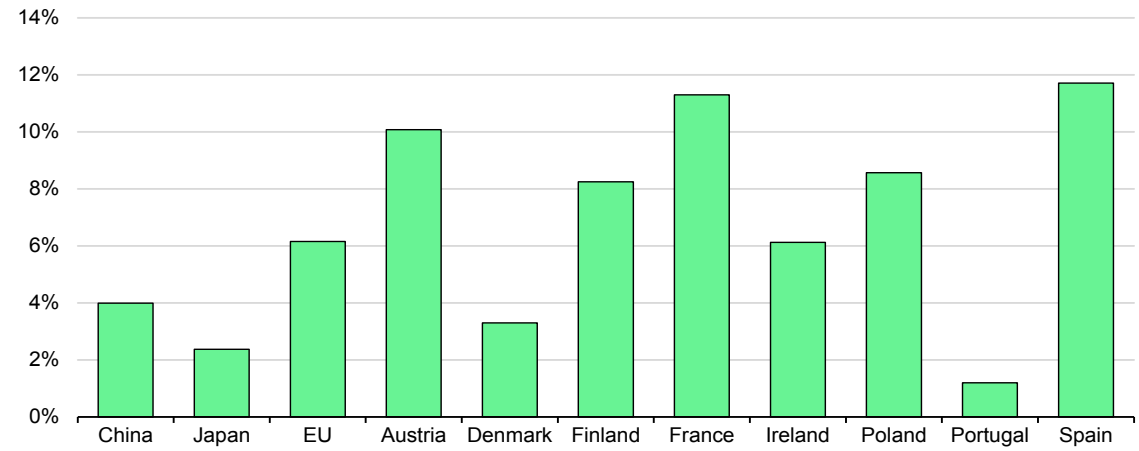
Renewable electricity generation in the main case forecast and assuming upper range of historical capacity factors, 2031



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Favourable resource conditions and improved system integration can provide an important margin for achieving renewable electricity targets. While weather conditions cannot be controlled, countries can increase renewable electricity output from existing assets by reducing curtailment through greater grid capacity, storage and system flexibility. In the European Union, renewable electricity generation in the main case remains roughly 5% below the level implied by 2030 ambitions. However, under favourable wind and hydrological conditions and with lower curtailment, renewable generation could exceed this level by a similar margin. This suggests that maximising the output of existing renewable assets can be as important as deploying new capacity for achieving renewable electricity targets.

Renewable electricity generation in main case forecast and using upper range of historical capacity factors, relative to country ambitions, 2030



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Note: EU = European Union.

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The contribution of favourable conditions and improved system integration differs across EU member states. In wind-dominated markets such as Denmark, stronger wind conditions can provide a significant boost to renewable generation, while in countries facing increasing curtailment, such as Spain and Germany, greater grid capacity, storage and flexibility can unlock additional output from existing assets. As renewable penetration rises across Europe, reducing curtailment is becoming an increasingly important complement to new capacity deployment for achieving renewable electricity targets.

Hybrid renewable power systems

Key points

- Hybrid solar PV, onshore wind and storage projects can deliver levelised electricity generation costs of less than USD 75/MWh in many regions, especially where solar and wind profiles are complementary.
- Hybrid project outputs and costs vary widely across regions, with China among the lowest-cost markets and ASEAN among the highest.
- Twofold solar PV and wind capacity overbuild can meet around 55% of annual baseload demand in many favourable locations before storage becomes necessary.
- Battery storage is key to raising demand fulfilment to 90%. Adding strict monthly and peak-delivery requirements raises the levelised cost of electricity (LCOE) by USD 30/MWh relative to moderate annual-only requirements in most modelled locations.
- Higher combined annual, monthly and daily peak demand-fulfilment requirements generally necessitate solar PV and wind capacity of around 2.5 to 3 times demand, about four hours of battery storage, and surplus generation of roughly 30%.

Can hybrid solar PV, wind and battery storage systems provide affordable baseload power?

In many regions, hybrid solar PV-wind-battery systems can supply affordable baseload power, but their economics depend strongly on local resource conditions and investment costs. The lowest-cost systems are found in locations where strong and seasonally diverse wind resources complement high solar irradiation, reducing the need for battery storage and lowering overall generation costs.

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In favourable regions such as parts of Australia, China, North America, North Africa, Arabian Peninsula and southern Africa or South America, optimised hybrid systems can deliver high levels of demand fulfilment at generation costs below USD 75/MWh. By contrast, regions with weaker solar and wind resources or stronger seasonal variability require greater capacity overbuild and storage, resulting in significantly higher costs.

IEA optimal firm renewable power dispatch modelling

The IEA conducted an optimisation simulation to identify the lowest levelised cost of electricity for a hybrid project combining solar PV, onshore wind and battery storage. The analysis is based on actual weather data and calculates hourly generation and energy storage charge/dispatch for various combinations of annual, monthly and peak-hour (6 hours per day) demand fulfilment criteria. Demand is represented as round-the-clock baseload that remains unchanged throughout all hours of the year when the hybrid system needs to provide electricity. The analysis applies demand fulfilment requirements for annual, monthly and peak-demand periods to reflect the time-sensitive value of electricity supply.

Based on requirements used in renewable energy auctions in India, the world's largest hybrid auction market, two cases were developed to assess the cost of meeting different demand profiles. The model runs independently for each point along a grid mesh consisting of latitude and longitude integer pairs and finds the least-cost hybrid solution for regional weather patterns. During the simulation, the hybrid project's storage system can be charged only from coupled renewable generation assets, meaning that charging the battery from the grid is not allowed.

Electricity that is surplus to load and storage requirements is not financially valued. Unused energy may be utilised, sold at opportunity cost or curtailed if renewable generation exceeds export or storage capacity, in line with operational constraints. Financial and technical assumptions are based on current IEA long-term modelling and expressed in real terms aligned with the 2025 weather year. Financial calculations are valid on a project level, and grid-related system costs are not included. The optimisation is performed separately for each of the five most recent weather years, to account for weather variability. All reported cost and performance metrics are taken from the weather year with the median levelised cost of electricity outcome.

When appropriately sized and operated, combinations of variable renewable energy sources and battery storage can improve the dispatchability and system value of renewable generation at costs that are increasingly comparable with

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conventional technologies. By reducing short-term variability in wind and solar output and shifting generation to periods of higher demand, hybrid projects can better align electricity supply with load profiles, including during peak hours. This can increase capture prices by reducing exposure to periods of surplus generation and low market prices, while providing greater value to power systems through enhanced flexibility and more predictable output. This section summarises the latest IEA modelling for hybrid solar PV, wind and battery systems. Falling battery-storage costs are reducing the lifetime cost of generating electricity using hybrid solar, wind and storage systems. At the same time, growing demand for firm low-emissions power from large electricity consumers, including data centres, is further strengthening the business case for hybrid systems. Nevertheless, meeting procurement schemes' most stringent delivery requirements (e.g. high annual, monthly and peak-period coverage thresholds) still requires substantial overbuilding of solar PV and wind capacity.

As a result, significant surplus generation can occur during periods of high renewable output. While battery storage can effectively manage daily variability, it is generally less suited to smoothing seasonal fluctuations, which may require longer-duration storage technologies or complementary flexibility resources.

Under a relatively loose annual demand fulfilment requirement of 70%, low-cost hybrid systems with generation costs below USD 75/MWh are available across all continents, with conditions being particularly favourable in Australia, Arabian Peninsula, India, North America, North Africa, southern Africa, and the lowland plains of Eurasia and South America. As delivery requirements become more stringent (annual 80%, monthly 75% and peak 90%), these low-cost areas become more concentrated and generation costs increase towards USD 75/MWh.

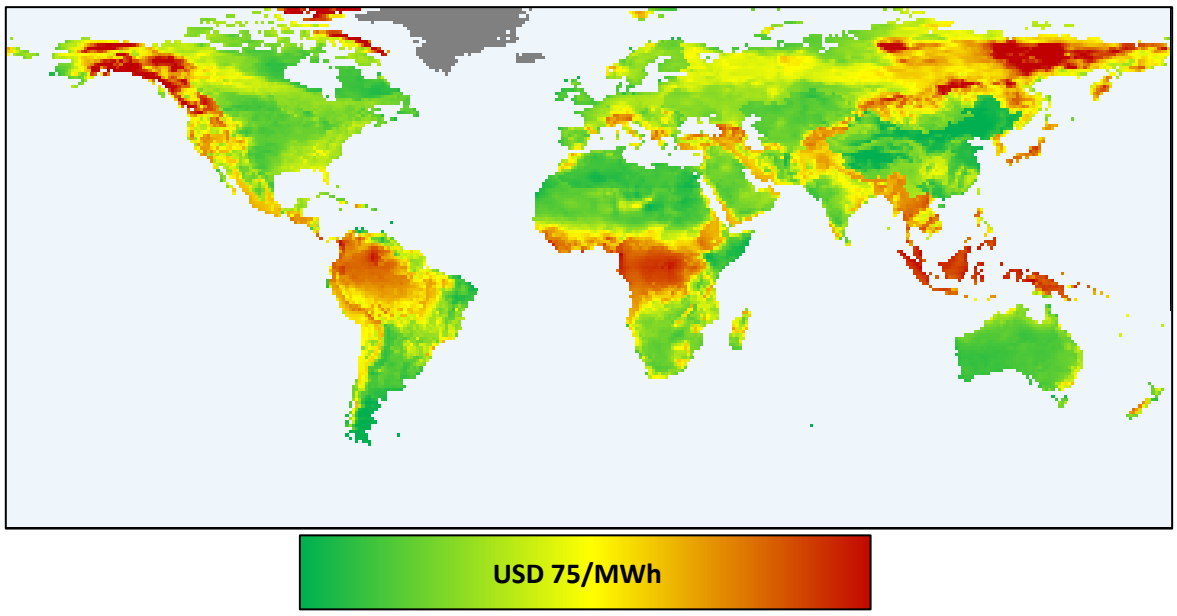
The impact is most pronounced in Europe and Eurasia, where stronger seasonal variability increases storage requirements. During prolonged periods of low solar and wind output, longer-duration storage solutions (e.g. pumped hydro, with sufficient storage capacity) can complement hybrid systems and cover the remaining demand gap.

The business case for hybrid projects is most attractive in regions that can pair low investment costs with strong solar resources and complementary wind profiles. For instance, the European Union and India provide contrasting examples of how seasonal wind and solar generation profiles influence hybrid system design. In the European Union, wind and solar PV exhibit a high degree of seasonal complementarity. Wind generation is strongest during the winter months when solar output is lower, while solar PV generation peaks in the summer when wind generation declines. As a result, the combined output of wind and solar remains relatively stable throughout the year, reducing seasonal variability and limiting periods of prolonged low renewable generation.

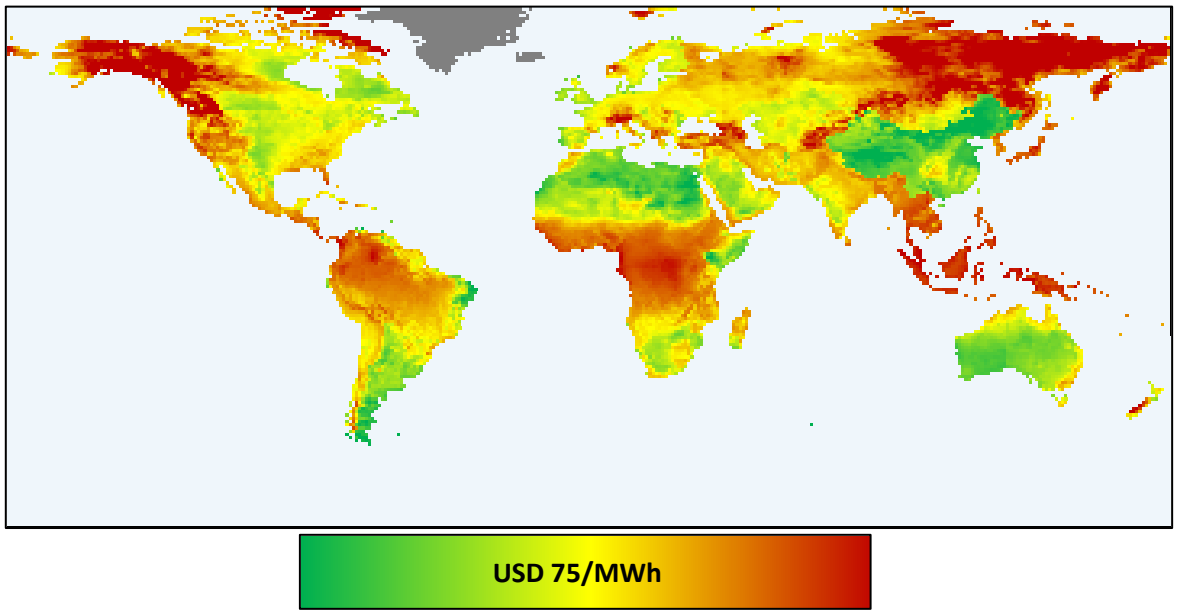
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Heatmap representations of LCOEs for hybrid renewable projects (solar PV, onshore wind and BESS) supplying round-the-clock demand, 2025

Case 1: Demand fulfilment requirements: annual 70%/monthly 0%/peak 0%



Case 2: Demand fulfilment requirements: annual 80%/monthly 75% / peak 90%



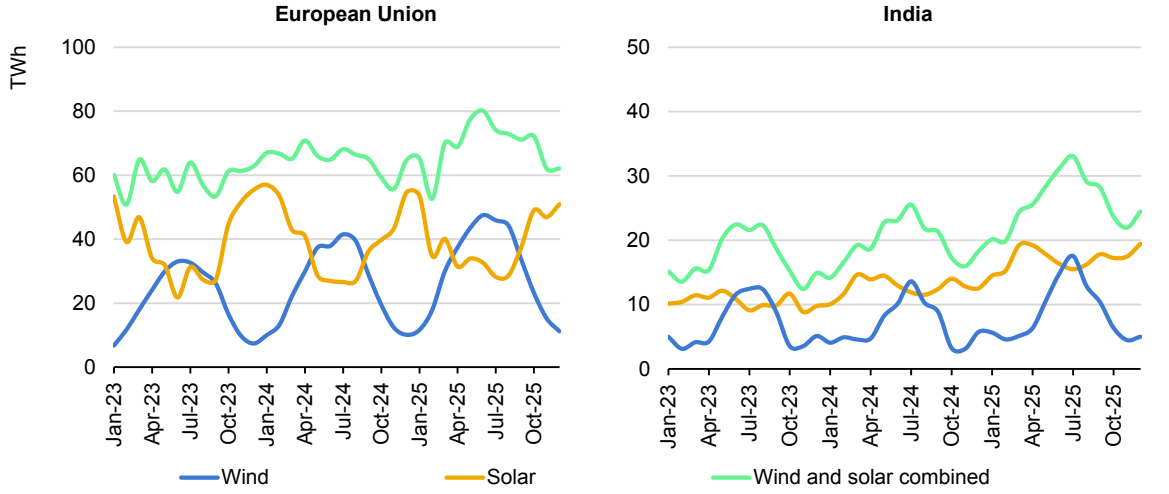
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Notes: LCOE = levelised cost of electricity. BESS = battery energy storage system. Green represents low-LCOE areas (~USD 30-75/MWh), yellow the middle cost range (~USD 75/MWh) and red the high range (~USD 75-120/MWh or more). All monetary calculations are in real terms, with a base year of 2025. "Demand fulfilment requirement" percentages refer to the hybrid project's annual average capacity factor, representing the share of demand requirement the system is expected to meet over the course of one year, month and daily peak hours (six hours per day: two hours in the morning and four in the evening).

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In India, the seasonal relationship between wind and solar is less complementary. Wind generation shows pronounced seasonal fluctuations, increasing sharply in the monsoon season and falling significantly during the rest of the year. By contrast, solar PV generation remains comparatively stable in all seasons, with much smaller variations in monthly output. Consequently, the combined generation profile is more strongly influenced by seasonal changes in wind production, resulting in greater variability than in the European Union.

Wind and solar PV electricity generation per month in the European Union and India, 2023-2025



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Sources: IEA analysis based on ENTSO-E and India National Power Portal.

These differences have important implications for hybrid renewable energy systems. In the European Union, wind and solar complementarity allows hybrid projects to achieve higher annual and monthly coverage with less coupled storage, mainly by shifting intraday demand. In India, achieving similar levels of seasonal supply stability would require different system configuration, with solar PV taking on a greater role and larger storage volumes needed to compensate for extended periods of lower wind generation outside of the monsoon season. Thus, optimal hybrid system design and storage needs are likely to vary significantly between the two regions.

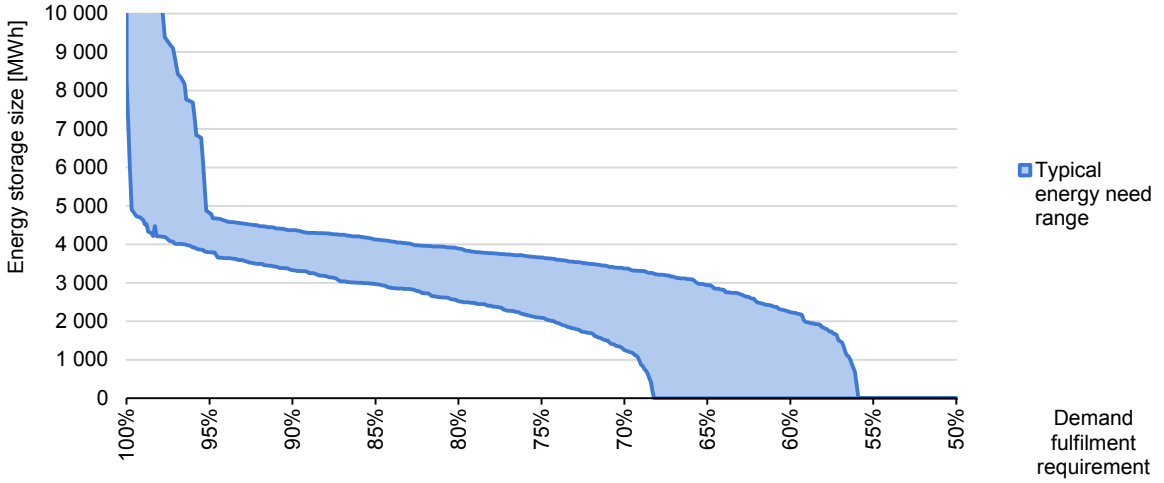
In both the main and accelerated cases, the lowest generation costs are concentrated in inland Australia, China, parts of North Africa, the United States, southern Africa and southern South America. Higher-cost regions include Central America, the Amazon basin, central Africa, the Zagros and Himalayan mountain ranges, much of Southeast Asia and Siberia, reflecting lower solar irradiation, weaker wind resources or more challenging terrain. The analysis excludes offshore wind, which could provide complementary energy in some regions.

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Battery storage can significantly improve the supply reliability of variable renewables by reducing weather dependence

Battery storage complements solar PV and wind generation by smoothing short-term variability and shifting output across hours or days. Storage requirements are determined to ensure sufficient charging during periods of renewable generation, to maintain electricity supply during subsequent periods of lower output. Solar PV provides a relatively predictable daily generation profile, enabling consistent day-to-day battery charging, although cloud cover and weather variability can affect output. Wind generation can further improve system performance by providing generation during both daytime and night-time hours and, in many regions, during seasons when solar output is lower.

Energy storage sizing example for 600 MW of solar PV and 600 MW of onshore wind to cover 300 MW of firm baseload at given annual demand fulfilment requirements, 2025



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Notes: Calculation is for a hybrid system combining 600 MW of solar PV and 600 MW of onshore wind capacity, comparing multiple selected regions in India. “Demand fulfilment requirement” refers to the minimum annual share of the specified demand profile that must be served by the hybrid system. “Energy storage size” refers to the usable battery storage energy capacity (MWh) required to shift surplus generation to unmet-demand periods to fulfil the given demand requirement ratio.

Analysis for India indicates that a twofold overbuild of solar PV and onshore wind capacity can provide annual baseload supply equivalent to around 55% of annual demand in favourable locations. Beyond this level, battery storage becomes unavoidable, as the supply requirement increases. Storage is particularly effective for managing short-term and intraday variability, enabling higher levels of demand fulfilment.

However, at very high reliability thresholds (above 90-95% in this example), seasonal variations in renewable output become the primary challenge. Addressing these infrequent but prolonged periods of low generation with battery storage alone would require substantial storage capacity that would be rarely

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utilised. As a result, achieving near-continuous supply is likely to necessitate a combination of long-duration storage technologies, other dispatchable renewable generation (e.g. geothermal), biogas and/or grid backup where available.

Higher demand fulfilment requirements for hybrid systems necessitate greater capacity overbuilding and surplus electricity generation. Hybrid systems combining solar PV, onshore wind and battery storage can yield a wide range of generation costs depending on reliability requirements and local conditions. Under a 70% annual demand fulfilment requirement (case 1), more than 50% of modelled locations achieve generation costs below USD 60/MWh, while almost 70% achieve costs below USD 75/MWh. Under stricter case-2 requirements (80% annual, 75% monthly and 90% peak demand fulfilment), costs for the same modelled locations can increase to USD 90/MWh and USD 110/MWh respectively.

Estimated projected LCOE costs vary significantly across regions. China records the lowest modelled costs, with most locations below USD 50/MWh in case 1 and below USD 60/MWh in case 2, reflecting favourable renewable resources alongside lower investment and financing costs. In contrast, ASEAN demonstrates the highest generation costs, with values reaching around USD 140/MWh in case 1 and USD 150/MWh in case 2 due to lower solar and wind output.

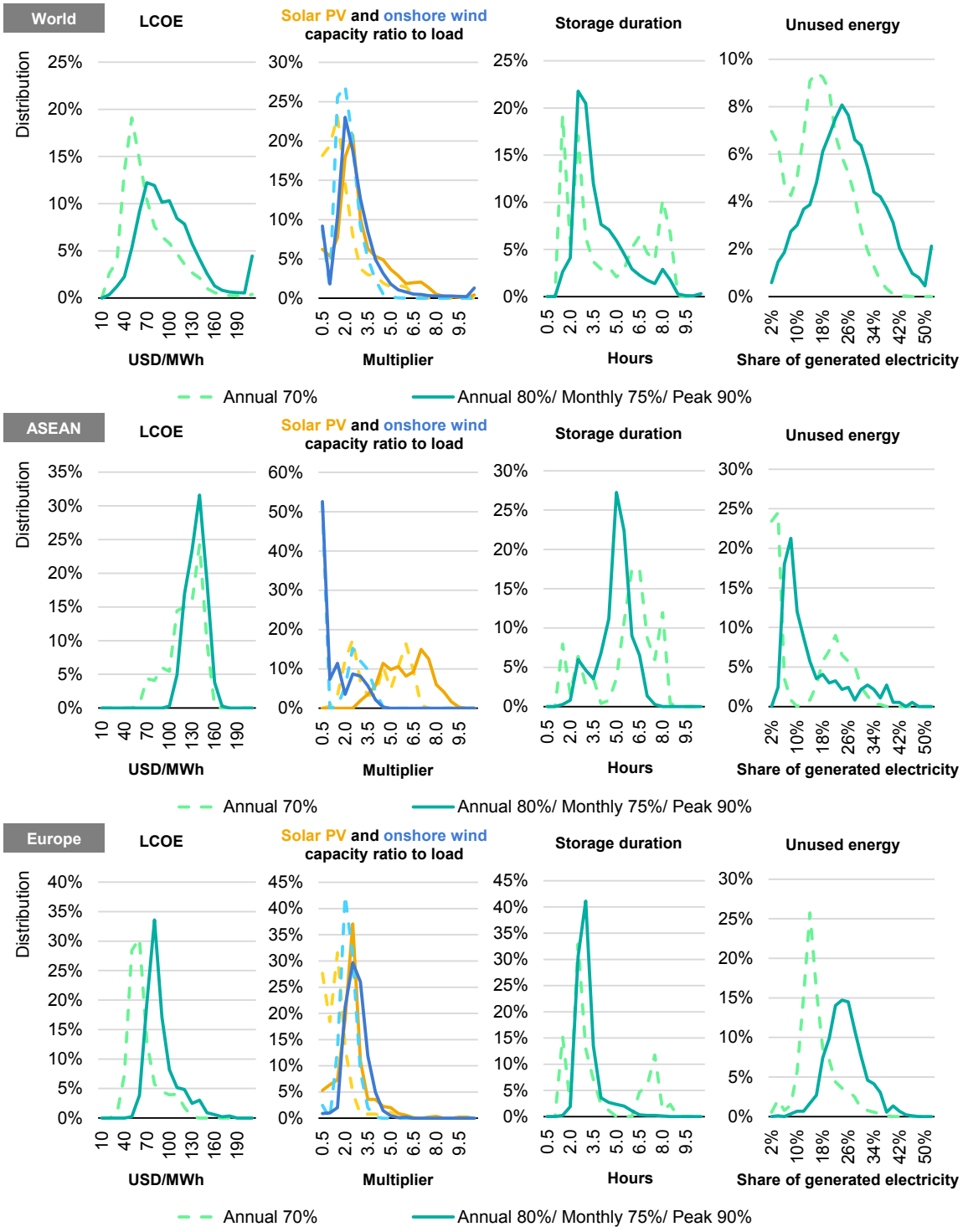
Increasing demand fulfilment requirements from case 1 to 2 generally raises levelised generation costs by approximately USD 30/MWh over the lifetime of the project for most modelled locations. This reflects the additional renewable generation and storage capacity required to achieve higher levels of supply reliability.

Moderate reliability (case 1) is achievable with limited storage, but stricter delivery requirements (case 2) sharply increase overbuild and storage needs. A solar PV-to-demand ratio of 1.5 (defined as installed solar PV capacity divided by baseload demand capacity requirements) combined with a wind-to-demand ratio of 2.5 and one to two hours of battery storage can meet case-1 requirements in around two-thirds of modelled locations.

Meeting the stricter case-2 requirements generally implies higher generation capacity-to-demand ratios, with capacity reaching 2.5 times demand for solar PV and 3 times demand for onshore wind, with four hours of battery storage. India and ASEAN are notable exceptions, requiring higher solar PV-to-demand ratios, reflecting lower solar output during the monsoon season. In ASEAN, weaker wind resources further increase generation requirements.

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Estimated main indicators for hybrid renewable projects (solar PV, onshore wind and BESS) supplying round-the-clock demand under two fulfilment cases, 2025



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Notes: BESS = battery energy storage system. LCOE = levelised cost of electricity. "Distribution" represents the share of land-based-integer latitude and longitude geographical pairs that are part of a given region for each parameter (i.e. LCOE, generation-to-load ratios, storage duration and unused energy). All monetary calculations are in real terms, with a base year of 2025.

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Higher demand-fulfilment requirements necessitate increasing levels of surplus generation. Across most modelled locations, more than 70% of hybrid system configurations result in excess generation of up to 20% under case 1, increasing to around 30% under case 2. This reflects the need to oversize renewable generation capacity to maintain supply during periods of lower solar and wind output.

The ability to utilise surplus electricity is likely to become an increasingly important determinant of hybrid system value. As battery storage cannot absorb all excess generation during periods of high renewable output, surplus electricity may need to be curtailed unless it can be redirected to flexible demand applications. Even when surplus electricity cannot be sold profitably on the electricity market, it retains value if redirected to applications that can utilise it flexibly. Potential uses include electric vehicle charging, water heating, industrial heating, power-to-molecule conversions, seasonal storage and other flexible-load applications that can increase capture rates and improve overall system utilisation.

India case study: What is the additional generation cost of matching hourly demand profiles compared with supplying baseload power?

To highlight the differences between meeting constant round-the-clock baseload demand and an hourly demand profile, we have developed a case study for India. As India's grid regions have distinct weather and electricity demand patterns that affect renewable generation profiles and costs, our analysis assesses each major grid region separately.

Annual solar irradiance distribution is broadly consistent across India, with solar PV output generally highest from January to May. Generation declines during the monsoon season due to increased cloud cover, but wind output shows much stronger seasonal and regional variations. Indeed, in the western and southern regions, it exceeds 50% of nominal generation capacity in many hours during monsoons, but it typically falls to 10-30% outside of this period. In the northern and eastern regions, wind capacity factors remain lower for most of the year, coupled with a less-pronounced monsoon-related increase.

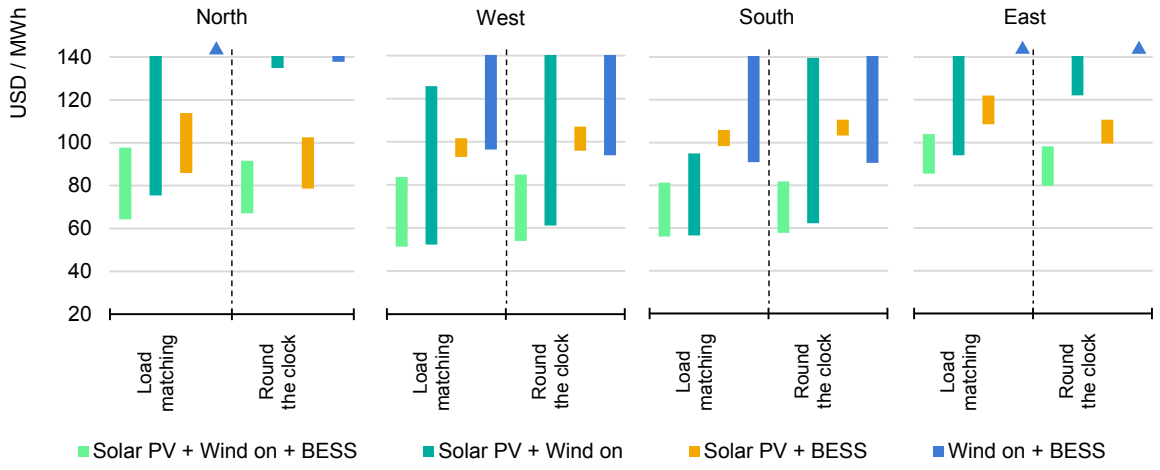
Overall, the lowest costs for firm renewable electricity generation can be achieved in the western and southern grid zones. These regions benefit from high and stable wind generation output all year round, coupled with stronger solar irradiation.

A hybrid project integrating all three assets – solar PV, wind and battery storage – ideally delivers the lowest-cost outcome, with an LCOE generally in the range of

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USD 60-100/MWh. Projects combining only two technologies can also approach the optimal cost level but can vary considerably. In the western and southern grid zones, pairing solar PV with wind – without storage – yields LCOEs at least USD 5/MWh higher than for optimised hybrid solutions. In the northern grid zones, and somewhat in the eastern ones, this difference increases to around USD 10/MWh.

Estimated LCOE to fulfil load matching and round-the-clock hybrid auction requirements, by various technology combinations and main grid zones in India, 2025



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Notes: Wind on = onshore wind. BESS = battery energy storage system. The results show a range of values covering multiple locations within the grid zone. "Load matching" means covering the grid zone's average hourly profile throughout the year, with a monthly demand-fulfilment ratio of 75%. "Round the clock" means fulfilling a baseload profile at annual coverage of 80%/monthly 75%/peak 90%. All monetary values are in real terms, using 2025 as the base year. The northeastern region was excluded because it represents less than 2% of India's national demand and has very unfavourable conditions for wind generation.
Sources: IEA analysis based on India Climate & Energy Dashboard; S. Pfenninger and I. Staffell (2016). Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data. Energy 114, 1251–1265, https://doi.org/10.1016/j.energy.2016.08.060 ; I. Staffell and S. Pfenninger (2016). Using bias-corrected reanalysis to simulate current and future wind power output. Energy 114, 1224–1239, https://doi.org/10.1016/j.energy.2016.08.068.

Load-matching to accommodate a demand profile can cost broadly the same as supplying constant round-the-clock demand when battery storage is available. Without storage, however, load matching is slightly less costly if the demand profile corresponds closely with renewable generation. Solar PV generation can align with cooling-driven daytime demand spikes, while generally stronger wind generation can cover morning and evening demand increases. By contrast, meeting constant round-the-clock demand without intraday shifting of electricity output requires greater overbuilding of generation capacity.

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Policy and procurement trends

Key points

- The current conflict in the Middle East has raised fossil fuel prices but has prompted only a few countries (e.g. Korea, Egypt) to raise ambitions; most revisions reflect routine plan updates, and China's new Five-Year Plan lowers global 2030 ambitions to 8 250 GW.
- In H1 2026, more than 100 GW of renewable capacity was awarded through competitive auctions globally, a rise of about 87% year-on-year with activity in China offsetting weaker procurement elsewhere, notably in Europe.
- Auctions remain the main driver of utility-scale renewable energy deployment, accounting for around 61% of global additions over 2026-2031. Global average prices in 2025 were USD 54/MWh for utility-scale solar PV and USD 53/MWh for onshore wind.
- Merchant projects and bilateral contracts, such as corporate PPAs, account for around 30% of utility-scale additions and are gaining ground, especially in Asia Pacific.

Global ambition to 2030

Emerging markets and developing economies excluding China raise their 2030 renewable ambitions

Following updated assessments of policies, plans and official estimates for almost 70 countries, **government ambitions add up to 8 250 GW of cumulative renewable power capacity globally in 2030**. This is over 1% (-106 GW) lower than in our previous update in December 2025.

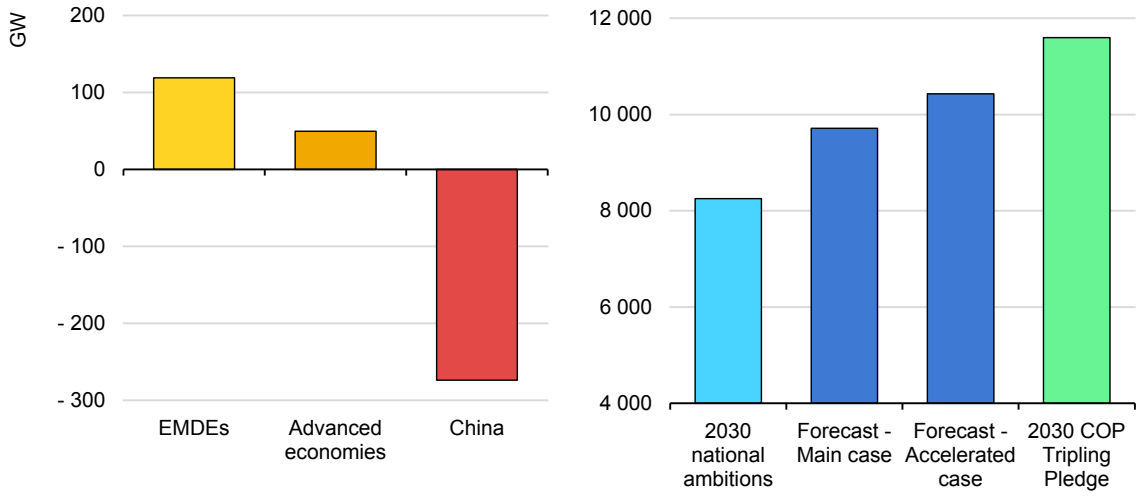
China's downward revision (-274 GW) more than offsets increases elsewhere. It follows the publication of China's 15th Five-Year Plan on Renewable Energy Development, which sets an indicative target of 3 500 GW of installed renewable capacity by 2030, lower than previous estimates.

Outside of China, ambitions have risen by around 4% (+168 GW) to 4 750 GW. **Emerging markets and developing economies (EMDEs) excluding China account for most of this increase**, adding almost 120 GW to their existing ambitions and reaching 1 925 GW. **Indonesia** alone accounts for 94 GW, after it launched its 100 GWp solar programme in August 2026, which explicitly aims to replace diesel-fired generation and cut diesel consumption. Higher fuel import costs following the Middle East conflict may have accelerated the adoption of such

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plans, which were already under discussion. Egypt, for instance, announced that it would bring forward its 45% renewables target from 2035 to 2028. Most other revisions reflect regular updates to planning documents, such as Brazil's latest Ten-Year Energy Expansion Plan (PDE 2035, +13 GW), while India's ambition was revised slightly downwards (-8 GW) in its latest Long-Term National Resource Adequacy Plan.

Revisions to 2030 renewable capacity ambitions by country group (left) and comparison of ambitions with the forecast and COP28 tripling pledge (right)



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Notes: EMDEs = emerging markets and developing economies. As the United States has no official national 2030 renewable capacity target, its ambition is set at its latest installed capacity; the US revision therefore reflects an update of this baseline to 2025 data rather than a new policy commitment.

Advanced economies raised their ambitions by almost 50 GW to 2 825 GW, although most of this (+43 GW) comes from updating the United States' baseline to 2025 installed capacity, which serves as its ambition in the absence of an official national target. The most significant policy-driven increase comes from **Korea** (+22 GW), which explicitly accelerated its plans in response to the Middle East conflict, raising its target under the Basic Plan for Renewable Energy from 78 GW to 100 GW and pledging to reach it before 2030. Elsewhere, changes mostly reflect routine updates to plans and projections. These raised ambitions in Australia (Emissions Projections 2025, +14 GW) and Colombia (Plan Indicativo de Expansión de Generación 2025-2039, +10 GW), but lowered them in Denmark (Climate Status and Outlook 2026, -10 GW), Chile (Long-Term Energy Planning, PELP 2023-2027, -9 GW) and France (Multiannual Energy Programme, PPE 2026-2035, -8 GW).

Renewable capacity is forecast to exceed current government ambitions for 2030 by around 18% in the main case, and to reach 90% of the COP28 tripling goal in the accelerated case. Renewable energy and energy security policies

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have been central to improving the cost competitiveness of renewables compared with fossil fuel-fired power generation. Together with falling technology costs, these policies are expanding demand beyond government-led procurement, with companies and households increasingly investing in renewable electricity to reduce exposure to volatile fuel prices, lower electricity bills and improve energy security.

Procurement trends to 2031

Competitive auctions become an even stronger catalyst of global renewable energy expansion, while market-driven procurement also gains ground

Competitive auctions have become the dominant renewable electricity procurement mechanism for utility-scale solar PV and onshore wind over the past decade. Unlike administratively set feed-in tariffs and premiums, for which the government sets offtake prices, competitive auctions allow developers to bid for the level of remuneration. The ability of competitive auctions to lower procurement costs and give governments greater control over deployment volumes has encouraged their widespread adoption.

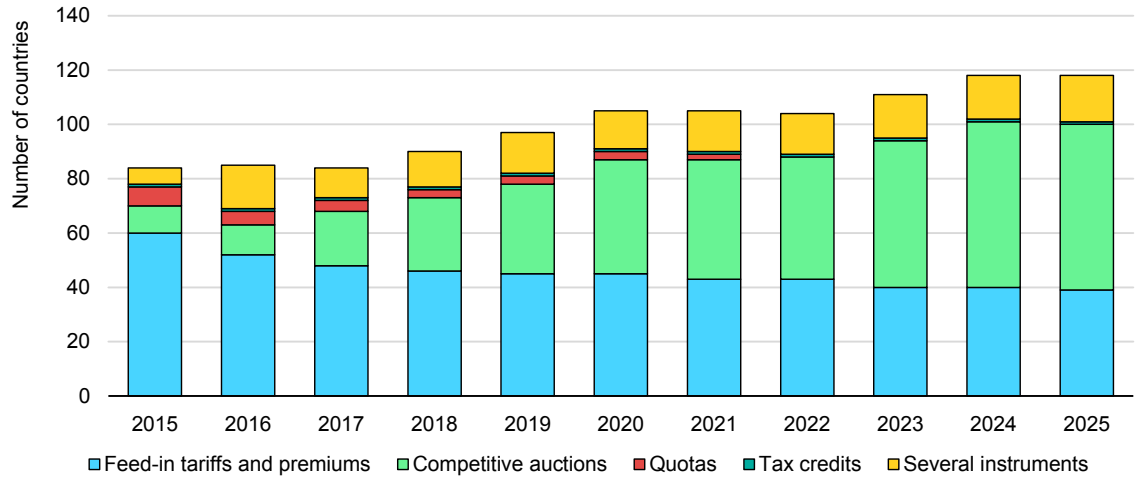
The number of countries using auctions increased from 4 in 2015 to 61 in 2025, overtaking those relying on feed-in tariffs or premiums in 2021. Over the same period, the number of countries using administratively set feed-in tariffs and premiums fell from 62 to 39 as governments increasingly shifted towards competitive procurement. Meanwhile, the number of countries using a combination of support instruments almost doubled as policy frameworks increasingly incorporated different mechanisms. For example, India, Korea and the Philippines combine quota obligations with auctions, while China used quotas, feed-in tariffs and auctions in 2025 as it transitioned towards competitive procurement.

The transition from feed-in tariffs to competitive auctions has fundamentally reshaped renewable power remuneration across Europe. While a large share of solar PV and wind capacity commissioned under earlier feed-in tariff schemes continues to generate electricity at relatively high remuneration levels, new projects are increasingly being contracted through auctions at significantly lower prices. Since the introduction of auctions, auction prices in selected countries have averaged around USD 75/MWh for utility-scale solar PV and USD 90/MWh for onshore wind, steadily reducing average fleet remuneration as low-cost capacity enters the system, with prices for awards in 2025 dropping to around USD 57/MWh for solar PV and USD 85/MWh for onshore wind.

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The impact has been particularly pronounced for solar PV, reflecting the large gap between historical support and recent auction outcomes. As a result, average solar PV fleet remuneration has fallen to around USD 78/MWh in Türkiye, while remaining closer to USD 100/MWh in markets such as Germany and France where a larger share of generation still benefits from legacy support schemes. Competitive procurement has therefore not only driven rapid renewable energy deployment but also significantly reduced the overall cost of renewable electricity over time.

National procurement policies for utility-scale solar PV and onshore wind by procurement type, 2015-2025



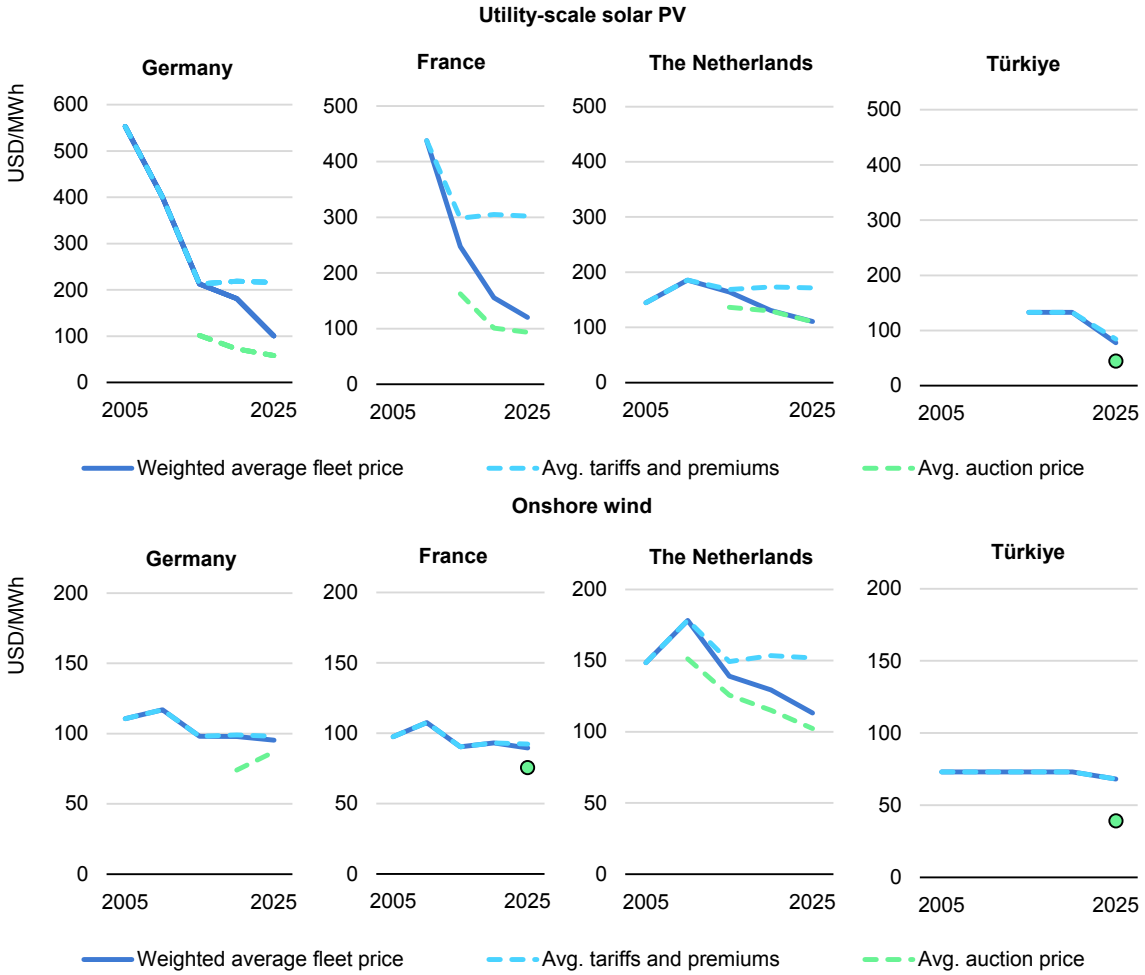
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Notes: The analysis covers national support frameworks for utility-scale solar PV and onshore wind. Countries are counted as using auctions from the year of their first auction, provided the enabling framework remains in place even if an auction is not held every year. Categories are mutually exclusive: countries using more than one instrument are counted only under "several instruments", which includes any combination of auctions, feed-in tariffs or premiums, quota obligations and tax credits.

In our forecast, competitive auctions account for more than 2 000 GW, or around 61%, of global utility-scale renewable capacity additions over 2026-2031, remaining the dominant procurement mechanism for utility-scale renewables. Merchant projects and bilateral contracts, including corporate PPAs and unsolicited contracts with utilities, account for almost 1 000 GW (around 30%) of additions, while the use of feed-in tariffs and premiums continues to decline, although they remain important for selected technologies such as CSP, pumped-storage hydropower and bioenergy.

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Weighted average remuneration for utility-scale solar PV and onshore wind fleets in selected European countries, 2005-2025



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Notes: Remuneration reflects feed-in tariffs or feed-in premiums set administratively and through competitive auctions. These levels may include explicit support when market or reference prices fall below guaranteed remuneration, as well as implicit support or cost reductions, such as publicly funded grid connections, land allocation or other enabling infrastructure. They should not be interpreted as levelised costs of electricity (LCOEs). Comparisons across markets should be made with caution because contract duration, auction design, revenue-stabilisation mechanisms and project and system cost allocations differ. Dots are used instead of lines when auction-supported projects first entered the fleet only in 2025, with no such projects commissioned in earlier years; the corresponding auctions were held before 2025.

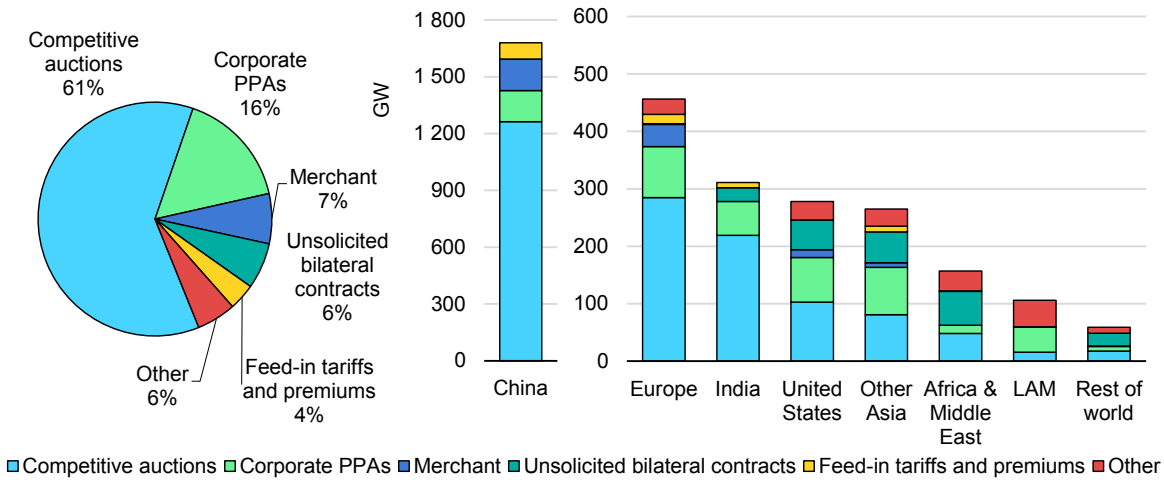
Renewable capacity expansion deriving from competitive auctions and, to a lesser degree, merchant projects and bilateral contracts, has increased since *Renewables 2025,* more than offsetting the fall in deployment through other procurement mechanisms. The resulting shift towards auctions is concentrated in the United States, Europe and India, where governments and state-owned utilities are increasingly using competitive procurement to achieve renewable deployment targets and provide long-term revenue certainty.

At the technology level, this shift is most pronounced for onshore wind: we are therefore revising auction-backed additions up by almost 100 GW from last year's

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forecast, more than offsetting reductions under other procurement mechanisms and raising the technology's overall outlook by over 73 GW.

Gross utility-scale renewable capacity additions by procurement type, 2026-2031



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Notes: LAM = Latin America. PPA = power purchase agreement. "Other" refers to other procurement mechanisms such as state-owned utility projects, green certificates and mechanisms not specified elsewhere. In the United States, utilities hold competitive auctions to meet state renewable portfolio standards.

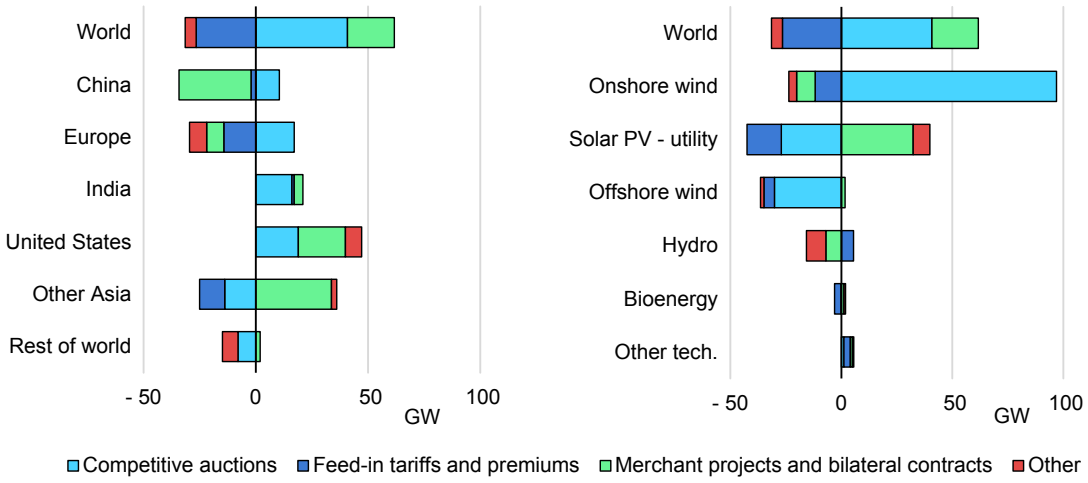
Europe accounts for over one-quarter of the global increases in auction-based procurement relative to last year's forecast, consisting largely of utility-scale solar PV. This reflects higher auction volumes and the gradual impact of permitting reforms that are expanding the pool of auction-ready projects. For instance, Germany's draft EEG 2027 proposes higher annual solar PV auction volumes to support the 2030 target, while recent permitting reforms have contributed to stronger participation in onshore wind auctions.

China remains by far the largest auction market, with around 1 260 GW, or over 60% of global auction-backed gross additions in 2026-2031. The share of auctions in China's utility-scale gross additions rises by 2 percentage points compared with *Renewables 2025*, with auction-backed onshore wind development surging in our forecast as provincial governments increasingly aim to rebalance deployment in favour of wind, following the country's rapid solar PV expansion and growing integration challenges. However, weaker project economics, particularly for merchant solar PV systems facing lower capture prices and higher curtailment, continue to hinder market-based deployment.

In India, a considerable pipeline of previously awarded projects supports auction-backed deployment, while procurement is increasingly shifting towards hybrid and firm-capacity products to address growing system-integration needs. The contribution of merchant projects and bilateral contracts is also higher compared with last year's forecast, owing partly to increasing corporate PPA activity.

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Change in gross utility-scale renewable additions since *Renewables 2025* by procurement type, region (left) and technology (right), 2026-2030



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Notes: "Merchant projects and bilateral contracts" refers to projects that gain revenues from the wholesale spot market, corporate PPAs or unsolicited bilateral contracts with utilities. "Other" refers to other procurement mechanisms such as state-owned utility projects, green certificates and mechanisms not specified elsewhere. In the United States, utilities hold competitive auctions to meet state renewable portfolio standards.

Outside of these major markets, market-based procurement is gaining importance, especially in Asia Pacific. Several ASEAN countries are expanding direct procurement options for corporate consumers, widening the role of bilateral contracting outside of traditional utility procurement models. Similar trends are emerging in Japan as support for new utility-scale solar PV projects gradually shifts towards market-based remuneration.

Competitive-auction trends

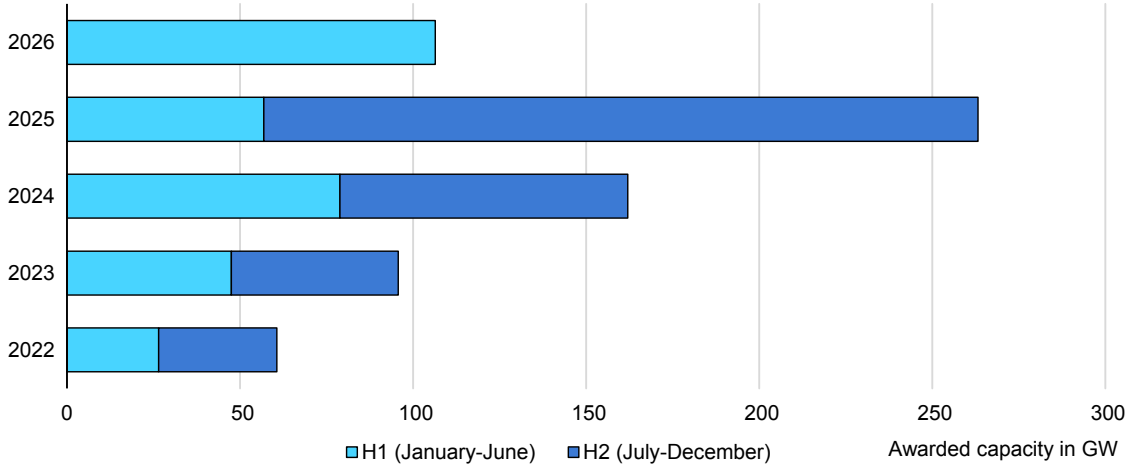
China's return to competitive auctions offsets weaker procurement elsewhere

In the first half of 2026, more than 100 GW of renewable capacity was awarded through competitive auctions globally, an 87% year-on-year rise. This is the highest first-half volume on record, surpassing the previous record set in 2024.

China led this increase after shifting renewable support from administratively set tariffs to competitive auctions in 2025. Since then, Chinese auctions have awarded almost 200 GW of renewable capacity, more than offsetting weaker procurement elsewhere. Excluding China, awarded capacity fell by almost 20% in 2025, and in the first half of 2026 it was around two-thirds the level recorded a year earlier.

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Global awarded capacity in competitive renewable energy auctions, 2022-2026



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Between 2022 and 2025, around 40% of annual auction awards were contracted in the first half of the year. However, this trend predates China's shift to competitive auctions and is therefore less indicative of 2026 volumes. With China's new auction framework substantially increasing procurement, global awarded capacity is expected to reach a new record in 2026.

China becomes the largest competitive-auction market as activity slows in Europe and India

China was the world's foremost competitive-auction market in the first half of 2026, awarding almost 70 GW and accounting for nearly two-thirds of global capacity awarded. However, volumes were just above half those recorded in the second half of 2025, indicating a moderation following the initial surge after the transition to competitive auctions.

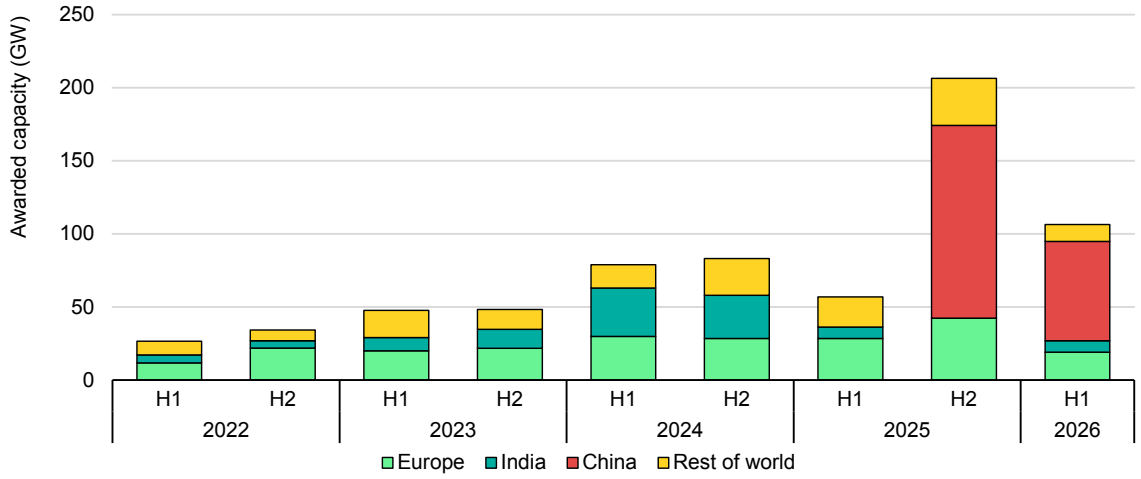
Europe awarded almost 20 GW in the first half of 2026, one-third less than in the same period in 2025. Ireland, Italy, the Netherlands, Poland and Türkiye had not held auctions by midyear, although together they accounted for around two-fifths of European awards in 2025. Several large rounds are scheduled for the second half of 2026, but Germany (at nearly 10 GW) and the United Kingdom (at more than 6 GW) already account for more than four-fifths of all capacity awarded so far in 2026.

India awarded around 8 GW, roughly the same volume recorded in the first half of 2025 but well below the peak of 33 GW in the first half of 2024. Financial constraints, administrative delays, changing demand expectations and a stronger

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preference for firm capacity have made distribution companies more selective in signing power sale agreements, prompting auctioning entities to reduce tender volumes.

Capacity awarded in competitive auctions by selected region/country, 2022-2026



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Awards in other regions fell to around 12 GW, roughly one-third the volume recorded in the previous six months. Activity was concentrated in Mexico, with 7.4 GW; Korea, with almost 2 GW of offshore wind; and Canada and Kazakhstan, with around 1 GW each. The decline stems largely from auction schedules rather than weaker procurement plans, with several large rounds expected in the second half of 2026, including almost 7 GW currently under tender in Australia.

Utility-scale solar PV and onshore wind dominate auction awards as offshore wind activity weakens

The technology mix of auction awards shifted further towards utility-scale solar PV and onshore wind in the first half of 2026. Between 2022 and 2025, these technologies accounted for around three-quarters of all awarded capacity, but their share increased further to 90% in 2026 as offshore wind procurement slowed.

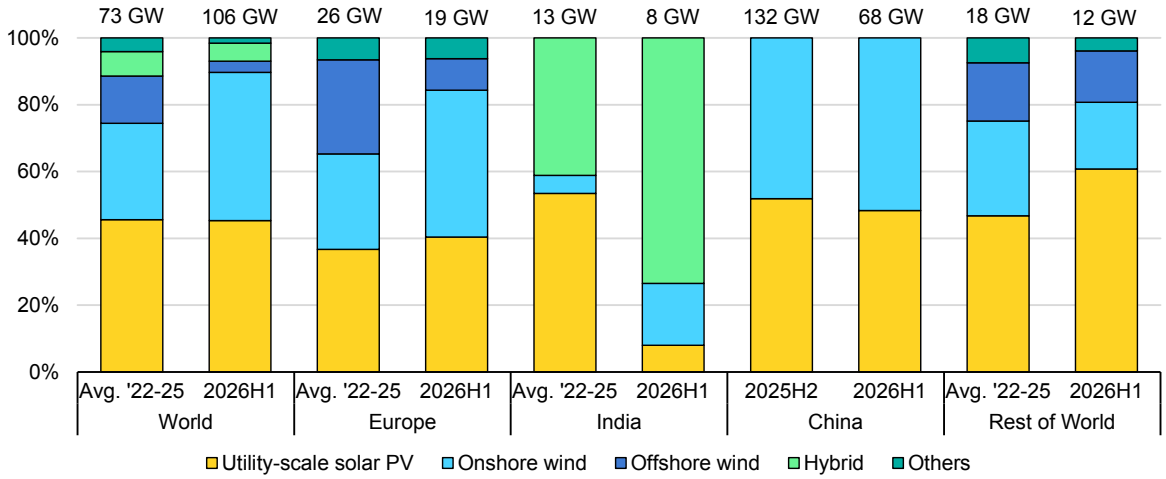
Utility-scale solar PV awards reached over 48 GW, roughly half of all capacity awarded. China contributed more than two-thirds of global volumes, while Mexico emerged as the second-largest solar PV auction market, awarding almost 7 GW in its first competitive procurement round since 2017. Europe awarded close to 8 GW, led by Germany and the United Kingdom. India awarded only 0.6 GW of standalone solar PV capacity, focusing more on firm-capacity auctions.

At over 47 GW, onshore wind made up around 44% of global awards in the first half of 2026, more than double the average of recent years. China accounted for

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almost three-quarters of global awarded capacity because of its new competitive auction framework, while Germany remained Europe's largest onshore wind auction market. The remaining capacity was awarded mainly in India, the United Kingdom and Canada.

Shares of capacity awarded in competitive auctions by technology, 2022-2026



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Note: Numbers above the columns represent average awarded capacity.

By contrast, offshore wind procurement slowed significantly. Only two countries concluded auctions globally in the first half of 2026, with Denmark and Korea awarding 1.8 GW each, while auctions in countries such as France, Chinese Taipei and the United Kingdom remained underway. Fewer scheduled tenders, project delays and ongoing adjustments to auction frameworks slowed activity.

Hybrid projects made up around 5% of awards, all procured in India. Their share of total awards as well as absolute awarded capacity were both broadly in line with previous years' averages. Other technologies made only marginal contributions, with limited awards for distributed solar PV, bioenergy, hydropower and tidal energy.

Shifts in procurement geography influence global auction price trends

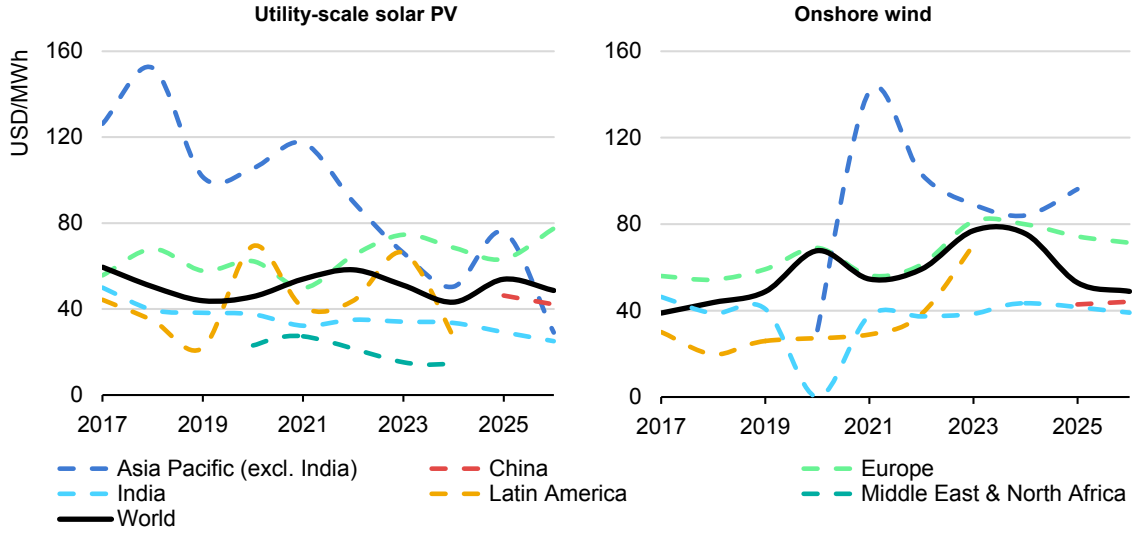
Changes in global weighted average auction prices continue to reflect where capacity is awarded rather than underlying price movements within individual markets.

The global weighted average price awarded for utility-scale solar PV increased from a record low of USD 43/MWh in 2024 to USD 54/MWh in 2025. Primarily a

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shift in procurement towards higher-priced markets – rather than broad-based price increases – spurred this rise. In 2024, large auction volumes in lower-priced markets such as India, Latin America and MENA pulled down the global average.

Weighted average utility-scale solar PV and onshore wind auction prices by selected region, 2017-2026



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The regional composition of awards changed markedly in 2025. Only a small amount of utility-scale solar PV capacity was awarded in Latin America and MENA, while India's share of Asia-Pacific awards fell significantly to less than 15%. At the same time, the Philippines accounted for almost 60% of Asia-Pacific awards at an average price of USD 82/MWh, while Europe represented one-fifth of global awarded capacity at around USD 63/MWh.

China's return to competitive auctions moderated upward price pressures. It accounted for almost 60% of global utility-scale solar PV awards in 2025 at an average price of USD 46/MWh. In the first half of 2026, its share increased further while average awarded prices declined to around USD 42/MWh, contributing to a fall in the global weighted average to USD 49/MWh despite higher prices in Europe.

Outside of China, Europe accounted for almost 16% of global awarded capacity in the first half of 2026, with average prices increasing 23% year-on-year to USD 78/MWh. Most European growth was in the United Kingdom, where utility-scale solar PV was awarded at around USD 89/MWh. By contrast, Germany, the only other European market with utility-scale solar PV auctions during the period, recorded only a marginal increase to USD 58/MWh. The share of the rest of Asia Pacific declined to less than 2%, limiting its influence on global price trends.

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Changes in procurement geography also had a strong influence on onshore wind auction prices. The global weighted average awarded price fell from over USD 75/MWh in 2023-2024 to USD 53/MWh in 2025 as large volumes of lower-priced capacity were awarded in China and auction prices declined in Europe. China accounted for almost two-thirds of global onshore wind awards at an average price of USD 43/MWh, while Europe represented over one-fifth of awarded capacity at USD 74/MWh.

China's growing role continued to shape global price trends in 2026. Although average auction prices increased slightly in China, its share of global awards rose to almost 75% while Europe's share declined to 18%. At the same time, auction activity in the rest of Asia Pacific remained limited and shifted towards lower-priced markets. As a result, the global weighted average onshore wind auction price declined a further 8% to USD 49/MWh in the first half of 2026.

Grid connection queues

Key points

- Global renewable energy and storage connection queues expanded rapidly in the last three years from around 3 500 GW to almost 4 400 GW in 2026 because grid-access bottlenecks are increasingly impeding faster development.
- Storage and hybrid projects now drive queue growth, with battery storage applications exceeding 1 500 GW (+900 GW in one year) and hybrid projects reaching 600 GW globally.
- Reforms are improving project-pipeline quality, with more than half of early-stage standalone solar PV and a quarter of wind projects having exited the queues, mainly in the United Kingdom (170 GW), the United States (160 GW) and India (95 GW).
- Overall grid connection queue volumes in India, Asia Pacific and Europe have doubled from previous years, while those in North America have increased by around 40%. Faster grid connections will be critical to unlock storage deployment and support system flexibility.

Global connection queues continue to grow, made up increasingly of storage and hybrid projects

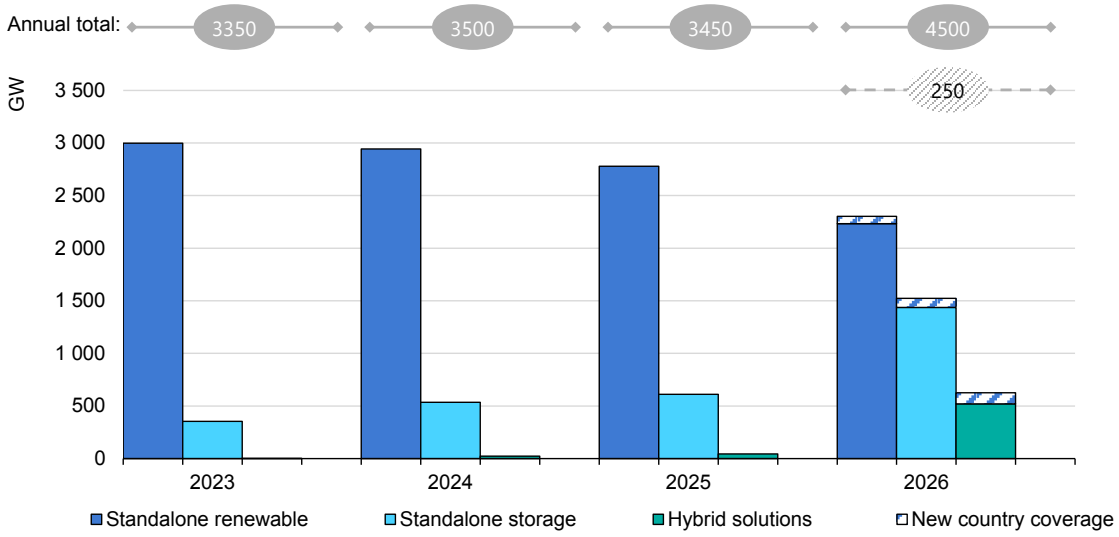
Global grid connection queues expanded globally in 2026, reflecting a shift in project applications from standalone renewable generation towards storage and hybrid systems. **While the volume of standalone renewable energy projects**

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in grid queues has declined, battery storage and hybrid projects have increased rapidly because power system managers are seeking greater flexibility to integrate rising shares of variable renewable generation. Improved system operator and regulator transparency have also expanded visibility over connection requests, particularly for storage and hybrid assets.

The total volume of projects in connection queues increased sharply from around 3 500 GW in recent years to almost 4 400 GW in 2026. Although around 250 GW of newly available data boosted this increase, most stems from genuine growth in project pipelines rather than from improved reporting alone.

Global grid connection queue development by technology, 2023-2026



IEA. CC BY 4.0.

Note: Solar PV values are a mixture of alternating current (AC) and direct current (DC), depending on the source.

Sources: Capacity totals are based on connection-queue data from countries.

US data is from CAISO; ERCOT; MISO; PJM; NYISO; ISO-NE and SPP interconnections; Appalachian Electric Cooperative; Arizona Public Service; Black Hills Colorado Electric; Bonneville Power District; Cheyenne Light, Fuel & Power; City of Los Angeles Department of Water and Power; Duke Carolinas; Duke Florida; Duke Progress; El Paso Electric; Florida Light and Power; Georgia Transmission Company; Imperial Irrigation District; Idaho Power; Jacksonville Electric Department; Louisville Gas and Electric Company and Kentucky Utilities Company; NV Energy; Portland General Electric; Public Service Company of New Mexico; Platte River Power Authority; Santee Cooper; Southern Electric Corporation of Mississippi; Southern Company; Salt River Project; Tucson Electric Power; Tri-State Generation and Transmission; Tennessee Valley Authority; and Western Power Administration. Japan data is from Hokkaido Electric Power Network, grid connection status of renewable energy projects; Tohoku Electric Power Network, grid connection status of renewable energy projects; TEPCO Power Grid, grid connection status of renewable energy projects; Chubu Electric Power Grid, grid connection status of renewable energy projects; Hokuriku Electric Power Transmission & Distribution, grid connection status of renewable energy projects; Kansai Transmission and Distribution, grid connection status of renewable energy projects; Chugoku Electric Power Transmission & Distribution, grid connection status of renewable energy projects; Shikoku Electric Power Transmission & Distribution, grid connection status of renewable energy projects; Kyushu Electric Power Transmission and Distribution, grid connection status of renewable energy projects; Okinawa Electric Power, grid connection status of renewable energy projects. India data is from CTU. Italy data is from TERNA. UK data is from Ofgem and NESO. Germany data is from Bundesnetzagentur; 50Hertz; Amprion; TransnetBW. Netherlands data is from Netbeheer Nederland. Finland data is from Fingrid. Poland data is from PSE. Hungary data is from MAVIR. Estonia data is from Elering. France data is from Service des données et études statistiques (SDES). Spain data is from Red Eléctrica de España. Australia data is from AEMO. New Zealand data is from Transpower. Mexico data is from CENACE. Brazil data is from ANEEL. Argentina data is from CAMMESA. Colombia data is from SIEL. Chile data is from CEN.

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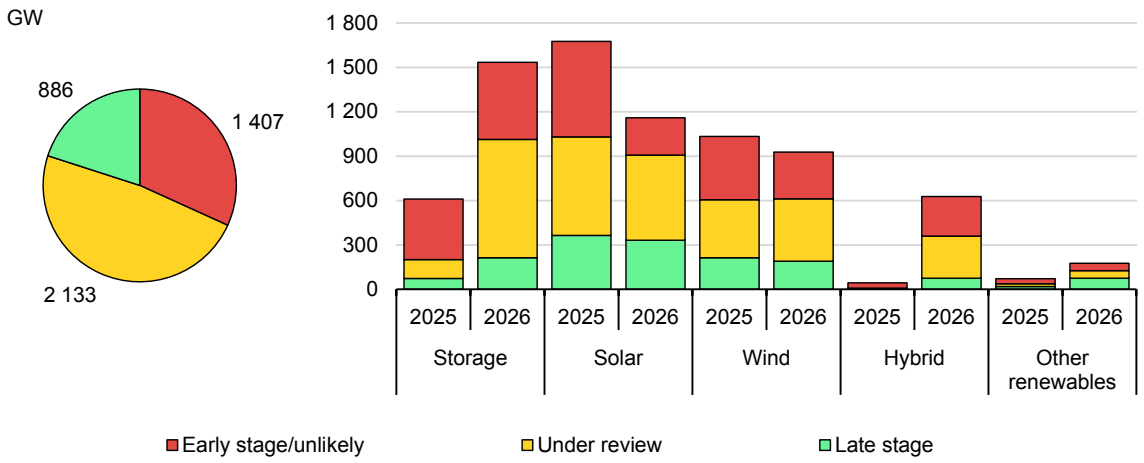
Hybrid projects are also emerging at scale with their volumes surpassing 600 GW in 2026, up from negligible levels in previous years. More than half combine solar PV and battery storage, while other hybrid configurations include wind-storage, solar-wind and multi-technology projects.

Standalone renewable projects in connection queues declined by around one-fifth in 2026, from around 3 000 GW to 2 300 GW, largely because early-stage and less mature projects exited queues when various countries introduced stricter connection management rules. **At the same time, battery storage applications expanded rapidly, increasing more than 900 GW in a single year to exceed 1 500 GW by mid-2026**. This shift reflects growing flexibility needs as power systems integrate higher shares of variable renewable generation.

Standalone solar PV and wind projects have exited queues because of stricter connection rules

Storage is now the largest project category in global connection queues, exceeding standalone solar PV as well as wind. More than half of queued storage capacity is already under review, a fivefold increase from last year, suggesting both greater project maturity and increasing prioritisation of storage applications by system operators. Meanwhile, the overall share of projects in advanced development stages has remained broadly stable, representing around 20% of the total, during the past three years.

Renewable energy capacity developments in connection queues by project stage, 2025-2026



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Note: Solar PV values are a mixture of alternating current (AC) and direct current (DC), depending on the source.
Source: Capacity totals are based on connection-queue data from countries.

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However, rapid growth in storage and hybrid applications – most of which are already under review – has enlarged the share of total queued capacity in advanced stages from around one-half to almost two-thirds. This indicates an overall improvement in queue quality despite continued growth in total connection requests.

The decline in standalone solar and wind projects was concentrated among early-stage and less mature applications. For queues of this category, solar PV capacity volume decreased by 60% and wind by 25% year-on-year, reflecting the introduction of reforms to prioritise more advanced and viable projects. Key queue management reforms include shifting from a "first-come, first-served" to a readiness-based approach (most notably by imposing stricter eligibility criteria and mandatory progress through project maturity milestones in a timely manner) and implementing financial guarantees to ensure project pipeline quality and greater transparency on grid capacity availability.

In parallel, several system operators are increasingly aligning queue management with long-term network planning to improve connection efficiency and system development. Conventional hydropower (including pumped storage) accounts for almost 90% of the other renewable capacity in queues, while bioenergy, geothermal and solar thermal applications make up the remaining 10%.

Connection reforms have visible effects in major markets such as the United Kingdom, the United States and India

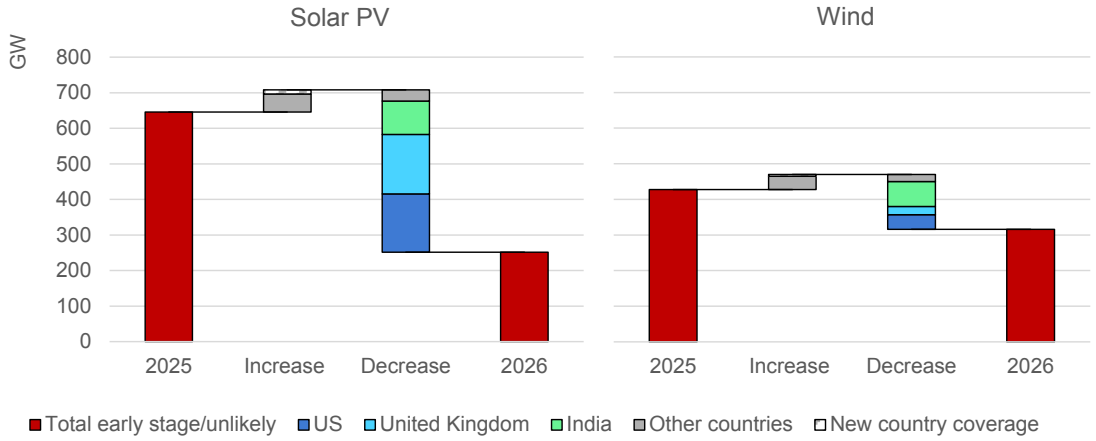
Thanks to stricter project screening, the United Kingdom, the United States and India account for almost half of the reduction in global connection queue volumes. In the United Kingdom, the TMO4+ reform has replaced first-come, first-served processing with a gate framework that prioritises projects based on strategic alignment and readiness. As a result, early-stage solar PV projects declined by almost 170 GW, with those lacking Gate 1 or Gate 2 approval falling by more than 90%.

In the United States, FERC Order No. 2023 introduced cluster-based interconnection studies, tighter readiness requirements and heavier withdrawal penalties, removing around 160 GW of non-viable projects while prioritising those having secured key development milestones. India has implemented similar reforms through amendments to its General Network Access framework**,** most notably the third amendment in 2025, a major revision of maturity and quality criteria, reducing early-stage projects by almost 95 GW.

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Other markets are pursuing complementary reforms tailored to local conditions. In Brazil, for example, the National Policy for Access to the Transmission System (PNAST) is replacing continuous applications with structured access windows, supported by stricter technical criteria, improved transparency on network availability and competitive allocation when grid capacity is limited. Although still at an early stage, these reforms are expected to improve queue quality by discouraging speculative applications and accelerating the progression of more advanced projects towards connection.

Countries with significant reductions of early-stage/unlikely solar and wind projects



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Note: Solar PV values are a mixture of alternating current (AC) and direct current (DC), depending on the source.
Source: Capacity totals are based on connection-queue data from countries.

Queues in India, Asia Pacific, Europe and North America expanded significantly in 2026

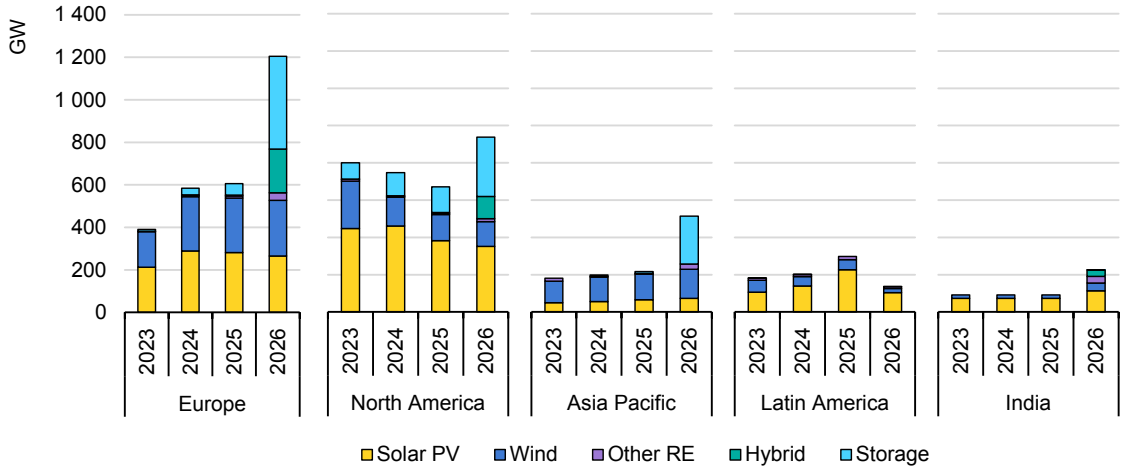
Storage queues are growing rapidly as grid access becomes the main deployment bottleneck. In 2026, battery storage increased the most in grid connection queues across Europe, North America and Asia Pacific, led by Italy, the United Kingdom, Germany, the United States, Japan and Australia. Together, these six countries account for more than 90% of global storage capacity currently awaiting grid connection.

Rapid enlargement of storage-project pipelines indicates that investment appetite is not the primary constraint on deployment. Instead, the rising concentration of storage projects in connection queues suggests that **grid access and connection timelines are increasingly the key bottleneck hindering project realisation.** As power systems integrate higher shares of variable renewables, enabling faster connection of storage assets will be critical to maintain deployment momentum and support system flexibility.

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Connection timelines are diverging across regions. While most capacity in queues is still expected to connect before 2030, Europe stands out with a growing share of projects assigned connection dates beyond 2030. As grid constraints intensify, several markets are introducing more flexible alternative arrangements, including shared grid access, cable pooling and non-firm connection agreements. These measures can accelerate storage deployment, improve network utilisation and alleviate congestion, reflecting the increasingly important role of storage as a source of both demand and supply in power systems.

Renewable energy capacity developments in connection queues by project technology



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Notes: RE = renewable energy. Solar PV values are a mixture of alternating current (AC) and direct current (DC), depending on the source.
Source: Capacity totals are based on connection-queue data from countries.

Performance-based and more harmonised tenders could accelerate grid expansion by reducing complexity. Specifying the required performance of grid assets, rather than prescribing detailed technical designs, could enable more efficient use of constrained engineering and manufacturing capacity. Spain's streamlined regulatory framework for repowering existing renewable assets provides one example. At the EU level, the European Grids Package complements national reforms by promoting readiness-based allocation, transparent project-maturity criteria, enforceable development milestones, and regular queue monitoring and clean-up.

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Renewable manufacturing supply chains

Key points

- More than 90% of Chinese solar PV manufacturers continue to report losses, with over 70 companies filing for bankruptcy or liquidation since 2024 as government policies accelerate industry consolidation.
- Despite consolidation and manufacturing growth in other regions, solar PV supply chains are still highly concentrated in China and are expected to remain so through 2031, particularly for polysilicon and wafer production.
- Selected solar PV manufacturers outside of China remain profitable despite global overcapacity owing to technological differentiation, policy-backed demand and trade measures limiting Chinese imports.
- Western wind turbine manufacturers continue to face margin pressures despite signs of financial recovery as Chinese original equipment manufacturers (OEMs) expand their presence overseas, intensifying competition across emerging markets.
- Supply chains for onshore wind remain more geographically diverse than for solar PV thanks to strong Western manufacturers, but also due to transport and logistical constraints. However, China is still in the lead, followed by Europe and India.
- Offshore-wind supply chains remain under pressure from weak demand visibility, project delays and grid connection bottlenecks, limiting investment even though major markets have sufficient manufacturing capacity.

While over 90% of China's solar PV supply chain is reporting losses, some key international manufacturers are staying profitable

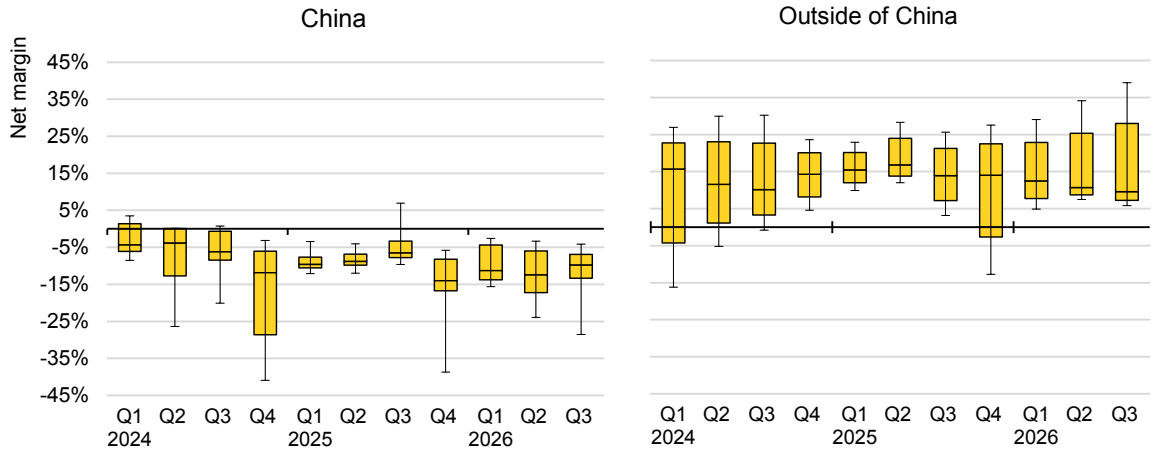
Solar PV component prices rose in 2026, with global average wholesale spot prices for crystalline silicon cells and modules rising 10-30% from 2025. Despite this increase, global average wholesale module prices remained at only around USD 0.12/W, still less than half the pre-2023 levels. Upstream segments continue to face pressure, with polysilicon and wafer prices declining up to 10% since 2025.

More than 90% of major Chinese solar PV manufacturers continue to report net losses. Higher module prices have not been sufficient to restore profitability across the Chinese solar PV manufacturing sector. The cumulative net loss of major China-based integrated solar manufacturers and polysilicon producers

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increased from around USD 4.4 billion in 2024 to almost USD 5.5 billion in 2025, underscoring the persistency of oversupply impacts and intense price competition across the value chain.

Distribution of integrated solar PV manufacturing companies' net margins (Q1 2024-Q1 2026)



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Box plot explanation: lower whisker: 10th percentile of analysed companies/lower box boundary: 25th percentile (Q1)/box centre line: 50th percentile (median)/upper box boundary: 75th percentile (Q3)/upper whisker: 90th percentile.
Sources: IEA analysis based on annual reports, investment plans and publications to Q3 2026 from Bloomberg LP and S&P Global Capital IQ.

Net margins stayed negative through the first three quarters of 2026, but there are signs that losses are stabilising. In recent quarters, the middle 50% of analysed companies reported net margins between -5% and -15%, a narrower range than the 0% to -30% recorded in 2024. Improvements have been concentrated among companies increasingly diversifying into higher-margin business segments such as battery storage, energy storage system integration and downstream project development, outside of core solar manufacturing activities.

In contrast, major manufacturers outside of China have remained profitable despite persistent weakness across the global solar PV supply chain. For these manufacturers, median net margins have remained broadly stable at 10-15% since 2023. Technological differentiation, localisation strategies and access to protected markets underpin their profitability, while trade measures limit their exposure to China's highly competitive domestic market. First Solar continues to benefit from its thin-film technology, domestic US manufacturing base and limited dependence on the Chinese crystalline-silicon supply chain. Meanwhile, Hanwha Qcells and Waaree have strengthened their positions through localisation strategies in the United States and India while further integrating their supply chains to improve cost competitiveness.

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Can consistently low market prices and increasingly stringent policies rebalance China's solar PV manufacturing sector?

Low module prices continue to encourage solar PV deployment globally, but the manufacturing sector remains under significant financial pressure. For polysilicon, wafers, cells and modules, production capacity continues to exceed demand, limiting the industry's ability to restore margins despite some recovery in component prices during 2026. Higher input costs for materials such as silver and aluminium further squeezed profitability in 2025, while intense competition prevented manufacturers from fully passing these costs through to customers. As input costs eased later in the year, component prices came under renewed pressure, reinforcing challenging market conditions across the value chain.

China's supply-side policy response to overcapacity in the solar PV manufacturing sector has become progressively more stringent since 2024. The policy focus has **shifted from guidance and compliance-signalling towards mandatory efficiency standards and tax-policy adjustments**, with the aim of increasing pressure for industry consolidation. These measures are likely to slow low-quality capacity expansion and accelerate the exit of weaker firms, although the most stringent measures are only due to take effect between 2026 and 2028.

As a result, market pressure and policy intervention are pushing the solar PV industry into a deeper phase of consolidation in China, as prolonged overcapacity, weak profitability and tightening policy conditions place growing pressure on manufacturers with high debt, lower-efficiency production assets and inferior product quality. More than 45 solar PV manufacturing companies filed for bankruptcy or liquidation during 2024-25, with around 25 additional cases reported in 2026.

Leading manufacturers have also reduced their workforce (e.g. Longi, Jinko Solar, JA Solar, Trina Solar and Tongwei) and accelerated restructuring efforts, while acquisitions are increasingly allowing stronger companies to absorb strategically valuable assets. **Overall, the consolidation process is expected to favour manufacturers with stronger balance sheets, higher-quality capacity and more competitive technology portfolios, accelerating the exit or absorption of weaker producers.**

The impacts of consolidation are expected to vary significantly across the solar PV supply chain. **Upstream segments will have to adjust the most** because they currently account for the majority of excess manufacturing capacity in China. Under a scenario in which the current pace of bankruptcies continues and no major new investments are made, global polysilicon manufacturing capacity could shrink by up to 45% by 2031, bringing it much closer to expected installation

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requirements. If market conditions improve and investment activity resumes, the reduction would be more limited at around 15%.

China government policy measures to tackle solar PV supply glut challenge

Action	Measure	Objective	Stringency
2024 - guidelines: Revised MIIT PV manufacturing Normative Conditions	Introduction of higher module and cell efficiency, technology, R&D, IP, quality, environmental performance, energy/resource use, safety and capital discipline requirement guidelines	Discourage unnecessary capacity expansion, raise technical thresholds and steer sector towards higher-quality, more financially disciplined manufacturing	
2025 - compliance update: MIIT-compliant-enterprise list update	Announcement and dynamic update of the currently valid list of enterprises complying with PV manufacturing conditions	Signal public compliance to the market and authorities as due diligence for regulatory credibility	
2025 - campaign: Anti-involution campaign in the solar PV industry	Administrative push for high-level meetings with leading firms to end disorderly price competition and retire outdated capacity	Encourage consolidation, with implementation still dependent on industry players and local governments	
2026 - support cancellation: Cancellation of export VAT rebate for solar PV	Ending of VAT rebates for PV products from April 2026, and for batteries in January of 2027	End support to exert upwards pressure on export prices	
2026 - standards: Solar PV module and inverter efficiency limits	Issuance of mandatory, legally binding efficiency standards for solar PV and inverter components and products, to take effect in 2027	Force inefficient products and production lines to upgrade or exit	
2026 - consumption tax: Reintroduction for mature solar PV and batteries	Gradual reintroduction of consumption tax of 2% from April 2027, then 4% from April 2028 on conventional solar PV cells	Provide selective support for next-generation (e.g. perovskite, tandem or gallium) technologies	

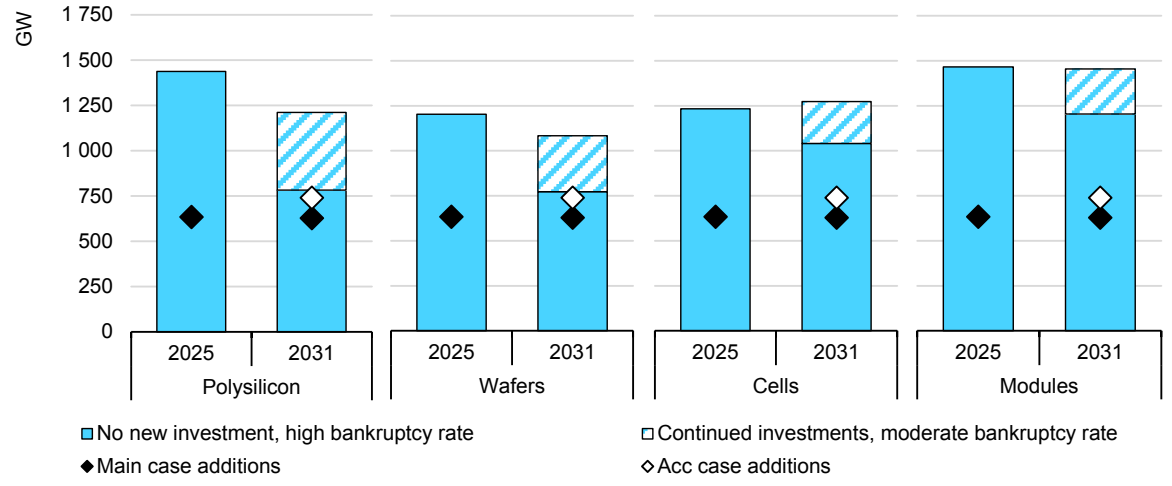
Stringency categorisation: = information or recommendation; = explicit administrative intervention; = mandatory measures.

Wafer manufacturing is also expected to undergo substantial consolidation, with capacity declining an estimated 10-35% by 2031 depending on market conditions. By contrast, cell and module manufacturing capacity is projected to fall only 5-15%, reflecting stronger downstream demand and continued investment in newer, higher-efficiency technologies. As a result, utilisation rates could improve,

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leading to a gradual recovery in prices to sustainable levels, as the prolonged oversupply has pushed prices below manufacturing costs for a large share of producers.

Manufacturing capacity along the global solar PV supply chain by component, 2025-2031



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Notes: Only the crystalline silicon supply chain is covered; thin-film modules are not included. "High bankruptcy" means 10% of capacity is affected annually, a continuation of recent trends, while "moderate" indicates 5% of capacity is affected during the forecast period. The "no new investment" case assumes that only a share of projects having reached final investment decision or already under construction are realised. Under "continued investments", a portion of announced and planned investments are also achieved.

Sources: IEA analysis based on data from PV InfoLink, BNEF, S&P and SPV.

New solar PV manufacturing hubs are slowly emerging downstream as consolidation pressures intensify in China

Polysilicon remains the most exposed segment of the solar PV supply chain. Production is electricity-intensive, which can encourage producers to maintain operating rates when power prices are low, even when product demand is weak, contributing to inventory accumulation. Some producers, including Daqo, have reportedly prioritised lower sales volumes over selling below cost, in line with industry self-regulation efforts encouraged by Chinese authorities.

At the same time, wafer manufacturers have reduced procurement due to weak downstream demand and already-elevated inventories. To address excess volumes, leading Chinese polysilicon producers established the Beijing Guanghe Qiancheng Technology company, a joint industry platform intended to support capacity optimisation, including through the potential acquisition and closure of lower-quality production capacity. However, the effectiveness of this mechanism

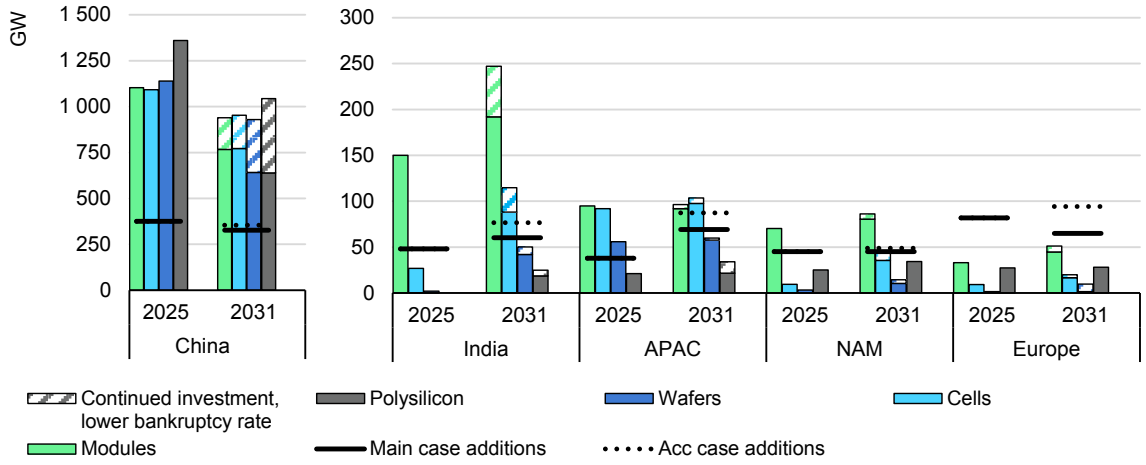
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remains uncertain, particularly given concerns that co-ordinated supply management or price-setting could be subject to regulatory scrutiny from competition authorities.

In parallel, the largest global polysilicon producer, Tongwei, proposed a national security reserve in China for polysilicon, further reducing finished product volumes. Polysilicon manufacturers outside of China have been experiencing similar market conditions, with Wacker reporting lower sales of lesser-quality solar PV-grade polysilicon (as sales of hyper-pure semiconductor-grade polysilicon increased).

Wafers are the last segment of the solar PV supply chain, where inventories can still be stored with relatively high flexibility because wafers are tied less to a specific downstream technology than cells or modules are. By contrast, cells and modules are produced using rapidly evolving technologies and the risk of earlier obsolescence is higher, as illustrated by the market shift from PERC to TOPCon technologies and other high-efficiency formats. Downstream products also require more storage space and stricter handling conditions. As a result, inventory accumulation is likely to remain concentrated in polysilicon and wafers, while turnover pressure is stronger for cells and modules.

Regional solar PV manufacturing capacity and installations, 2025-2031



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Notes: APAC = Asia Pacific. NAM = North America. Only the crystalline silicon supply chain is covered; thin-film modules are not included. “High bankruptcy” means 10% of Chinese capacity is affected annually, a continuation of recent trends, while “moderate” indicates 5% of capacity is affected during the forecast period. For capacity outside China, the range reflects uncertainty over the realisation of announced projects rather than bankruptcy assumptions.

Sources: IEA analysis based on data from PV InfoLink, BNEF, S&P and SPV.

Most emerging solar PV manufacturing capacity outside of China is dedicated to cells and modules, as these segments require lower upfront investment than upstream polysilicon and wafer production. Higher energy and

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labour costs in many markets outside China also weigh more heavily on the competitiveness of upstream production, further favouring investment in cells and modules. New entrants can also invest directly in higher-efficiency production technologies, such as TOPCon, back-contact or HJT cells, avoiding costs related to converting existing PERC production lines. Trade barriers and industrial policies are also increasingly influencing the location of new manufacturing capacity. However, in the current low-price environment, new manufacturers need clear competitive advantages in their target markets, such as technological differentiation, policy support, local-content advantages or strong domestic demand, as illustrated by First Solar, Hanwha Qcells and Waaree.

India has the most notable emerging manufacturing ecosystem, with several new wafer, cell and module manufacturing projects under development, driven by policies targeting imports, support from the Production Linked Incentive (PLI) scheme and rapid domestic demand growth. Waaree Energies is also moving further upstream with plans for polysilicon and wafer production, although upstream manufacturing remains more challenging because most equipment, technical expertise and polysilicon inputs are still closely linked to China. Moreover, access to competitively priced Chinese wafers, which historically faced fewer import barriers than cells and modules, limited incentives to develop domestic wafer production. India is therefore also extending domestic-content requirements further upstream under the Approved List of Models and Manufacturers (ALMM) framework, covering modules, cells, subsequently, wafers from 2028, to incentivise further localisation of the supply chain.

As margin pressure persists in core solar PV manufacturing, leading companies are increasingly looking towards adjacent growth markets, most notably battery storage. This shift would offer synergies and access to a faster-growing segment with potentially stronger margins, but it also risks transferring the solar industry's overcapacity dynamics into the battery supply chain if expansion again overtakes demand.

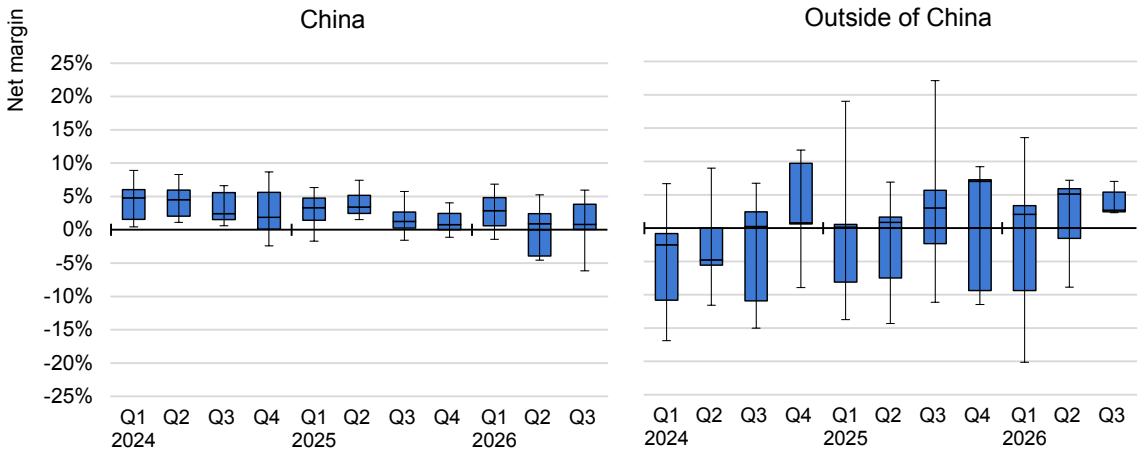
Several large PV manufacturers are already accelerating this transition: GCL Technology is aiming to enter the battery manufacturing supply chain by providing raw materials built on its existing polysilicon-based capabilities; JinkoSolar plans to expand its battery manufacturing capacity from around 5 GWh to 13-14 GWh by end-2026; Trina Solar has described storage as a second growth curve, with its storage business expanding rapidly; Canadian Solar has built a major utility-scale battery energy storage system (BESS) integration business through its e-STORAGE subsidiary; LONGi has entered the storage market with integrated solar-plus-storage solutions; and JA Solar has also announced a strategic move into energy storage.

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Strong domestic demand sustains profitability for Chinese wind turbine manufacturers while financial recovery remains uneven outside of China

Chinese wind manufacturers continue to face margin pressure, but the sector remains significantly more profitable than the solar PV industry. Strong domestic demand, with annual installations exceeding 110 GW in 2025, continues to support profitability, as the Chinese market accounts for more than 90% of sales for most domestic manufacturers. In emerging markets, lower manufacturing costs and increasingly larger turbine models are helping Chinese suppliers gain market shares, particularly in greenfield projects with strong wind resources. As a result, the middle 50% of analysed companies maintained positive net margins of 0-6% in recent years.

Distribution of net margins for integrated wind manufacturing companies, Q1 2024-Q1 2026



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Box plot explanation: lower whisker: 10th percentile of analysed companies / lower box boundary: 25th percentile (Q1) / box centre line: 50th percentile (median) / upper box boundary: 75th percentile (Q3) / upper whisker: 90th percentile.
Sources: IEA analysis based on annual reports, investment plans and publications to Q3 2026 from Bloomberg LP and S&P Global Capital IQ.

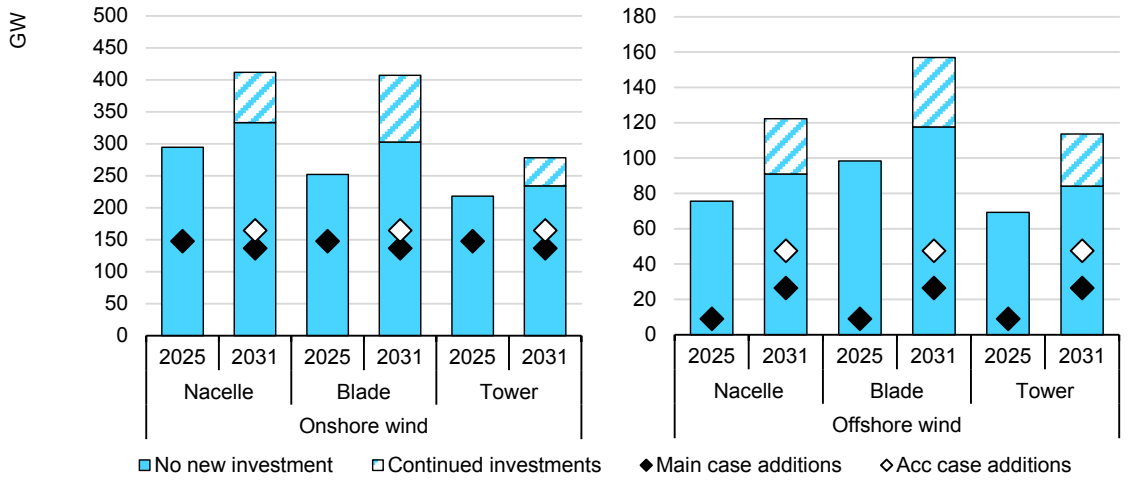
Western wind manufacturers are showing gradual signs of financial recovery, although profitability remains uneven across the industry. Overall, annual net losses among major manufacturers outside of China fell by half in 2025 compared with 2024, to around USD 0.9 billion. Established service businesses, global market presence and strong positions in offshore wind still support earnings. Nevertheless, higher manufacturing costs, supply-chain challenges and slower project execution are adversely affecting performance. Median net margins showed signs of gradual improvement in 2026, as most manufacturers reported decreasing losses and returned to positive net margins by the third quarter.

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Wind turbine prices outside of China remained broadly stable at just over USD 1 million/MW in 2025. Declining steel prices largely offset increases in copper and aluminium costs, keeping overall manufacturing expenses relatively contained. In contrast, Chinese-manufactured turbines continued to be offered at discounts of as much as 50% below the international price, underpinning their growing competitiveness in emerging markets. While contract structures complicate direct price comparisons, rising demand for copper and aluminium for grids and electrification, together with increasing trade restrictions, could raise cost pressures over the medium term.

Unlike for solar PV, wind turbine manufacturing can be more regional in nature because turbines are often tailored to market- and project-specific requirements, while the large size of blades, towers and other components increases transportation costs and logistical complexity. Manufacturing capacity could be located closer to deployment markets and supported by local assembly and service networks. Furthermore, wind manufacturing capacity is affected by turbine design: as turbine ratings increase, factories can deliver more megawatts of annual output even if the number of turbines produced remains broadly stable.

Manufacturing capacity along the global wind supply chain, by component, (2025-2031)



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Notes: The “no new investment” case assumes that only a share of projects having reached final investment decision or already under construction are realised. Under “continued investments”, a portion of announced and planned investments are also achieved. No bankruptcy is expected among the major players of the wind manufacturing industry during the forecast period. Acc. case = accelerated case.

Sources: IEA analysis based on data from S&P and BNEF.

Global manufacturing capacity for wind components is expected to increase 10-20% by 2031, partly reflecting a shift towards higher-output turbine models. If announced investments are realised, manufacturing capacity could expand by additional 20-40%, supported by local-content requirements and efforts to develop more regionalised supply chains. In both the main and accelerated cases, global

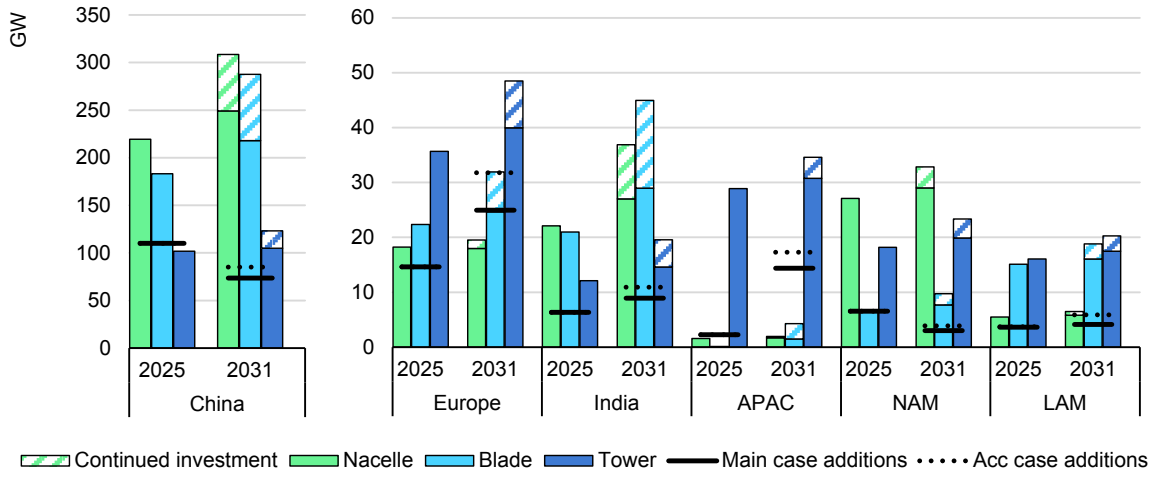
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manufacturing capacity is more than double expected installation requirements, although significant differences persist across regions and components, and between onshore and offshore wind supply chains.

Chinese onshore wind manufacturers are expanding internationally while Western original equipment manufacturers focus on core markets

China remains the dominant manufacturing hub for wind equipment, with sufficient blade, tower and nacelle capacity to meet projected deployment through 2031. While record installations in 2025 temporarily tightened the tower segment, manufacturing capacity still exceeds expected demand for all major components. Compared with solar PV, the market is characterised by fewer large manufacturers and lower fragmentation, although intense competition and low domestic prices continue to squeeze margins. As a result, leading Chinese OEMs are accelerating international expansion to capture more favourable pricing opportunities, supplying projects across Brazil, Saudi Arabia, India, Kazakhstan, Egypt and Southeast Asia while increasingly targeting opportunities in Europe.

Regional onshore wind manufacturing capacity and installations, 2025-2031



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Notes: APAC = Asia Pacific. NAM = North America. LAM = Latin America. Acc. case = accelerated case.
Sources: IEA analysis based on data from S&P and BNEF.

Outside of China, established manufacturers continue to benefit from strong service businesses, local manufacturing footprints and established customer relationships. Meanwhile, local-content requirements, industrial-policy support and trade restrictions in several markets are encouraging domestic manufacturing

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investment (for example in the European Union, United Kingdom, Türkiye or India), although demand visibility remains critical for sustaining further supply-chain expansion.

Most regions outside of China have sufficient manufacturing capacity across the main onshore wind component groups, supported by established production facilities and service networks. China remains the dominant supplier globally, while India has emerged as the largest manufacturing hub outside of China, with utility-scale and hybrid renewable auctions driving demand. India's manufacturing base is particularly strong in blade and nacelle assembly, although exports remain limited as manufacturers continue to prioritise domestic demand.

ASEAN remains the main exception to regional self-sufficiency. Wind power deployment in the region is expected to stay dependent on imported components, particularly nacelles and blades, reflecting limited domestic manufacturing capacity and less-developed supply chains. As a result, international suppliers will be able to strengthen their presence in the region. Chinese OEMs have already expanded rapidly across Southeast Asia, Latin America, the Middle East and Central Asia owing to their competitive pricing and growing experience in international project delivery.

Offshore wind manufacturing is expanding selectively as demand visibility remains the key investment driver

To expand offshore wind deployment and manufacturing, longer lead times are generally required than for onshore wind, reflecting higher complexity across the supply chain. Offshore projects call for specialised turbines, foundations, substations, subsea cables, installation vessels and port infrastructure, resulting in longer development and construction timelines. As a result, **offshore wind is more exposed to permitting delays, grid connection constraints, supply-chain bottlenecks and changes in financing conditions.** Manufacturing investment is therefore closely linked to demand visibility and long-term auction pipelines.

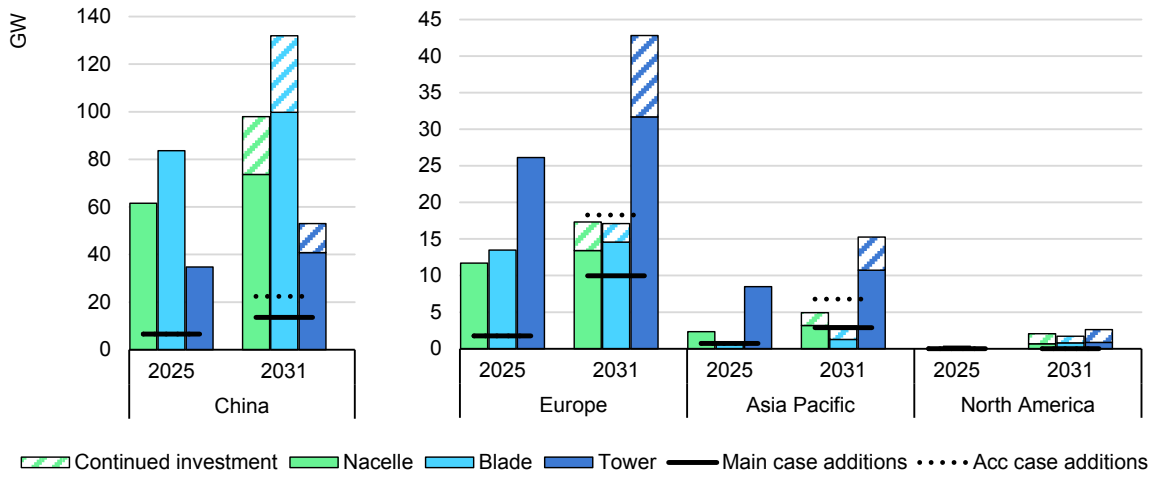
China is expected to remain the dominant offshore wind manufacturing hub in 2031, thanks to its closely integrated supply-chain ecosystems spanning manufacturing, testing and certification. As offshore development shifts towards larger projects, deeper waters and floating technologies, China continues to expand its technological capabilities, supported by a rapidly growing domestic market.

Current manufacturing capacity exceeds expected domestic demand by five to ten times depending on the component, placing greater pressure on suppliers to expand internationally and compete in export markets. China’s coastal manufacturing clusters and offshore installation capabilities strengthen its export

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potential, although the large size of offshore wind components means that proximity to deployment markets will continue to be an important advantage.

Regional offshore wind manufacturing capacity and installations, 2025-2031



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Sources: IEA analysis based on data from S&P and BNEF.

Europe remains the second-largest offshore wind manufacturing region, with established capabilities in Denmark, France, Germany, Spain, Portugal and Italy as well as new factories under construction in the United Kingdom and Poland. Manufacturing capacity for major components is broadly sufficient to meet near-term demand, reflecting slower deployment growth in recent years. Today's offshore deployments are increasingly more constrained by permitting or construction delays and grid availability than by manufacturing capacity shortfalls, although certain sub-component-level supply-chain risks remain.

While these uncertainties present immediate challenges for manufacturers, accelerated deployment in line with policy ambitions could require additional capacity over the long term. In both the main and accelerated cases, long-term visibility of auctions and planned projects is essential to sustain existing manufacturing capacities and enable timely investment across the wider offshore wind supply chain, including ports, vessels, grid equipment and skilled labour.

Smaller offshore wind markets are beginning to develop local supply chains, although capacity remains insufficient to achieve long-term deployment ambitions. In Asia, manufacturing capabilities are expanding in Korea and Chinese Taipei, while Viet Nam has established a sizeable tower manufacturing industry focused largely on exports. India's offshore wind supply chain remains in the early stages of development, and manufacturing is still geared primarily towards onshore wind. More broadly, the development of local offshore wind industries in emerging

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markets will depend on the availability of a predictable project pipeline supported by clear policy signals, port and grid infrastructure planning, and workforce development.

Behind-the-meter battery storage

Key points

- Behind-the-meter battery storage expands more than fivefold, exceeding 670 GWh by 2031, as falling battery costs improve the economics of self-consumption and flexibility services.
- Today, residential batteries make up 65% of total behind-the-meter storage capacity, but commercial battery deployment accelerates rapidly, accounting for almost half of global additions over 2026-2031.
- China emerges as the dominant commercial battery storage market at around 60% of global commercial additions and over 150 GWh of new capacity through 2031.
- Battery storage is increasingly deployed alongside distributed solar PV, with annual residential battery additions rising from the equivalent of 13% of rooftop solar PV additions in 2025 to over 35% by 2031.

Behind-the-meter battery storage is increasingly being deployed with distributed solar PV systems. While utility-scale batteries primarily support grid services and renewable energy integration, behind-the-meter systems enable households and businesses to increase self-consumption, lower electricity costs and reduce peak demand. Residential battery deployment remains closely linked to rooftop solar PV, though standalone storage is expanding in some regions; in the commercial segment, both solar-plus-storage and standalone battery applications are gaining traction. If well managed, behind-the-meter storage can be a key source of power system flexibility.

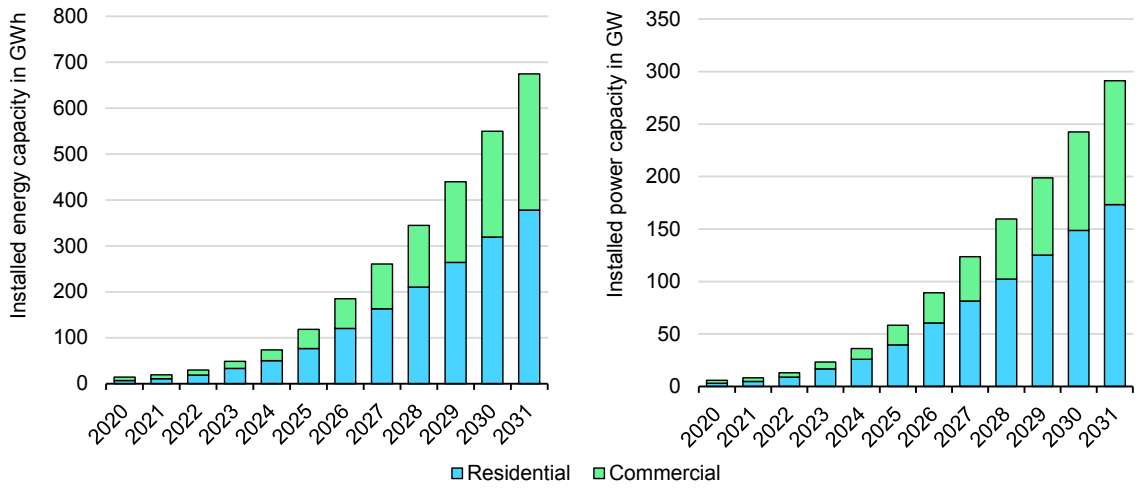
Installed behind-the-meter storage is forecast to exceed 670 GWh of energy capacity by the end of the forecast period, while power capacity reaches roughly 290 GW. Falling battery costs, better economics for self-consumption and growing recognition of the value of flexibility are expected to drive both residential and commercial deployment, enabling higher levels of distributed solar PV integration and strengthening system resilience.

Over 550 GWh of energy storage capacity and around 230 GW of power capacity are added during 2026-2031. Energy storage capacity additions are

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over five times those of the preceding six years, while power storage capacity additions more than quadruple. Growth is increasingly balanced across customer segments, with commercial storage accounting for almost half of new deployment compared with only one-third during 2020-2025. Rising electricity costs, improved storage economics and expanding flexibility markets are encouraging stronger uptake among commercial and industrial consumers.

Global installed behind-the-meter energy storage capacity (left) and power storage capacity (right) by segment, 2020-2031



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Notes: Residential systems are installations with less than 30 kW of power storage capacity and below 30 kWh of energy storage. Commercial systems have power storage capacity of 30 kW to 1 MW, or energy storage of 30 kWh to 1 MWh.

Sources: IEA analysis based on data from BloombergNEF (2026), Energy Storage Market Outlook 1H 2026; RWTH Aachen University (2026), Battery Charts, using data from Bundesnetzagentur (2026), Marktstammdatenregister (for Germany); Terna (2026), Data Portal: Storage (for Italy); Australian Government Clean Energy Regulator (2026), Small-Scale Installation Postcode Data (for Australia).

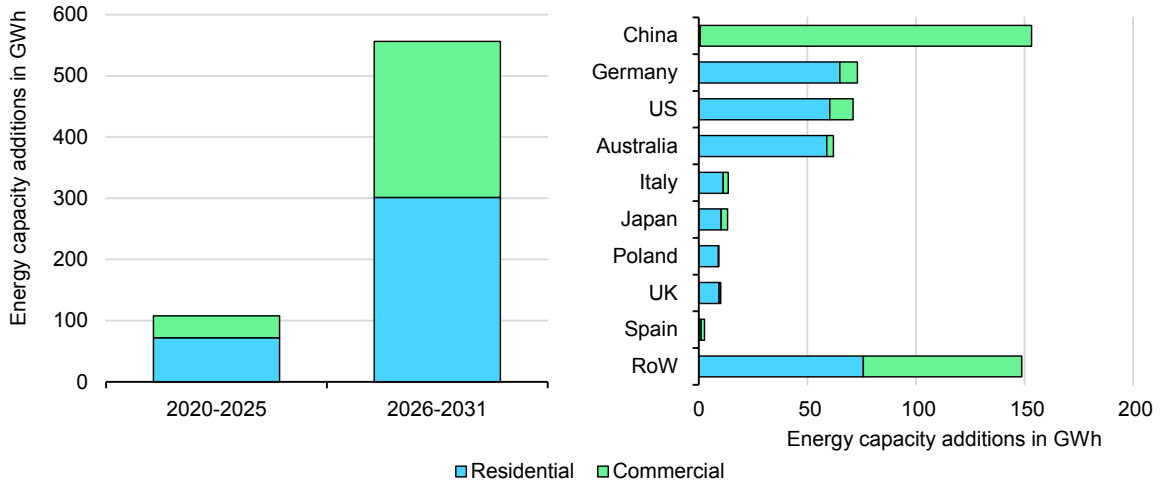
Commercial deployment remains highly concentrated in China, which accounts for 60% of forecast additions in the segment, or over 150 GWh. This makes China the largest commercial storage market in terms of both additions and installed capacity in 2031. Growth results from peak-shaving and load-shifting opportunities under industrial time-of-use tariffs, as well as emerging virtual power plant business models that enable participation in electricity trading and demand-response markets. The United States and Germany also contribute significant commercial storage growth.

Residential deployment is more geographically diversified. Germany, the United States and Australia together account for over 60% of additions, reflecting the continued expansion of rooftop solar PV-plus-storage systems. Germany remains the largest residential storage market, attaining almost 85 GWh of installed energy capacity by 2031.

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Direct financial incentives in several major markets support behind-the-meter storage deployment. Australia's Cheaper Home Batteries Program provides a discount of around 30% on eligible batteries and supported 4.6 GWh of deployment in its first six months, while Japan's Demand Response Home Battery Programme assists demand-response-capable residential systems. Earlier financing programmes in Germany and tax incentives in Italy also helped establish residential storage markets.

Global net additions of behind-the-meter energy storage capacity (left) by segment, 2020-2031 and (right) by country and segment, 2026-2031



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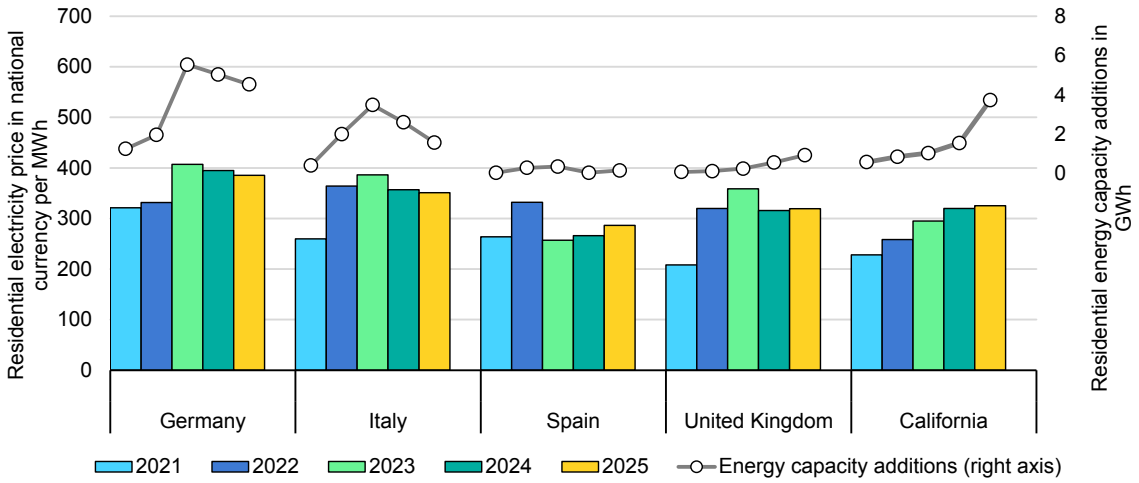
Note: RoW = Rest of world; UK = United Kingdom; US = United States.

Tariff and remuneration frameworks can provide additional indirect incentives. Under California's Net Billing Tariff, exported solar generation is generally remunerated below the retail electricity price, while credits vary according to its value to the grid. This strengthens incentives to store electricity for later self-consumption or export during higher-value periods. By the end of 2024, almost 70% of customers covered by the tariff had paired solar PV with batteries.

The difference between residential electricity prices and remuneration for exported solar generation also shapes storage economics. Where grid electricity prices are high and export remuneration is comparatively low, storing solar generation for later consumption becomes more attractive. Conversely, more moderate residential electricity prices, as in Spain, weaken the economic case for behind-the-meter storage. Nevertheless, comparisons across markets show that electricity prices are only one driver, along with battery costs, policy incentives and the maturity of rooftop solar PV markets.

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Annual residential storage additions and residential electricity prices in selected markets, 2021-2025



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Notes: Residential electricity prices are expressed in local currencies: EUR for Germany, Italy and Spain; GBP for the United Kingdom; and USD for California. Storage additions refer to annual energy capacity additions.

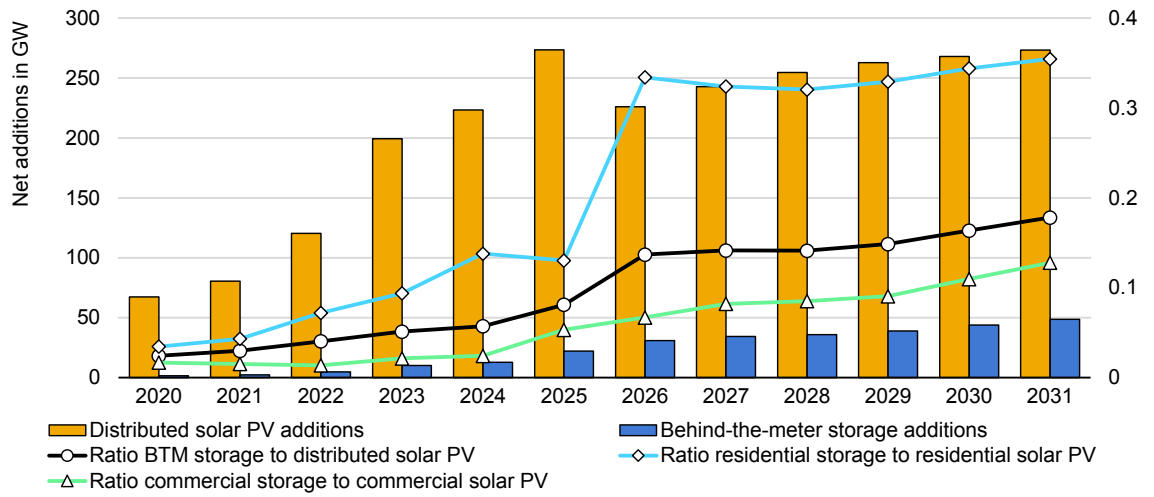
Sources: IEA (2026), End-Use Energy Prices (for Germany, Italy, Spain and the United Kingdom); EIA (2026), Electricity Data Browser (for California).

Declining battery costs and improving storage economics are accelerating the deployment of behind-the-meter storage paired with distributed solar PV. Globally, annual battery additions are projected to rise to around 18% of distributed solar PV additions by 2031. Growth is strongest in the residential segment, where annual battery additions increase from the equivalent of around 13% of rooftop solar PV additions in 2025 to over 35% by 2031, indicating that storage deployment is expanding considerably faster than distributed solar PV.

In mature rooftop solar markets, battery adoption is increasingly becoming the norm rather than the exception. In Germany, around 80% of new residential solar PV systems installed in 2025 included battery storage. Since 2022, annual battery additions have exceeded new residential solar PV additions, reflecting the growing deployment of storage systems alongside existing solar installations as households seek to maximise self-consumption and reduce exposure to retail electricity prices.

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Annual net additions of behind-the-meter power storage capacity and distributed solar PV, 2020-2031



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Notes: BTM = behind-the-meter. The storage-to-PV additions ratio is calculated as annual additions of battery storage power capacity divided by annual solar PV capacity additions. It does not represent the share of individual PV installations paired with batteries.

Next-generation geothermal

Key points

- Next-generation geothermal activity is accelerating, but most enhanced geothermal system (EGS) and closed-loop projects remain under development and are expected to be commissioned after 2031.
- The United States leads commercial-scale EGS project development for power generation, while Europe's pipeline remains smaller and more focused on district heating and industrial heat applications.
- Financing reached nearly USD 2.2 billion in 2025, but growth depends on risk-sharing, permitting reforms and demand for firm low-emissions power and heat.

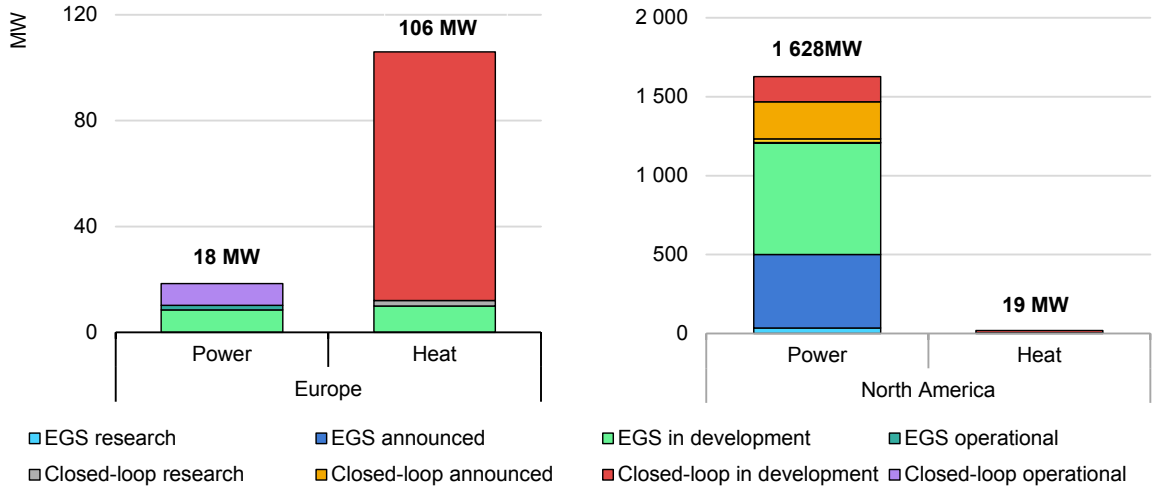
Project activity is accelerating, but most capacity remains in development

North America dominates the project pipeline, led by EGS developments in the United States and closed-loop projects in Canada focused on power generation. Europe's portfolio is smaller and more heat-oriented, with a greater share of projects targeting district heating and industrial direct-use applications. Since most

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of the projects are currently in early development stages and will possibly not come online until after 2031, they are not reflected in the forecast.

EGS and closed-loop geothermal projects at different stages of development in Europe and North America



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Notes: EGS = enhanced geothermal system. North America encompasses the United States and Canada. "In development" covers the exploration, pre-feasibility, feasibility, pre-development, drilling, construction and commissioning stages.

However, installed capacity captures only part of the industry's momentum. Recent announcements have focused on expanding technical capabilities to scale up sector development, including through drilling partnerships, resource assessment and subsurface imaging programmes, AI-driven resource discovery, EGS reservoir stimulation, AI-enabled reservoir modelling and digital twins, supply-chain agreements and technology demonstrations.

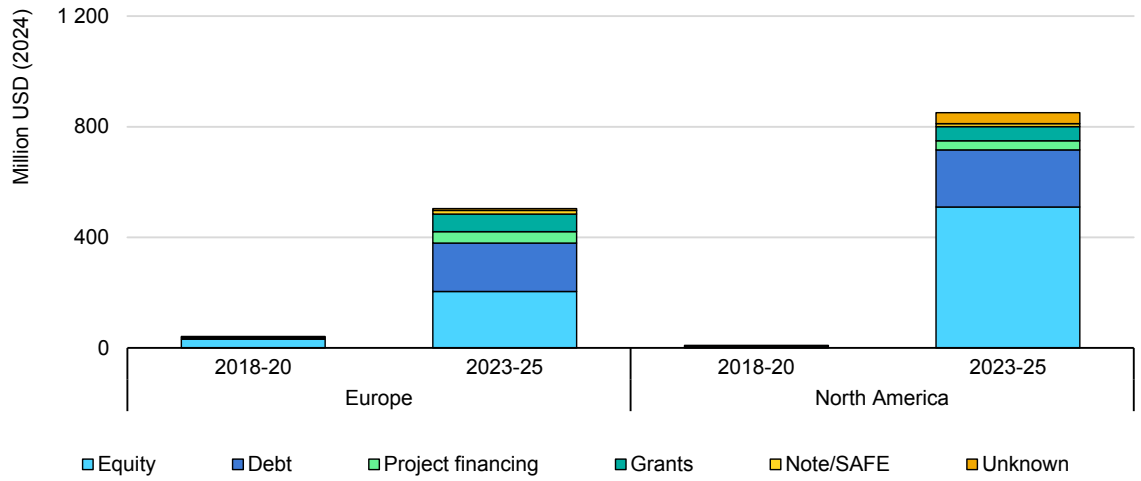
Several developers are also applying next-generation technologies beyond greenfield projects. Projects in Kenya, the United States and China are seeking to retrofit underperforming or non-producing wells, enhance resource recovery, improve well productivity, extend the life of conventional hydrothermal resources and repurpose oil and gas assets. By leveraging existing infrastructure and knowledge, these approaches can lower development costs, reduce subsurface uncertainty and accelerate deployment. All these innovations and partnerships show that the sector remains focused on technology validation, cost reduction and risk mitigation rather than large-scale capacity growth.

Increasing investor confidence is reinforcing this trend. Financing reached nearly USD 2.2 billion in 2025, up from just USD 22 million in 2018. Equity and public funding remain critical for advancing innovation and reducing early-stage risks, with grants accounting for about 9% of global funding, and equity financing declining from around 70% in 2018-20 to just over half in 2023-25.

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The United States leads in the number of awards, while the European Union provides the largest share of support by value.

Next-generation geothermal financing in Europe and North America, 2018-2025

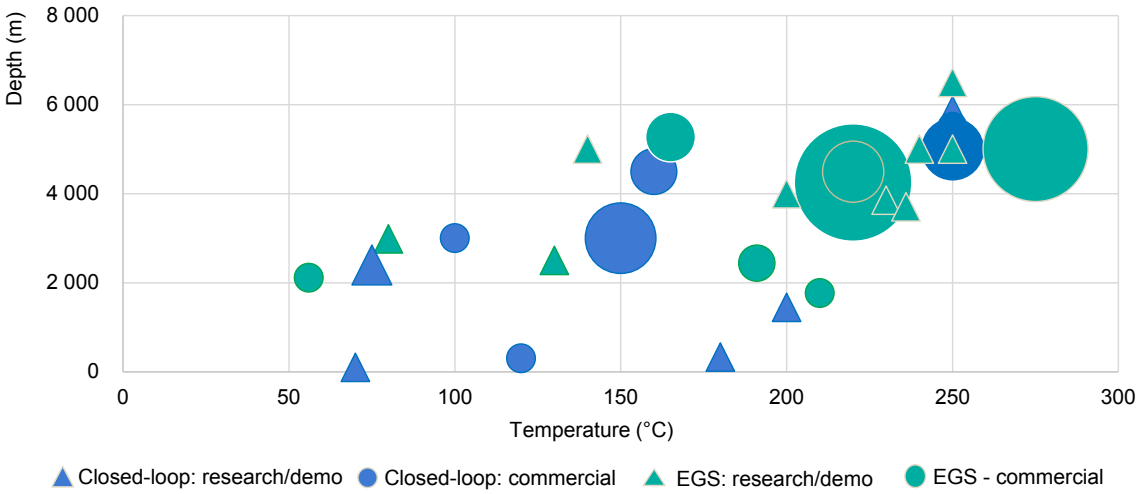


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Notes: North America encompasses the United States and Canada. Note/SAFE: Simple Agreement for Future Equity
Sources: IEA analysis based on data from Cleantech Group (2026); Crunchbase (2026); Underground Ventures (2025).

As projects move closer to commercial deployment, developers are increasingly accessing debt and other commercial funding sources. Debt now accounts for nearly 30% of total funding.

EGS and closed-loop geothermal projects by temperature, depth and development stage



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Notes: EGS = enhanced geothermal system. Graph includes EGS and closed-loop projects only; excludes cancelled/abandoned, on-hold, retired and decommissioned projects. Research/demo projects are shown separately from commercial projects (triangles). Marker size reflects known capacity (MW); projects without capacity data use a minimum marker size. Temperature and depth values are based on available project-level data; missing values are excluded.

Source: IEA (2026), Geothermal Project Database, (accessed 10 June 2026).

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Geothermal temperature-depth distributions reveal the diversity of development pathways across the sector. EGS projects tend to cluster at greater depths and higher temperatures because developers are targeting resources suitable for power generation, while many closed-loop and heat-focused projects operate at lower temperatures and shallower depths, particularly for district heating and industrial heat applications.

Pipeline of commercial projects

Operational capacity remains limited and concentrated in North America and Europe, but project activity is accelerating. Most projects are still at the development, permitting or construction stages. Yet, the scale is increasing rapidly: while only a handful of plants are operating today, several announced projects exceeding 100 MW are targeting start-up before 2030.

Overview of selected next-generation commercial geothermal projects at different stages of development

Country	Project	Developer	Technology	Status	Application	Capacity	Operational
France	Soultz-Sous-Forets	ÉS Géothermie GEIE EMC	EGS	Operational	Power	1.7 MWe	2016
France	Soultz-Sous-Forets - expansion	ÉS Géothermie	EGS	Under development	Heat and power	10 MWth + 3.5 MWe[7]	2030
Germany	Eavor Loop Geret-stried	Eavor	Closed-loop	Partially operational	Heat and power	64 MWth + 8.2 MWe	2025 (heat 2028)
Germany	Eavor Loop Hannover	Eavor, Enercity	Closed-loop	In development	Heat	30 MWth	2028-2029
Switzer-land	Haute-Sorne	Geo-Energie Jura, Geo-Energie Suisse	EGS	Under development	Power	5 MWe	2029
United States	Cape Station Phase I	Fervo	EGS	Partial operation	Power	100 MWe	2027
United States	Cape Station Phase II	Fervo	EGS	Construction	Power	400 MWe	2028
United States	Corsac Station	Fervo, Google, NV Energy	EGS	Pre-construction (permitting)	Power	115 MWe	2030

[7] Preferred development scenario under study; alternative electricity-only (3.5 MWe) and heat-only (26 MWth) configurations are also being evaluated.

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Country	Project	Developer	Technology	Status	Application	Capacity	Operational
United States	Project RED	Fervo, Google	EGS	Operational	Power	3.5 MWe	2023
United States	CC Power	XGS, California Community Power	Closed-loop	Announced	Power	115 MWe	NA
United States	New Mexico project	XGS, Meta, PNM, Baker Hughes	Closed-loop	Under development	Power	150 MWe	2030
United States	Salt Cove	400C Energy	EGS	Pre-construction	Power	20 MWe	NA
United States	Obsidian	Quaise	EGS	Construction	Power	50 MWe	2030
United States	Obsidian - expansion	Quaise	EGS	Announced	Power	250 MWe	NA

Note: The table highlights selected commercial-scale greenfield projects and is not intended to represent the full development pipeline. It excludes research projects.

Policy and market developments

Industry is driving innovation, with rapid advances in drilling, subsurface imaging and reservoir engineering expanding geothermal's technical potential. As projects move towards commercialisation, the challenge is increasingly shifting from technology development to market creation. Future growth will depend not only on continued innovation, but also on policies to reduce project risk, create demand and reward the system value of reliable low-emissions power and heat.

Governments can accelerate deployment through long-term policy frameworks that improve project bankability and investment certainty. Key measures include providing open subsurface data, dedicated geothermal roadmaps, exploration support and financing mechanisms that address drilling and resource risks. Examples include roadmaps in Japan and France; public geological surveys in the United States, Canada and Europe; Japan's government-supported resource assessment programmes; and risk-sharing mechanisms such as France's geothermal guarantee fund and Germany's public-private insurance system.

Permitting reforms are another critical enabler. Many next-generation geothermal projects must still navigate regulatory frameworks originally designed for mining, hydrocarbons or conventional geothermal development. Streamlined permitting initiatives in the United States and Hungary, dedicated geothermal authorities in Kenya and technology-specific regulatory frameworks can shorten development timelines while recognising the distinct characteristics of hydrothermal, EGS and closed-loop systems.

Demand-creation priorities are likely to differ by region. In power markets such as California's, policies are focused on recognising the value of firm, dispatchable

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low-emissions power through targeted procurement and other mechanisms that reward reliability, flexibility and energy security. In regions where heating is the strongest near-term opportunity, priorities include district heating and industrial heat expansion; heat planning; and standardisation of long-term heat purchase agreements that provide demand certainty and support investment in domestic geothermal resources.

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Chapter 2. Renewable transport

Summary

- Between 2025 and 2031, renewable energy use in transport is forecast to increase 60%, to nearly 9 EJ, meeting 6% of global transport energy demand.
- Renewable electricity in transport accounts for 45% of this growth, driven by China and Europe. Road biofuels provide a further 35%, led by ethanol in Brazil and India, renewable diesel in the United States, and biodiesel in Indonesia and Brazil. Marine and aviation biofuels, biomethane, renewable hydrogen and hydrogen-based fuels account for the remaining 20%.
- Energy security concerns and higher oil prices stemming from the current conflict in the Middle East raise the 2030 liquid biofuel forecast by 40% from last year's forecast, led by ethanol growth in Brazil and India, renewable diesel growth in the United States, and biodiesel growth in Southeast Asia.
- Total liquid biofuel demand in transport increases nearly 30% on a volumetric basis between 2025 and 2031, from 198 to 251 billion litres per year in the main case. Road transport accounts for nearly 85% of this growth, with the remainder coming from rising use in aviation and marine transport.
- Full implementation of announced targets and mandates could raise global liquid biofuel demand to just over 330 billion litres by 2031, nearly 35% more than in the main case. Achieving this level would require stronger support for production capacity, infrastructure and sustainable feedstock supplies.
- In road transport, renewable energy demand expands 60% to almost 9 EJ by 2031, covering 9% of the road sector's total final energy use, and accounts for 90% of renewable energy growth in transport. In the accelerated case, it rises to 11.5 EJ, covering 11% of the road sector's final energy use.
- Marine biodiesel demand more than doubles to nearly 2 billion litres per year by 2031, making up less than 1% of global marine fuel use, and accounts for 1% renewable energy growth in transport. In the accelerated case, it reaches more than 12 billion litres per year, covering 4% of marine fuel use.
- Biojet fuel use increases nearly fivefold to 10 billion litres per year by 2031, covering 2% of aviation fuel demand, and accounts for 9% renewable energy growth in transport. In the accelerated case, it reaches nearly 22 billion litres per year, covering just over 4% of aviation fuel demand.
- Feedstock demand rises 30% in the main case, from 650 Mt/yr in 2025 to more than 850 Mt/yr in 2031. It reaches 1 Gt/yr in the accelerated case.

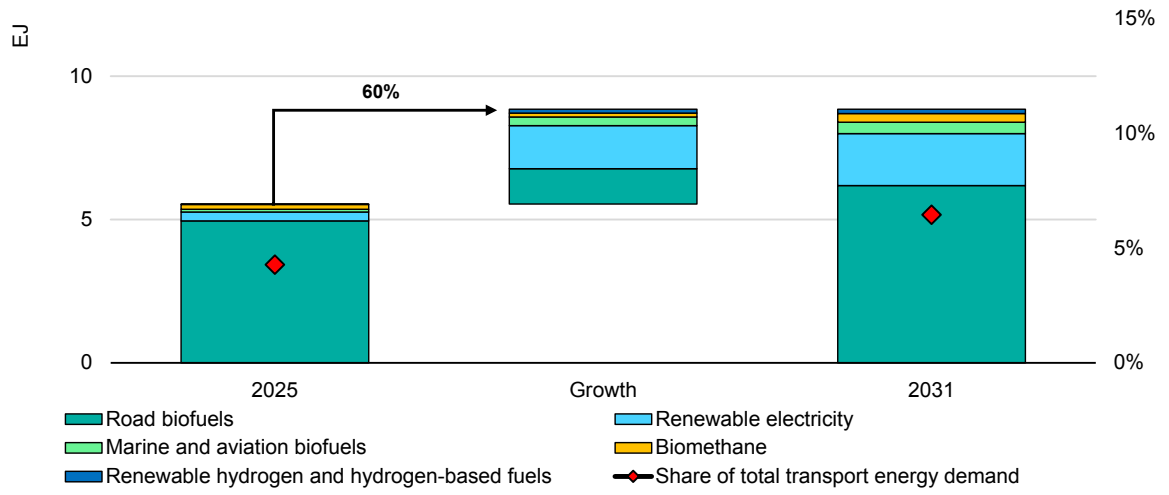
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Global forecast summary

Renewable energy use in transport increases 60% as demand for electric vehicles and liquid biofuels expands

Renewable energy consumption in transport is forecast to increase from 5.5 EJ in 2025 to nearly 9 EJ in 2031, covering 6% of global transport energy demand. Growth results from efforts in multiple countries to strengthen energy security, reduce fossil fuel import dependence, meet emissions reduction targets and create economic opportunities through greater renewable energy deployment.

Renewable energy use and share in transport demand, main case, 2025-2031



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Notes: Renewable electricity estimates are based on the renewable electricity forecast and EV energy use in the *Global EV Outlook 2026*. The energy share of transport demand is based on total global transport energy demand in the *World Energy Outlook 2026* STEPS scenario.

Sources: IEA (2026), Global EV Outlook 2026; IEA (forthcoming), World Energy Outlook 2026.

Renewable electricity accounts for 45% of renewable transport growth, climbing from 0.3 EJ in 2025 to 1.8 EJ by 2031. This rise reflects a projected increase in the share of renewables in electricity generation from 33% in 2025 to 43% in 2031 and rapid electric vehicle deployment, with EVs accounting for one-quarter of new car sales in 2025 alone. China contributes half of the growth, owing to rapid deployment of light-duty passenger electric vehicles, medium- and heavy-duty electric trucks and domestic battery supply chains. Europe accounts for an additional 30%, reflecting the increasing availability of affordable electric vehicles in the region.

Liquid biofuels in road transport supply an additional 35% of renewable transport growth from 4.9 EJ (195 billion litres per year or 3 352 kb/d) in 2025 to 6.2 EJ

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(240 billion litres per year or 4 130 kb/d) in 2031. Blending mandates and rising transport fuel consumption underpin this expansion. Brazil (40%) and India (25%) lead ethanol growth, while the United States (65%) and Indonesia (15%) lead renewable diesel growth, and Indonesia (70%) and Brazil (20%) lead biodiesel expansion.[8]

The use of liquid biofuels in marine and aviation transport contributes an additional 10% of renewable energy growth in transport, expanding from 0.1 EJ (2.8 billion litres per year or 49 kb/d) in 2025 to 0.4 EJ (12 billion litres per year or 201 kb/d) in 2031. In marine transport most of this growth (80%) is in the European Union, from marine biodiesel as the European Union is the only jurisdiction to have long-term emission reduction targets for the sector. In aviation transport, biojet fuel[9] growth is strongest in Europe (45%), owing to long-term sustainable aviation fuel (SAF) mandates in the United Kingdom and the European Union, followed by the United States (25%) due to federal and state-level policies and incentives.

Biomethane, renewable hydrogen and hydrogen-based fuels make up the remaining 10% of renewable energy growth in transport. Biomethane demand in road transport rises from nearly 0.2 EJ (4.6 bcm) in 2025 to 0.3 EJ (8.4 bcm) in 2031. India leads this growth (30%), supported by rapid expansion of its gas-fuelled vehicle fleet, guaranteed offtake agreements with publicly owned oil marketing companies and financial support for biomass aggregation and infrastructure development. The United States follows (25%), as the federal Renewable Fuel Standard (RFS) and state-level low-carbon fuel standards allow biomethane to generate credits, improving the economic case for its use in natural gas vehicles. Growth in France (10%), the United Kingdom (10%), and Italy (10%) results from long-standing, and growing, support for biomethane use and distribution infrastructure.

Meanwhile, consumption of renewable hydrogen and its derivatives (e.g. ammonia, e-methanol and e-SAF) increases from 0.01 EJ in 2025 to 0.2 EJ in 2031 with most growth driven by demand for hydrogen in road transport. China leads this growth (35%) as it leverages its abundance of renewable electricity to produce renewable hydrogen and some emerging hydrogen-based fuels (i.e. e-fuels), followed by Korea (10%), owing to long-term policy commitments and competitive auctions, and Europe (5%), due to the Renewable Energy Directive (RED) requirement for renewable fuels of non-biological origin (RFNBOs) for

[8] Biodiesel is produced using a process known as transesterification, where feedstocks such as vegetable oils and waste oils react with alcohols in the presence of a catalyst to produce a fuel that is typically blended in limited quantities with conventional diesel. Renewable diesel is produced using a process known as hydrotreatment, where similar feedstocks react with hydrogen at high temperatures to produce a fuel that is chemically similar to petroleum diesel and can be used as a direct replacement.

[9] Biojet fuel is a sustainable aviation fuel (SAF) produced primarily from biomass feedstocks. SAF can also be produced from low-emissions hydrogen and carbon dioxide (e.g. synthetic fuels). This chapter only includes SAF produced from biomass (e.g. biojet fuel).

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transport, sub-targets for synthetic aviation fuels under the UK and EU SAF mandates, and the EU FuelEU Maritime regulation.

Energy security priorities raise liquid biofuel growth 40% above last year's forecast

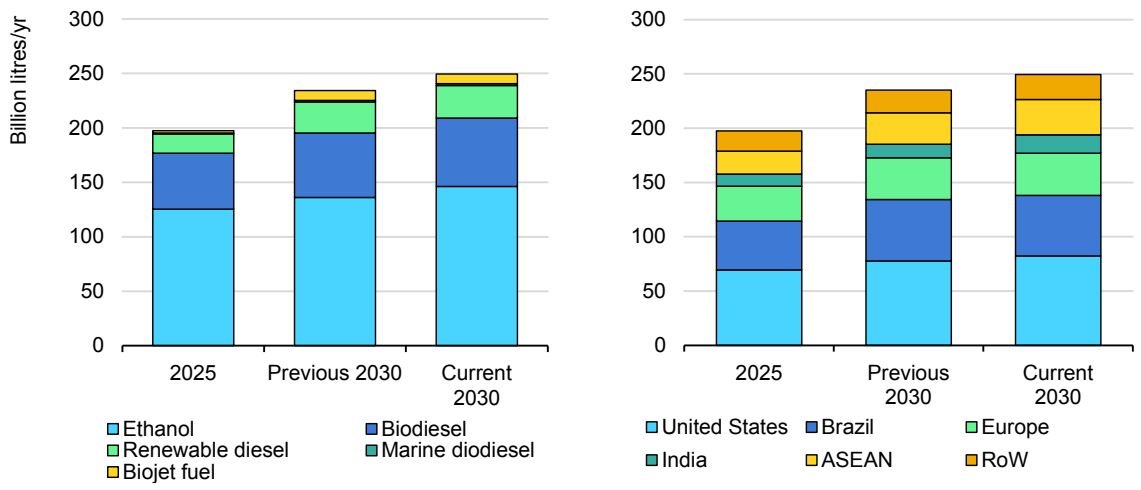
The current conflict in the Middle East has disrupted oil supplies, prices and key shipping routes globally, causing attention to turn more strongly towards sustainable fuels that can be produced in a wider range of locations, often using domestic or regionally available feedstocks. Countries around the world are therefore accelerating the implementation of new and previously announced liquid biofuel mandates, as energy security and affordability concerns raise the urgency of reducing exposure to oil market volatility in the short, medium and long term.

- **Indonesia** has reaffirmed its commitment to E10 blending by 2028 and announced further increases to its biodiesel mandate from B40 to B50 and a renewable diesel target of 5%, rising to 10% by 2028.
- **Malaysia** has announced it will expand biodiesel blending from B10 to B15.
- **Viet Nam** has announced that consumers can no longer buy unblended gasoline and must purchase E5 or E10 blends.
- **Brazil** has increased ethanol blending from 30% to 32%, accelerating progress towards its Fuel of the Future ethanol blending targets.
- **Argentina** has raised the voluntary limit of ethanol blending from E12 to E15.
- **Paraguay** has increased mandatory biodiesel blending from B5 to B8-10.
- **The United States** has extended waivers to allow the sale of E15 over the summer months (traditionally prohibited in several states due to concerns about fuel vapour pressure impacting air quality in warm weather), but it will not likely be available nationwide due to storage and distribution infrastructure limitations at most gas stations. In addition, electricity has been removed as a credit-generating pathway under the federal RFS, while renewable fuel volume obligations for 2026 and 2027 have been increased from previously proposed levels, primarily to support farmers and boost demand for domestically produced feedstocks.

These market dynamics and policy changes result in a 40% volumetric increase (16 billion litres per year or 272 kb/d) in total liquid biofuel demand growth by 2030 compared with last year's forecast. Ethanol accounts for 50% of this upward revision, driven by India's early achievement of E20 blending (five years ahead of schedule) as well as adjustments to federal US waivers for ethanol and increases to US RFS obligations. Renewable diesel provides a further 30%, again supported by higher US RFS volumes. Biodiesel and marine biodiesel account for the remainder, reflecting efforts to reduce fossil fuel import dependence in Southeast Asia and the continued implementation of the EU's FuelEU Maritime regulations.

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Forecast revision to liquid biofuel demand by fuel and region, main case, 2025-2030



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Notes: ASEAN = Association of Southeast Asian Nations. RoW = rest of world. Demand changes were estimated based on the forthcoming IEA *World Energy Outlook 2026* and policy changes to mid-July 2026. Fuel demand changes cover biofuel demand resulting from transport fuel demand differences between IEA forecasts. The forecast revision period covers growth over 2026-2030, since the *Renewables 2025* forecast horizon ends in 2030.

Road transport leads liquid biofuel demand while aviation and marine gain momentum

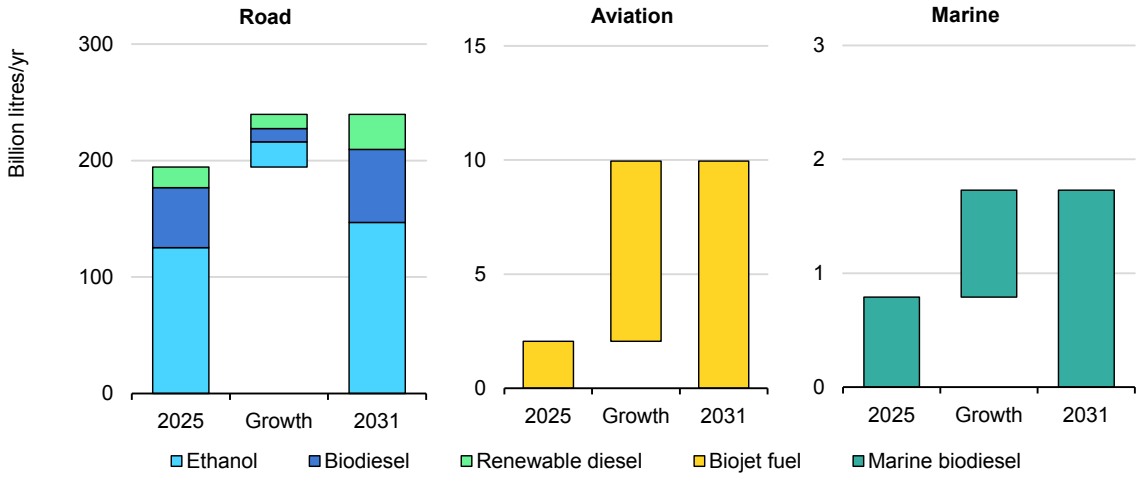
Total liquid biofuel demand in transport climbs nearly 30% on a volumetric basis from 198 billion litres (3 401 kb/d or 5 EJ) in 2025 to 251 billion litres (4 331 kb/d or 6.6 EJ) in 2031. Road transport accounts for nearly 85% of this growth, with the remainder coming from rising use in aviation and marine transport. Liquid biofuels in road transport make up nearly 85% of this increase, as ethanol, biodiesel and renewable diesel consumption all continue to grow. Increases to mandates in Brazil, Indonesia, Viet Nam, Malaysia, and Thailand, and higher renewable fuel volume obligations under the US RFS drive much of this growth. GHG intensity reduction requirements for transport fuels in Canada and Europe also continue to enlarge demand in road transport as liquid biofuel blending remains a key pathway to meet regulatory obligations.

Aviation and maritime transport make up the remaining roughly 15%. Demand for SAF continues to grow, driven primarily by the ReFuelEU Aviation regulations, which entail 6% SAF by 2030, and the UK SAF mandate requiring 10% by 2030. Mandates, supply-side obligations, and indicative and emissions-reduction based targets in several other countries such as Brazil, Japan, Singapore, India, Malaysia, Indonesia and Korea also drive demand globally. Meanwhile, demand for marine biodiesel stems primarily from the EU FuelEU Maritime requirements to reduce ships' well-to-wake GHG intensity 6% by 2030 and 14.5% by 2035, as

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it is one of the few commercially available low-emissions fuels. Demand in the Asia Pacific region also rises because the region services ships headed for Europe.

Liquid biofuel demand by transport mode, main case, 2025-2031



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Fully implemented policies could increase liquid biofuel demand nearly 35% more by 2031

In an accelerated case with announced targets, mandates and supporting policies fully implemented, global liquid biofuel demand could increase to 333 billion litres (5 740 kb/d or 9.0 EJ), nearly 35% more than in the main case. One-third of this additional growth stems from continued support for higher ethanol blends in the United States, Brazil and India.

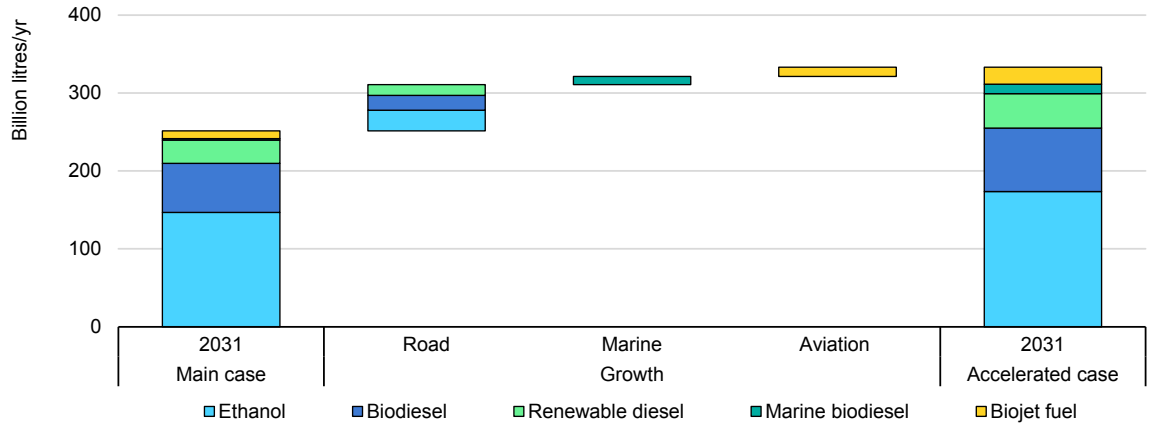
Biodiesel and renewable diesel each contribute roughly 20% owing to continued US RFS support for biodiesel and renewable diesel, and to higher biodiesel blending in Southeast Asia (in countries such as Indonesia and Malaysia). Remaining growth results from the implementation of SAF mandates in several regions, such as the United Kingdom, the European Union, Brazil, India, Korea, Singapore, Indonesia and Malaysia, and from potential implementation of the International Maritime Organization (IMO) Net-Zero Framework (voting was delayed from 2025 to December 2026).

Accelerated growth in liquid biofuels would keep progress in line with the levels required to meet the COP30 Belém 4X Pledge on Sustainable Fuels – a global agreement endorsed by 32 countries to increase deployment of sustainable liquid and gaseous fuels by four times by 2035. However, achieving additional growth would entail further support across the liquid biofuel supply chain in many regions.

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Accelerating the uptake of commercially available liquid biofuels would require measures that continue to incentivise their use, such as tax breaks on fuels blended with higher shares of liquid biofuels to reduce prices for consumers, or improvements to fuel standards.

Liquid biofuel demand differences between the main and accelerated cases, 2031



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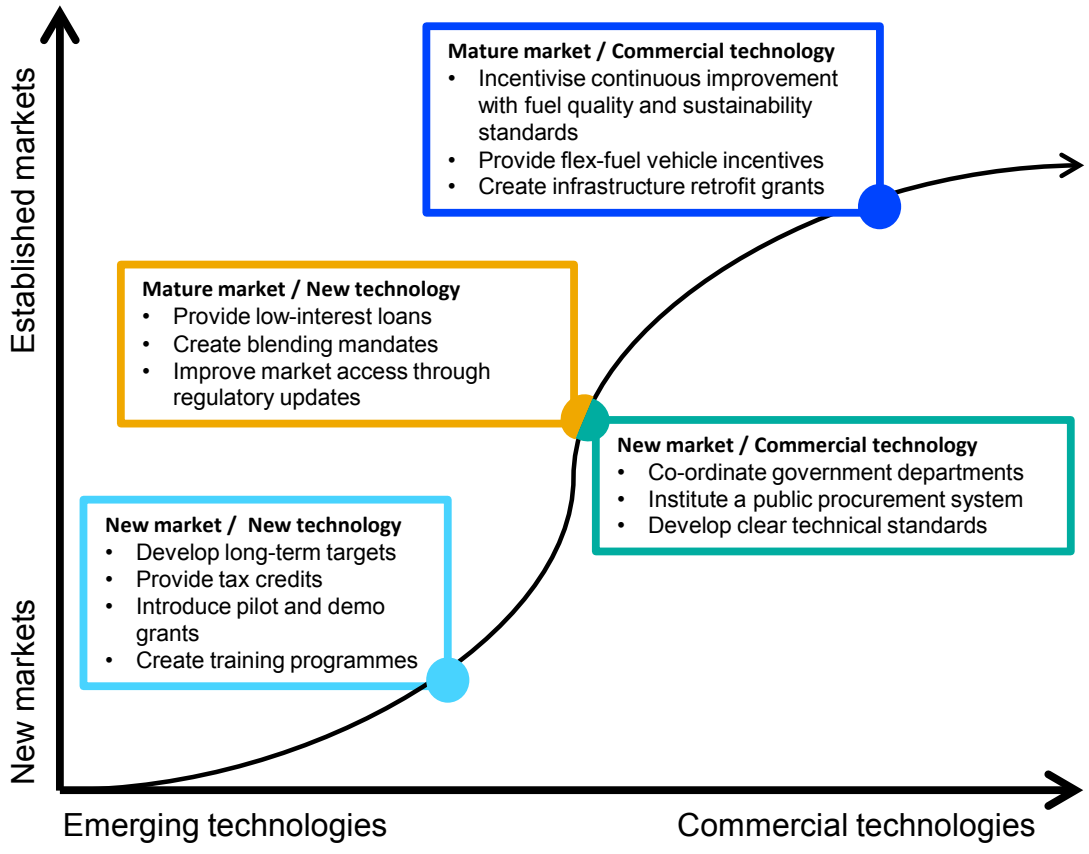
Scaling up new and emerging liquid biofuel production would also require the development of production capacity, with policy measures to derisk technology and large capital investments (e.g. grants for pilot and demo-scale technologies and low-interest loans for first-of-a-kind facilities), and strategies to support initial and sustained demand (e.g. public procurement agreements and amendments to regulations to ensure market access for new fuels and technologies). In addition, regulatory and financial measures should be “technology-open” to ensure that all fuels and production pathways are included regardless of technological maturity, guaranteeing equitable access to fuel markets and further expediting sustainable liquid fuel growth.

Securing access to adequate supplies of affordable and sustainable feedstocks will also be critical, likely necessitating the integration of broader biomass strategies into long-term targets and planning. Measures such as improving yield optimisation, intercropping, cultivating marginal land, forest management practices to mitigate wildfire risk, and leveraging changing market dynamics in traditional biomass value chains (e.g. using less low-grade forest biomass in the pulp and paper industry as demand for these products declines) can help expand feedstock availability – as has already been demonstrated by several countries, including Brazil, Kenya and Canada. Similarly, enlarging distribution and storage infrastructure would require additional support through long-term investments and other financial mechanisms to ensure that fuel blenders, distributers and end users can manage liquid biofuel blending increases.

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Achieving this growth will require a coherent policy framework that combines long-term demand signals with fiscal and investment support, and robust technical and sustainability standards. Strong policy frameworks that can be replicated include Brazil's Fuel of the Future Law, India's National Policy on Biofuels, the US federal Renewable Fuel Standard and Clean Fuel Production Tax Credit, Canada's Energy Innovation Program, Clean Fuels Fund and Clean Fuel Regulations, and the EU's Renewable Energy Directive, ReFuel Aviation, FuelEU Maritime and Sustainable Transport Investment Plan.

Selected policies to scale up liquid biofuel growth by market maturity and technology readiness



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Notes: The figure highlights selected policy examples from around the world that have been used to scale up sustainable fuel growth based on production pathway and market maturity and is not meant to be exhaustive. Many of these measures can be used continuously to support the scale-up of new fuels or further deploy already-commercialised ones.
Source: Adapted from IEA (2025), Delivering Sustainable Fuels.

Oil-based feedstock use grows the fastest as demand rises for biodiesel, renewable diesel and biojet fuel

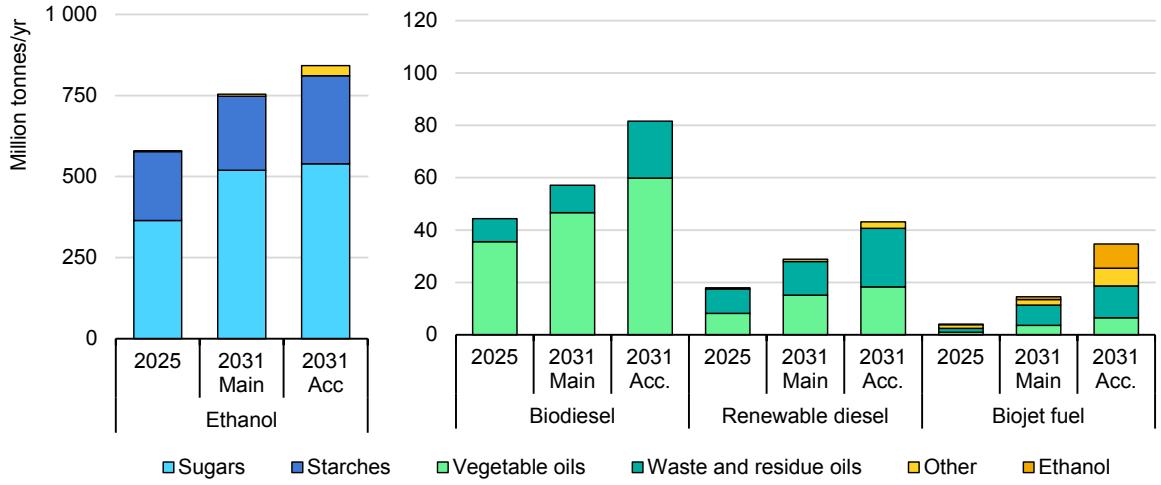
In the main case, feedstock demand increases 30% between 2025 and 2031, from 650 million tonnes per year to more than 850 million tonnes per year. Sugars and

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starches make up more than four-fifths of this growth, driven by rising ethanol demand, mainly in Brazil, India and the United States.

Vegetable oils, waste oils and fats, and other feedstocks meet remaining growth in global feedstock demand, but oil-based feedstocks record the fastest increase over the forecast period. Demand grows across all regions, but the underlying drivers vary. In North America, higher renewable fuel obligations under the US RFS, as well as production incentives, boost demand for these feedstocks to produce renewable diesel and biojet fuel. In Asia Pacific, higher biodiesel and renewable diesel consumption and blending rates in Indonesia and Malaysia, together with expanding biojet fuel production in China, drive growth. In South America, rising biodiesel blending in Brazil underpins additional demand, while in Europe, SAF mandates and the FuelEU Maritime regulations increase the need for feedstocks to produce biojet fuel and marine biodiesel.

Liquid biofuel feedstock demand by fuel type, main and accelerated cases, 2025-2031



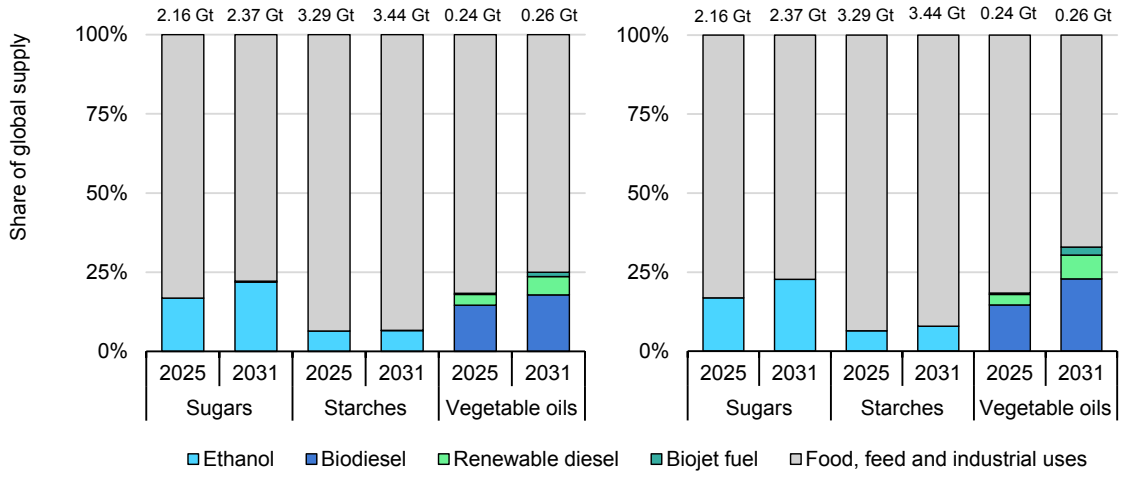
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Notes: Acc. = accelerated case. “Sugars” includes sugarcane, molasses and sugar beets. “Starches” covers maize, wheat, rice, cassava and other starches. “Vegetable oils” refers to soybean, rapeseed, palm and other vegetable oils. “Waste and residue oils” represents used cooking oil, tallow and palm oil mill effluent and other oils. “Other” includes woody wastes and residues.

In the accelerated case, feedstock demand rises a further 15% above the main case, reaching 1 gigatonne per year by 2031. Sugar and starch use still grows the most, although this share declines to 65% as demand diversifies across feedstock types. Brazil, India and the United States continue to drive demand for sugar- and starch-based feedstocks through higher ethanol use, supported by blending mandates, flex-fuel vehicle deployment and continued policy support for liquid biofuels.

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Liquid biofuel feedstock demand and shares of total global feedstock supply, main case (left) and accelerated case (right), 2025 and 2031



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Notes: GT = Gigatonne. Values at the top of the columns are total feedstock demand. "Sugars" includes sugarcane, molasses and sugar beets. "Starches" refers to maize, wheat, rice, cassava and other starches. "Vegetable oils" indicates soybean, rapeseed, palm and other vegetable oils.

Compared with the main case, oil-based feedstocks account for a larger share of demand growth in the accelerated case. Demand for vegetable oils, waste oils and fats rises as countries expand biodiesel, renewable diesel and biojet fuel production to meet road transport mandates, SAF targets, Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA) requirements and, if adopted, the IMO Net-Zero Framework. Intensifying competition for these feedstocks, particularly vegetable oils, is likely to increase the need for new supply sources and conversion pathways. Emerging technologies such as the alcohol-to-jet (ATJ) method, which can leverage established ethanol supply chains, and the Fischer-Tropsch process using underutilised feedstocks such as low-grade wood residues, could help diversify feedstock supplies and reduce competition for traditional feedstocks.

Robust sustainability frameworks are essential to scale up liquid biofuel growth

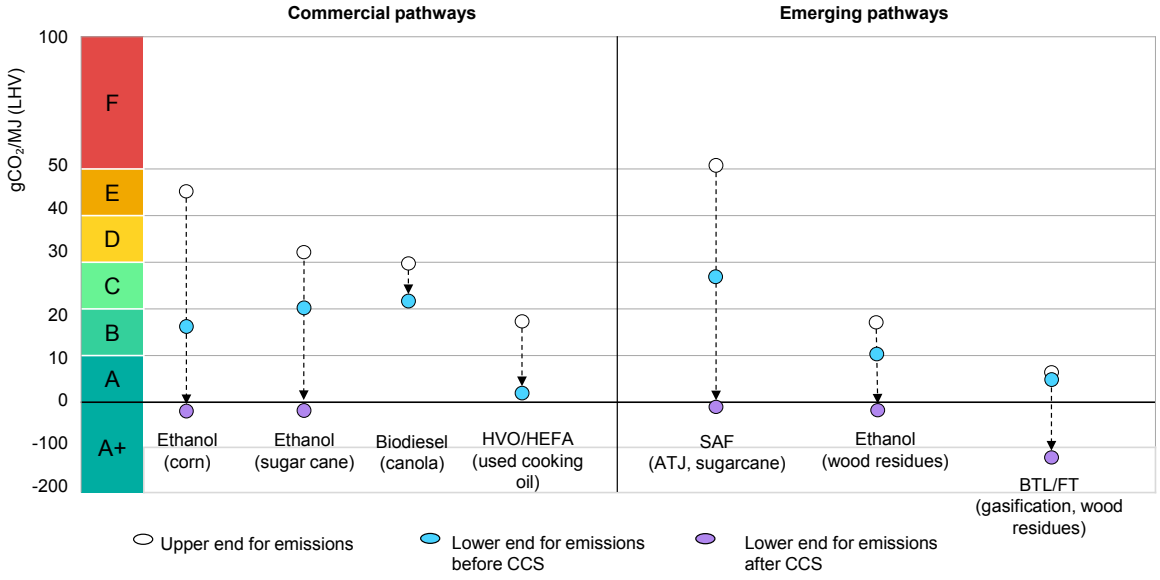
The emissions reduction potential of liquid biofuels is significant for all forms of transport, but sustainability remains the foundation for current and future demand. Lifecycle GHG emissions ranges show that the emissions reduction potential of these fuels varies across fuel pathways, depending on feedstock, production process, and supply chain development. Robust sustainability frameworks are therefore essential to ensure that rising consumption corresponds to verified emissions reductions without adverse land, water or biodiversity impacts.

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Previous IEA analysis on carbon accounting for sustainable liquid biofuels and on common criteria for liquid and gaseous sustainable fuels suggests that several key measures can help further reduce lifecycle emissions, ranging from sustainable farming practices to using renewable energy during production, to applying carbon capture, utilisation and storage. Such emission reductions have been proven in several countries, particularly for ethanol production, with well-designed policies that aim to continuously improve supply chain efficiency and reduce emissions.

Most importantly, the Delivering Sustainable Fuels report, which underpins the Belém pledge to quadruple sustainable fuel production and use, argues that by 2035, most existing and emerging fuel pathways could achieve very low lifecycle GHG intensity (g CO_2-eq/MJ). They may even deliver net carbon removal in some cases, provided that performance-based policies that drive continuous improvements are implemented.

Lifecycle GHG emission ranges for selected sustainable liquid biofuel production pathways



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Notes: LHV = lower heating value. HVO = hydrotreated vegetable oil. HEFA = hydroprocessed esters and fatty acids. CCS = carbon capture and storage. SAF = sustainable aviation fuel. ATJ = alcohol-to-jet fuel. BTL = biomass-to-liquid. FT = Fischer-Tropsch. GHG intensities for the biofuel pathways are from R&D GREET 2024 Rev1. Direct land-use change is included, but indirect is excluded. CCS assumptions and other pathways are based on IEA analysis. Removals through soil carbon accumulation are possible for some of the pathways but are not considered in this figure. All values are for lower heating value. Emissions from transport and distribution of final fuel to end user are 2 g CO_2/MJ for liquid biofuels fuels.
Source: Adapted from IEA (2025), Delivering Sustainable Fuels.

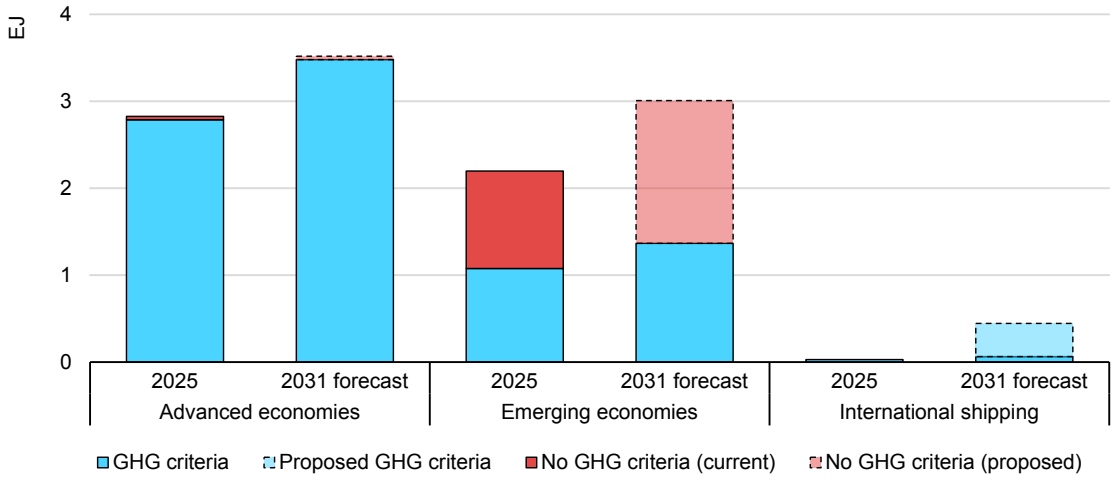
Performance-based standards and GHG thresholds currently cover around 80% of global liquid biofuel demand. The United States, Brazil, Canada, Germany, Sweden and the International Civil Aviation Organization (ICAO) use such frameworks to reduce the carbon intensity of existing fuels while supporting

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demand for sustainable alternatives. The IMO's proposed Net-Zero Framework also includes a global fuel standard for international shipping.

In other markets such as Indonesia and Malaysia, sustainability verification often relies on third-party certification such as the International Sustainability and Carbon Certification (ISCC) initiative or the Roundtable on Sustainable Biomaterials (RSB). These systems can help producers meet export market requirements or comply with international strategies, such as the ICAO Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA), but they do not always provide the same domestic policy basis for assessing emissions reductions and broader sustainability impacts.

Liquid biofuel demand covered by legislative GHG criteria, 2025 and 2031



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Notes: "GHG criteria" includes performance-based GHG intensity targets, incentives and GHG thresholds. "Proposed GHG criteria" includes the IMO's proposed global fuel standard.

Without domestic sustainability frameworks, countries may struggle to verify the environmental benefits of liquid biofuels and manage potential unintended adverse impacts from production, distribution and use. This could slow liquid biofuel growth by weakening investor confidence, particularly where sustainability practices are unclear. Export opportunities may also be limited, as trade partners and international frameworks increasingly require evidence that fuels deliver verified emissions reductions and meet wider sustainability criteria.

For countries aiming to expand domestic liquid biofuel production and leverage export opportunities as demand grows globally, the development of sustainability frameworks will be important. Drawing on established best practices, governments can adapt performance-based systems to domestic conditions while ensuring compatibility with international requirements. This would support sustainability,

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provide clearer signals for investors, support market access and reduce the risk of future growth being constrained by uncertainty over environmental practices and performance.

Road

Key points

- Renewable energy demand in road transport grows 60% to almost 9 EJ by 2031, covering 9% of the road sector's total final energy consumption, and accounts for 90% of renewable energy growth in transport.
- Renewable electricity makes up more than half of this growth, supported by EV deployment globally. Liquid biofuels constitute most of the remaining growth as demand for ethanol, renewable diesel and biodiesel increase.
- In the accelerated case, renewable energy use in road transport reaches 11.5 EJ to cover 11% of sector demand by 2031. Renewable electricity still accounts for the largest single share of growth, followed by liquid biofuels with increasing demand for all fuels in several regions.

Forecast

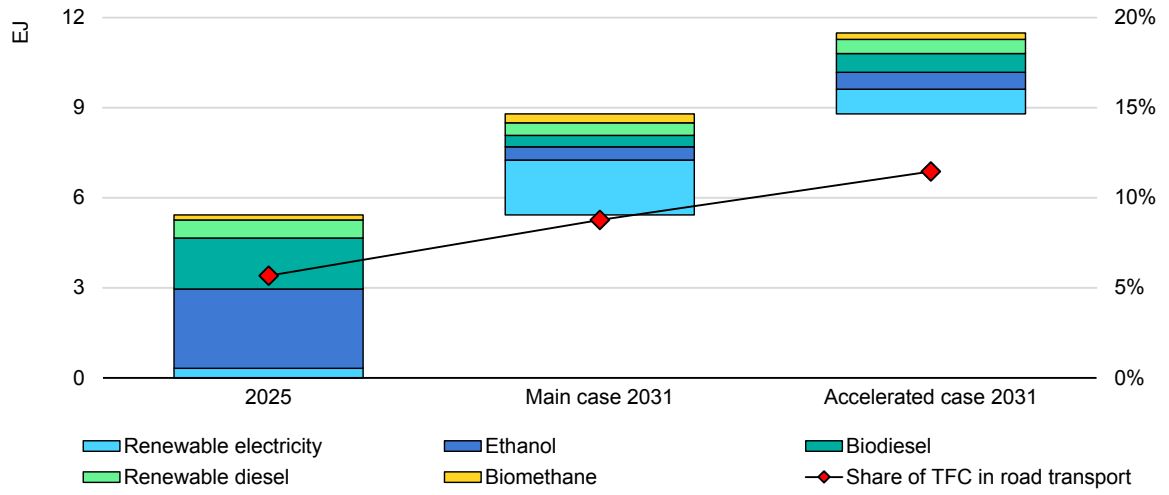
Demand for renewable energy in road transport is expected to grow 60% from roughly 5.5 EJ in 2025 to almost 9 EJ by 2031 in the main case, covering 9% of the road sector's total final energy consumption and accounting for 90% of renewable energy growth in transport. Renewable electricity demand for electric vehicles accounts for 55% of this growth, climbing from just under 0.3 EJ in 2025 to 1.8 EJ by 2031. The increase stems from continued large-scale deployment of electric cars and trucks in China and accelerated uptake throughout Europe, North America and other parts of Asia. Affordable two- and three-wheeled EVs and passenger light-duty vehicles become more widely available, and electrified trucks are increasingly cost-competitive.

Liquid biofuels provide an additional 35% of renewable road transport growth from 4.9 EJ (195 billion litres per year or 3 352 kb/d) in 2025 to 6.2 EJ (240 billion litres per year or 4 130 kb/d) in 2031. Consumption of liquid biofuels rises the most in Brazil (25%), the United States (25%), Indonesia (25%) and India (10%) as total fuel demand increases and as mandates, financial incentives and low-carbon fuel standards continue to support these fuels. Biomethane makes most of the remaining growth. Biomethane climbs from just over 0.2 EJ (4.6 bcm) in 2025 to

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0.3 EJ (8.4 bcm) in 2031, with the greatest rises in India (30%), the United States (25%), and France, the United Kingdom and Italy (30%) owing to financial support and low-carbon fuel standards.

Renewable energy demand in road transport, main and accelerated cases, 2025-2031



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Notes: TFC = total final consumption. Renewable electricity use is based on renewable electricity shares for each region, consistent with this report's forecast and total electricity demand for plug-in hybrids and battery electric vehicles. Road TFC includes gasoline, diesel, natural gas, ethanol, biodiesel, renewable diesel, biogases and electricity.

Ethanol remains the main source of liquid biofuel growth in road transport, climbing from 125 billion litres per year (2 160 kb/d) in 2025 to just over 146 billion litres (2 530 kb/d) in 2031. South America accounts for just over 40% of this growth, as Brazil has raised its ethanol blending requirement from E30 to E32 and Argentina has increased voluntary blending from E12 to E15 to reduce consumer fuel prices amid elevated gasoline prices due to the current conflict in the Middle East.

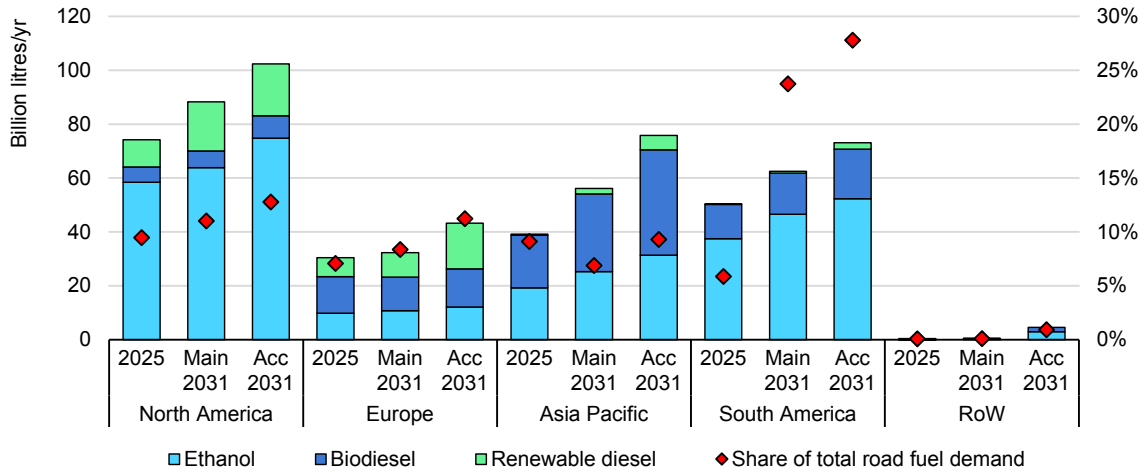
An additional roughly 25% of ethanol growth comes from the Asia Pacific region, with several countries having reached or committing to blending targets. In 2025, India met its E20 blending target five years ahead of its 2030 schedule and is anticipated to maintain this level of blending, although concerns have been raised about how the rapid scale-up of higher ethanol blends will impact vehicle components. Meanwhile, to further reduce their fossil fuel imports, Indonesia and Japan have announced or recommitted to E10 blending targets before the end of the decade, and Viet Nam has declared that consumers can no longer buy unblended gasoline and must instead purchase E5 or E10 blends.

North America accounts for most of the remaining expansion. In the United States, summer waivers allowing E15 sales kept ethanol demand steady, lowered gasoline prices and provided an additional market for farmers to sell domestic feedstocks. However, wider uptake remains restricted by fuel station infrastructure

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limitations in the short term, as some retailers will require storage and handling upgrades to offer higher ethanol blends. In Canada, continued implementation of the Clean Fuel Regulations, together with provincial blending mandates and low-carbon fuel standards, is expected to drive further growth in domestic ethanol demand by the end of the decade.

Liquid biofuel demand in road transport, main and accelerated cases, 2025-2031



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Notes: Acc = accelerated case. RoW = rest of world.

Renewable diesel expansion follows ethanol, growing from nearly 18 billion litres per year (306 kb/d) in 2025 to 30 billion litres per year (517 kb/d) in 2031. North America, primarily the United States, accounts for two-thirds of this growth, owing mainly to increases in renewable diesel demand under the RFS's higher volumetric obligations for biodiesel and renewable diesel, while Canada's Clean Fuel Regulations drive small additional demand.

The Asia Pacific region and Europe account for most of the remaining renewable diesel growth. Indonesia makes some progress towards meeting its initial 10% blending target by 2028; however, it will likely have to reduce its feedstock exports and/or find additional sustainable feedstocks as biodiesel and biojet fuel production are likely to compete for the same feedstocks as those needed for renewable diesel. Europe's demand for renewable diesel also grows as EU countries look to meet emission reduction targets under RED III.

Biodiesel grows over 20% from almost 52 billion litres per year (887 kb/d) in 2025 to nearly 63 billion litres per year (1 083 kb/d). The Asia Pacific region makes up four-fifths of this growth, particularly Indonesia, where biodiesel demand continues to rise as overall diesel consumption expands, even though blending remains at B40 with further progress towards B50 limited by current production capacity.

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Additional expansion comes from Malaysia's recent biodiesel increase from B10 to B15 blending and Thailand's fuel subsidies to support consumption as diesel prices climb.

South America and North America provide the remaining growth, with Brazil incrementally raising biodiesel blending from B15 to B16 by 2031, despite delays in testing, and the US RFS boosting biodiesel and renewable diesel fuel volume obligations. While this is expected to primarily support renewable diesel growth, it will also subsequently increase demand for biodiesel.

In the **accelerated case**, renewable energy demand in road transport could be 30% higher than in the main case, reaching 11.5 EJ by 2031 and raising its share of total final energy consumption in the sector to 11%. Renewable electricity use in road transport remains the single largest source of additional growth, with continued consumer incentives, increased access to affordable EVs, and investment in charging and manufacturing infrastructure driving stronger EV deployment. Combined, liquid biofuels provide most of the remaining increase as countries accelerate the implementation of higher blending rates and supporting policies.

Ethanol, renewable diesel and biodiesel each contribute 20% to liquid biofuel growth in the accelerated case by 2031. Brazil leads this expansion through the implementation of E35 blending under its Fuel of the Future Law, and the United States follows owing to permanent nationwide E15 sales, and investments in fuel station infrastructure. The United States leads renewable diesel expansion thanks to higher RFS fuel volume obligations and continued incentives under the 45Z Clean Fuel Production Tax Credit (PTC), and increases also occur in Indonesia and Europe (under RED III). However, further expansion will likely require additional sustainable feedstock supplies as competition from biodiesel and SAF production intensifies.

Biodiesel growth stems from higher blending mandates in Indonesia, as it makes progress towards its B50 target, Malaysia and India, as well as Brazil implementing its B20 target under the Fuel of the Future Law. Achieving these targets will again likely require additional feedstock supplies, and production capacity, while further growth in India remains constrained by long-standing feedstock availability and distribution challenges.

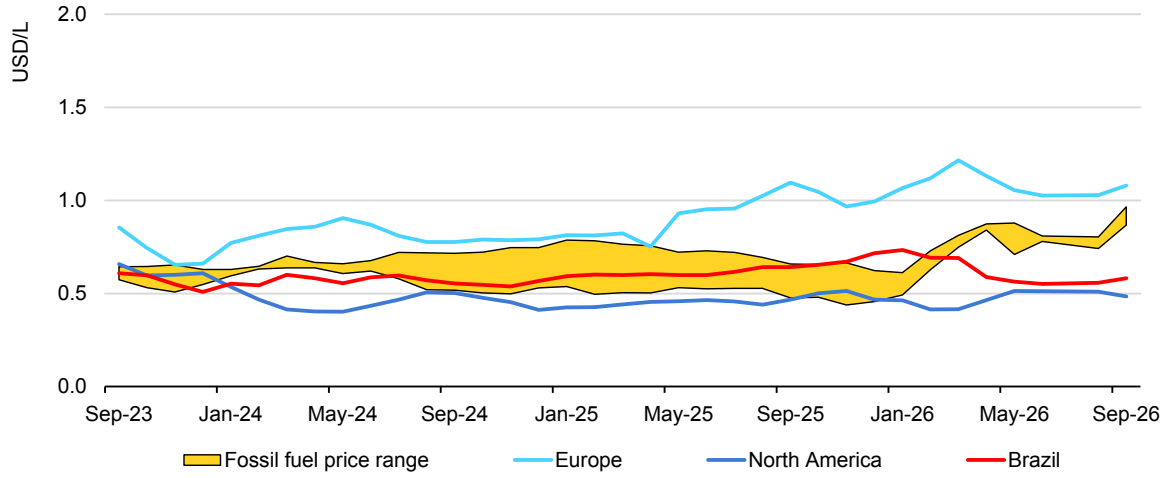
Prices

Ethanol prices have remained relatively competitive, ranging within 10% of gasoline prices over the last three years. However, regional differences exist. In the United States and Brazil, ethanol prices have generally remained at or below gasoline prices owing to long-standing policy frameworks that promote both production and consumption. Federal policies in the United States (the RFS and

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the 45Z Clean Fuels PTC) and several state-level performance-based standards continue to support ethanol markets. In Brazil, the established ethanol industry benefits from decades of policy support, mandates, performance-based fuel standards and government-backed financing to reduce exposure to international feedstock and fuel price volatility. In contrast, ethanol prices in Europe have generally remained above gasoline prices. Greater reliance on imports, combined with increasing demand under RED III, has tightened market conditions and placed upward pressure on prices.

Gasoline and ethanol prices by selected market, September 2023-September 2026



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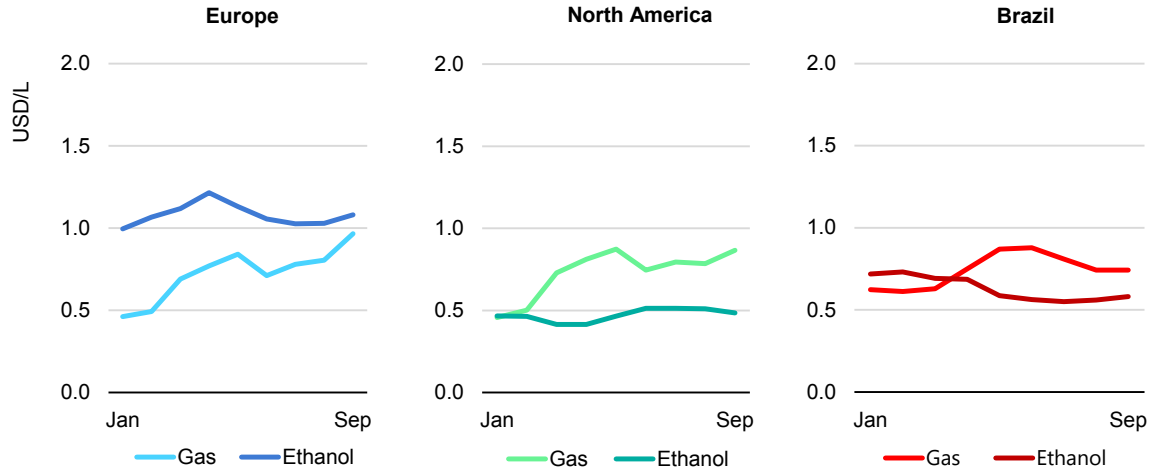
Note: Prices are based on combined averages of free-on-board regional indices.
Source: IEA analysis based on from Argus Media group. All rights reserved (full disclaimer on copyright page).

More recently, gasoline price increases stemming from the current conflict in the Middle East have improved ethanol's competitiveness in most markets. In the United States and Brazil, strong domestic production and supportive policy frameworks have kept ethanol prices at or below gasoline prices. In Europe, ethanol prices have remained higher, but the sharp rise in gasoline prices has narrowed the price gap. However, this competitiveness gain may prove temporary if oil market conditions ease.

Unlike ethanol, biodiesel and renewable diesel prices have remained two to three times higher than diesel on average. In Europe, reliance on imported feedstocks from Asia and growing competition among biodiesel, renewable diesel and SAF producers for the same feedstocks have kept prices elevated. Biodiesel costs are also high because of the EU Fuel Quality Directive's blending limits, which constrain market growth and limit achievement of economies of scale. By contrast, fewer blending constraints apply to renewable diesel, and it can be used as a drop-in fuel, allowing producers to capture a price premium and compete more aggressively for feedstocks, further increasing costs across both fuel markets.

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Gasoline and ethanol prices by selected market, January 2026-September 2026



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Note: Prices are based on combined averages of free-on-board regional indices.
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In North America, renewable diesel has remained more cost-competitive than biodiesel owing to its drop-in compatibility and stronger policy incentives. Federal and state fuel standards in the United States provide additional credit-generating opportunities, improving project economics relative to biodiesel. Recent changes to federal PTCs have also begun to intensify feedstock competition by favouring fuels produced from North American feedstocks. As renewable diesel producers can often pay more for feedstocks, they have generally been better positioned to secure supplies.

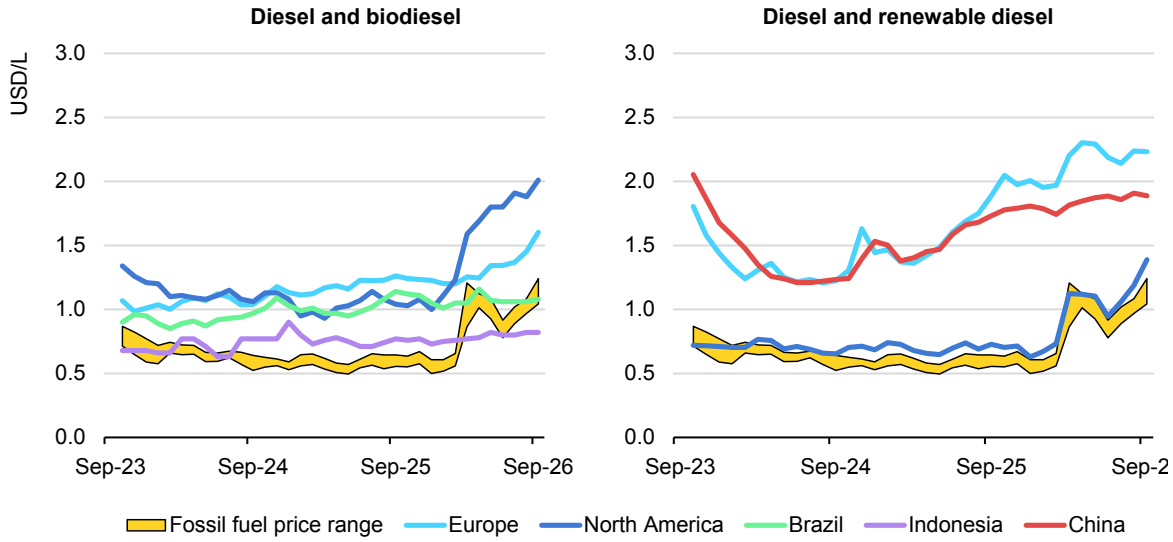
In South America, mainly in Brazil, biodiesel prices have remained elevated because the cost of soybean oil – the main feedstock – is linked to broader agricultural markets, and both domestic blending requirements and export markets create demand competition. In Asia Pacific, biodiesel prices remain comparatively lower, due to greater feedstock availability and domestic pricing mechanisms (particularly in Indonesia) that favour locally produced biodiesel over imported diesel. Renewable diesel prices have remained high, particularly for Chinese supplies, as export growth has allowed producers to put a price premium on their product even though domestic consumption is declining due to greater electrification of transport in the domestic market. Rising demand for the same feedstocks to produce marine biodiesel and SAFs, largely targeting international markets, is likely to maintain upward pressure on prices.

More recently, the current conflict in the Middle East raised diesel prices globally, narrowing the price gap between fossil diesel and renewable alternatives in most markets. In Europe, prices for biodiesel and renewable diesel experienced slightly less volatility than their fossil fuel counterpart. Biodiesel prices increased more

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gradually through consistent demand under blending mandates, while renewable diesel prices rose more quickly due to stronger competition for it under RED III as a drop-in ready fuel and lower imports from the United States. However, despite the rapid increase in diesel prices, the price gap between biodiesel and renewable diesel with conventional diesel remains.

Diesel, biodiesel and renewable diesel by selected markets, September 2023-September 2026



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Note: Prices are based on combined averages of free-on-board regional indices.

Sources: IEA analysis based on from Argus Media group. All rights reserved (full disclaimer on copyright page); Brazil National Agency of Petroleum (2026), Natural Gas and Biofuels (ANP) database, (accessed 21 September 2026); Indonesia Ministry of Energy and Mineral Resources (2026), Directorate General of New, Renewable Energy and Energy Conservation (EBTKE-ESDM) database, (accessed 21 September 2026).

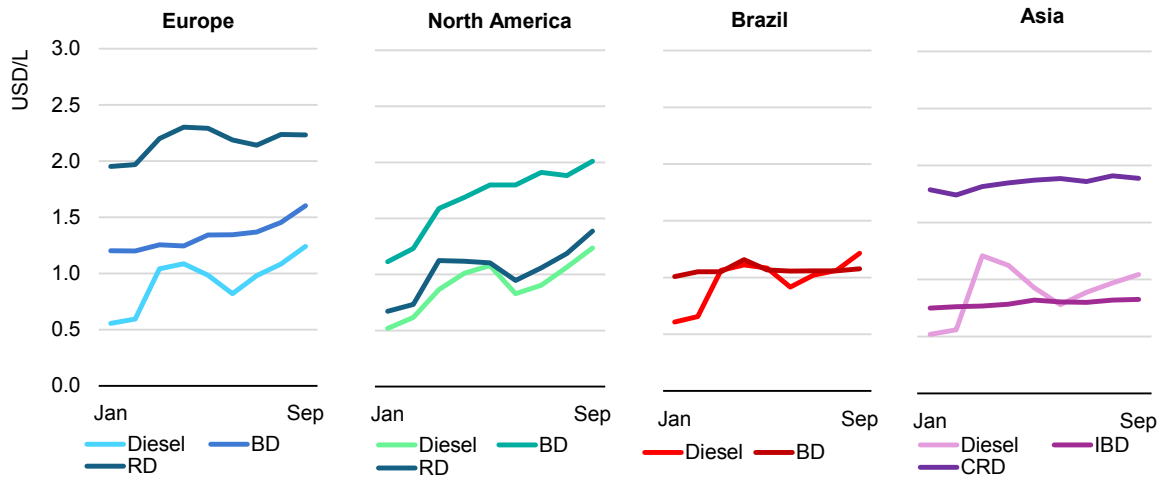
In North America, biodiesel prices rose sharply due to policy changes. Amendments to feedstock eligibility under the US 45Z Clean Fuel PTC, increasing competition for North American feedstocks, higher biodiesel and renewable diesel obligations under the US RFS, and more limited production capacity compared with renewable diesel, contributed to tighter market conditions. Meanwhile, renewable diesel prices have remained comparatively lower (closer to elevated diesel prices) owing to larger production capacity and stronger feedstock purchasing power.

In South America, led by Brazil, biodiesel prices stayed relatively stable even as diesel prices doubled, narrowing the price gap between the two fuels. Similarly, biodiesel and renewable diesel prices remained unchanged in Asia Pacific despite diesel prices doubling. Long-term policy support and monthly demand-side domestic pricing mechanisms designed to incentivise consumer choice,

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particularly in Indonesia, helped keep biodiesel competitive. Meanwhile, renewable diesel prices in China remained elevated but stable as Chinese producers increasingly targeted export markets.

Diesel, biodiesel and renewable diesel prices by selected market, January 2026-September 2026



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Notes: BD = biodiesel. RD = renewable diesel. IBD = Indonesian biodiesel. CRD = Chinese renewable diesel. Prices are based on combined averages of free-on-board regional indices.

Sources: IEA analysis based on from Argus Media group. All rights reserved (full disclaimer on copyright page); Brazil National Agency of Petroleum (2026), Natural Gas and Biofuels (ANP) database, (accessed 21 September 2026); Indonesia, Ministry of Energy and Mineral Resources (2026), Directorate General of New, Renewable Energy and Energy Conservation (EBTKE-ESDM) database, (accessed 21 September 2026).

Trends to watch

Electrification of road transport accelerates despite supply chain concentration

EV uptake is accelerating not only to reduce emissions but to curb dependence on imported fossil fuels and exposure to price volatility from natural disasters and geopolitical disruption. Advances in battery technology are also encouraging adoption.

In 2025, more than 100 countries recorded electric car sales, and global purchases of electric cars grew 20%, making up one-quarter of all new car sales. Similarly, with electric trucks slowly becoming more cost-competitive, purchases doubled in 2025 to make up just under 10% of all new truck sales. Strong demand-side incentives, paired with more readily available affordable EVs and continued support for charging station infrastructure, underpin this growth.

However, supply chains are still geographically concentrated and are expected to remain so. In 2025 China manufactured nearly 75% of the world's electric vehicles

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and over 80% of battery cells. Consequently, electric cars from China made up 55% of electric car sales in countries outside of Europe or the United States. Interest is therefore growing in other parts of Asia, as well as in Europe and North America, to enlarge EV manufacturing, especially as countries continue to negotiate partnerships as well as bilateral and multilateral critical-mineral trade deals. For instance, Australia and India have developed a Critical Minerals Investment Partnership, while Canada, the United States, Japan, Germany, France, the United Kingdom, Italy, Australia and the European Union have formed a Critical Minerals Resilience and Production Alliance to mobilise capital, accelerate critical-mineral project development and develop supply chains.

Although supply chains are projected to remain strongly concentrated in the short and potentially medium term, EV demand is expected to continue to grow as countries accelerate deployment. Global electric car purchases alone are anticipated to make up 29% of total car sales by the end of 2026 while the global fleet of EVs is projected to grow more than sixfold by 2035 from 2025 level as these vehicles become increasingly affordable and accessible.

Fuel security concerns renew interest in flex-fuel vehicles

Like EVs, flex-fuel vehicles (FFVs) can support energy security and emissions reduction targets. Although their fuel economy may be lower than for engines optimised for a narrower range of fuel properties, FFVs can operate on ethanol blends of up to E100, reducing gasoline consumption.

FFVs are already well established in some markets. In Brazil, consumers have been adopting FFVs over the last two decades because ethanol prices have become more cost-competitive due to tax reductions, vehicle incentives and the development of ethanol supply chains to support large-scale use of ethanol and high-ethanol blended gasoline. More recently, Brazil launched the Carro Sustentável (Sustainable Car) initiative under its broader green-mobility MOVER programme. The policy offers tax exemptions for qualifying Brazilian-manufactured compact vehicles that meet its energy efficiency, environmental performance and recyclability criteria. Given the dominance of flex-fuel technology in Brazil's light-duty vehicle market, many ethanol-compatible vehicles are expected to benefit from the scheme.

Similarly, in the United States, support for ethanol supply chains, federal and state procurement policies for FFVs, and fuel-economy compliance credits under the Corporate Average Fuel Economy (CAFE) programme have encouraged the production and purchase of E85 vehicles over the last two decades.

More recently, FFVs have also been gaining attention in other markets, particularly in the Asia Pacific region, due to the impact of the current conflict in the Middle East on gasoline prices. For example, India has announced a Production-Linked

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Incentive to support the manufacture of flex-fuel vehicles and ethanol-compatible engine components, helping expand ethanol use in road transport and reducing crude oil imports for gasoline production. Hero Motocorp launched is first-ever flex-fuel motorcycle recently, and several automakers (e.g. Suzuki, Toyota and Hyundai) have also announced plans to launch FFVs in India that can run on E85 to E100 fuel. Meanwhile, as part of Japan's Sustainable Fuel Policy, the government intends to develop fuel standards for E10 and E20 blended gasoline along with potential supply- and demand-side policy measures.

Marine

Key points

- Marine biodiesel demand more than doubles to nearly 2 billion litres per year, to make up 0.6% of total marine fuel consumption by 2031, but accounts for only 1% of renewable energy growth in transport.
- Europe accounts for 80% of marine biodiesel growth, driven by FuelEU Maritime regulations to cut well-to-wake GHG intensity.
- In the accelerated case, demand rises to more than 12 billion litres per year, making up 4% of total marine fuel consumption by 2031, assuming the IMO Net-Zero Framework is adopted.

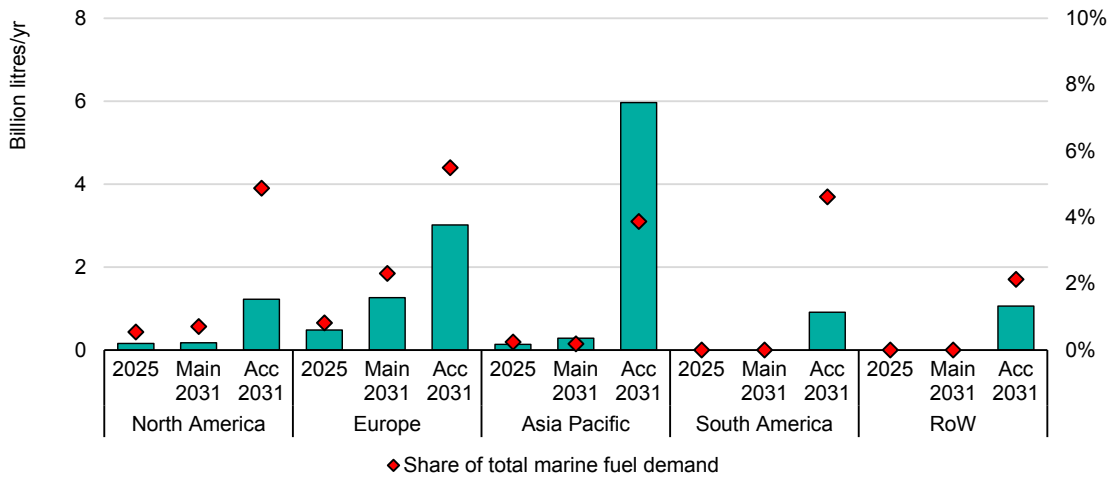
Forecast

Marine biodiesel remains the leading source of renewable energy in maritime transport. Demand is forecast to more than double from just under 1 billion litres per year (14 kb/d) in 2025 to nearly 2 billion litres per year in 2031 (30 kb/d), equivalent to 0.6% of total marine fuel use, and accounts for 1% of renewable energy growth in transport. Europe drives four-fifths of this growth, with the FuelEU Maritime requirements to reduce ships' well-to-wake GHG intensity 6% by 2030 and 14.5% by 2035. Marine biodiesel is expected to deliver much of the near-term reduction while alternative fuel use and energy efficiency measures are scaled up. Most of the remaining increase occurs in Singapore and China, where ports supply vessels serving the European market. Growth elsewhere remains limited due to weak policy support and demand signals.

The accelerated case assumes eventual adoption of the IMO Net-Zero Framework during the forecast period, creating long-term global demand for low-emissions marine fuels. As a result, marine biodiesel use rises to more than 12 billion litres per year (210 kb/d) to make up 4% of total marine fuel demand by 2031.

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Marine biodiesel demand in marine transport, main and accelerated cases, 2025 and 2031



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Notes: Acc = accelerated case. RoW = rest of world. Shares reflect marine biodiesel in total marine fuel demand.
Source: IEA (forthcoming), World Energy Outlook 2026.

The IMO Net-Zero Framework would cover roughly 97% of the world's merchant shipping fleet by tonnage and introduce a two-tiered GHG Fuel Intensity (GFI) reduction framework. By 2030 ships missing the base target of 8% would pay USD 380/t CO_2-eq, while those missing the compliance target of 21% would pay USD 100/t CO_2-eq.[10] Most ships would likely meet the initial 8% reduction by blending lower-emissions fuels or purchasing credits, as liquified natural gas (LNG), marine biodiesel and biomethane are among the less-expensive commercially available options.

Achieving the deeper 21% threshold would be more difficult, given the limited availability and higher cost of fuels such as bio-methanol, e-methanol and ammonia, and the lower penalty for non-compliance. As marine biodiesel is one of the few commercial options available, the accelerated case assumes that it provides enough additional supply for most ships to reach the 8% threshold but not the full 21% reduction, with competing road transport demand potentially limiting marine biodiesel supplies.

Prices

Marine biodiesel prices have remained around twice as high compared to very-low-sulphur fuel oil (VLSFO) over the last three years. Limited policy incentives to expand supply and demand beyond the EU's FuelEU Maritime regulations,

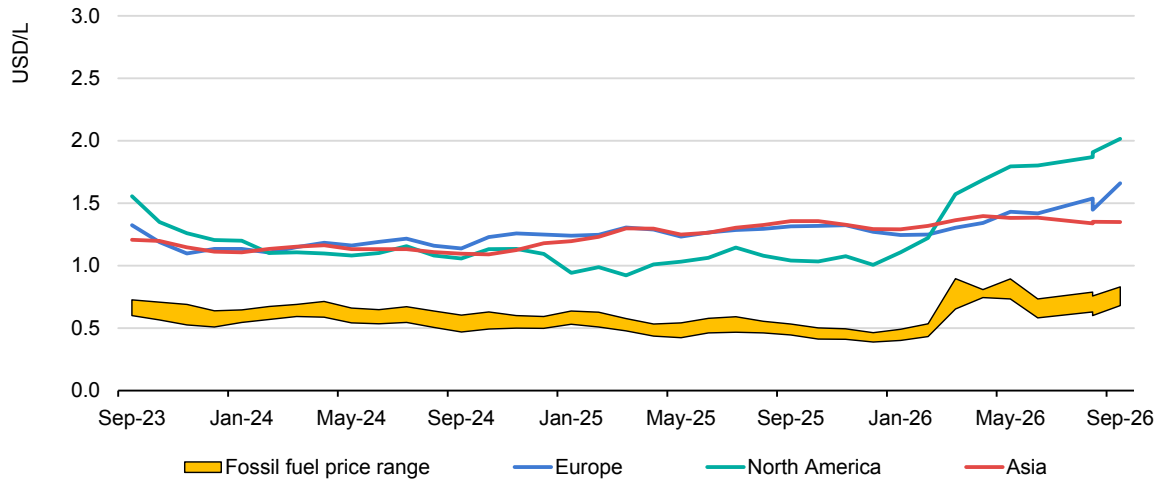
[10] While targets for GFI are set beyond 2030, the draft MARPOL ANNEX VI regulations do not set prices beyond this year and notes that setting prices beyond 2031 would be subject to review by January 2028.

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together with competition for feedstocks to produce biodiesel and renewable diesel for road transport, and biojet fuel for aviation, have sustained this price premium.

In North America, marine biodiesel prices have been slightly lower than in other markets as some policies indirectly support production and reduce costs – mainly the US 45Z Clean Fuel PTC, which provides upwards of roughly USD 0.25/litre (USD 1.00/gallon) for renewable fuels, including biodiesel that can be blended into marine transport fuel. However, recent increases to RFS fuel obligations (which will further raise biodiesel and renewable diesel demand), in addition to feedstock eligibility changes for the 45Z Clean Fuel PTC and higher tariffs on imported waste oils and fats, have raised prices. Further increases in feedstock competition and cost could cause prices to remain high.

Marine fuel oil and biodiesel prices by selected markets, September 2023-September 2026



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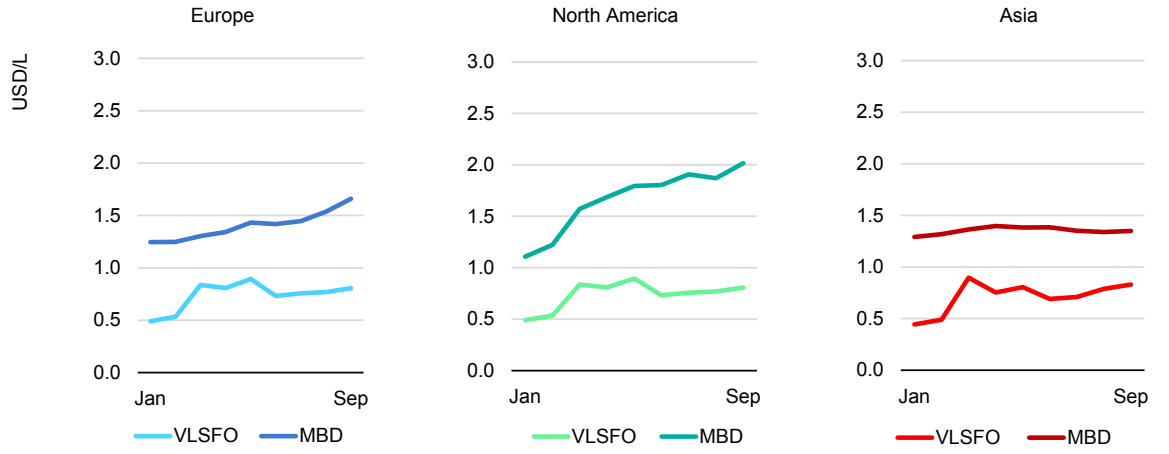
Note: Prices are wholesale free-on-board prices before taxes and delivery fees.
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In Europe, prices for marine biodiesel have remained elevated despite strong policy support, including from FuelEU Maritime and the EU Emissions Trading System, which improve the competitiveness of low-emission fuels. However, the region remains highly dependent on imported feedstocks (mainly from Asia Pacific) to meet European sustainability requirements, while demand for these feedstocks also continues to grow for biodiesel, renewable diesel and SAF production. As a result, feedstock competition is expected to keep prices high and limit opportunities for cost reductions. Over the longer term, the scale-up of other sustainable fuels, including biomethane, e-methanol and ammonia, could ease pressure on biodiesel demand and lead to price declines.

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Similarly, marine biodiesel prices in Asia have remained strong as growing European demand continues to draw feedstocks and fuel supplies into export markets. Competition for waste oils and fats to produce biodiesel, renewable diesel and SAF has further tightened regional feedstock markets, limiting cost reductions. While additional demand is expected to keep prices elevated in the near term, the emergence of alternative marine fuels could moderate future biodiesel demand and reduce prices.

Regional marine fuel oil and biodiesel prices by selected markets, January 2026-September 2026



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Notes: VLSFO = very-low-sulphur fuel oil. MBD = marine biodiesel. Prices are wholesale free-on-board prices before taxes and delivery fees.

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The current conflict in the Middle East pushed fossil fuel prices higher between January and September 2026, with marine fuel nearly doubling in some markets. Although the price premium for marine biodiesel persisted as disruptions to shipping routes reduced feedstock availability and increased costs, this cost advantage could narrow as additional regulatory measures take effect and the use and production of alternative low-emissions fuels (biomethane, ethanol, e-methanol and ammonia) scales up. In the short to medium term, however, stronger policy support and measures to expand sustainable feedstock supplies will be needed to reduce costs in an increasingly competitive global market.

Trends to watch

Shipping is looking to other sustainable fuels to meet environmental and economic objectives

While marine biodiesel remains the most commercially available low-emissions fuel, demand for a suite of sustainable liquid fuels, such as liquified biomethane,

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ethanol, renewable hydrogen and renewable hydrogen-based fuels, is growing to reduce emissions in the sector as well as dependence on concentrated fossil fuel supply chains.

For example, liquefied biomethane can be used as a drop-in fuel to replace LNG, avoiding significant on-board (or bunkering) retrofits while providing immediate emissions reductions. With LNG bunkering available at more than 200 ports globally, existing infrastructure could support greater liquefied biomethane uptake where sustainable supplies are available.

Similarly, interest in ethanol, traditionally blended with gasoline for road transport, is also growing because several regions of the world have well-established supply chains. In 2025, Maersk (one of the world's largest shipping companies) began test trialling ethanol in the Laura Maersk container ship. The first trial in late 2025 tested an E10 blend with methanol, eventually leading to an E50 test trial and an E100 test trial in 2026, all with positive results.

Several other large shipping companies have also begun testing ethanol in their ships. In 2026, CMA GGM completed its first ethanol test trial in Brazil, while X-Press Feeders trialled an E10 blend in the Netherlands at the Port of Rotterdam. However, ethanol use in marine transport would likely require updates to fuel regulations and investment in port storage, handling and distribution infrastructure, supported by demand strong enough to justify these upgrades.

Other sustainable fuels, including hydrogen and hydrogen-derived fuels such as e-methanol and ammonia, are also attracting interest despite their limited commercial availability. Expanding renewable electricity capacity worldwide is improving the prospects for producing these low-emissions fuels at scale and across a wider range of regions. In 2025, cumulative offtake agreements for hydrogen-based fuels in marine transport amounted to over 800 ktpa H_2-eq (an increase of 7% from 2024), and in August 2026 there were nearly 300 methanol- and 40 ammonia-fuelled ships on order for 2030. However, accompanying storage and handling infrastructure will need to be built, and strong health and safety regulations will need to be developed for handling some of these fuels (e.g. ammonia).

Dual-fuel engines unlock fuel flexibility in the shipping sector's energy transition

Dual-fuel engines can run on a range of conventional and low-emission liquid fuels, including marine fuel oils, LNG, marine biodiesel, liquified biomethane, ethanol, hydrogen and hydrogen-based fuels. They give shipowners flexibility to meet route-specific regulations while adapting to fuel availability and price conditions. As sustainable fuel production and infrastructure scale up, this

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flexibility can also support green shipping corridors by giving ports time to develop the bunkering infrastructure and safety standards needed to handle new fuels.

Since 2021, new orders for dual-fuel container ships and vehicle carriers have increased more than twelve-fold, from less than 60 ships on order in 2021 to more than 750 as of March 2026, as the industry seeks greater flexibility and versatility as the sector evolves. Leading marine engine manufacturers such as Wartsila have been increasingly producing these engines for cargo ships and ferries, while the foremost cargo transport companies, such as Maersk, have been quickly integrating these ships into their fleets. In addition, many existing ships can be retrofitted with these engines depending on the size and age of the vessel.

Energy efficiency gains cut fuel use and emissions while easing demand for sustainable fuels

While sustainable fuels will be needed to curb emissions in marine transport, energy efficiency improvements can also lower fuel consumption and reduce the total volume of low-emissions fuel required to meet regulatory targets. Indeed, some measures are already widely used: in the past 15 years, lower speeds and larger vessel size have made it easier to cut fuel costs and comply with evolving regulations. Travelling at lower speeds can significantly reduce fuel use, while using larger vessels to carry more cargo relative to hull surface area improves efficiency.

However, a suite of other commercially available technologies exists. Operational measures – e.g. optimising cargo-handling at ports; keeping the hull clean; changing shipping routes based on weather patterns; and improving access to renewable electricity so that ships do not need to burn fuel while at port – can provide energy efficiency gains of 3-50%. Meanwhile, mechanical and design details – such as hull, propeller and rudder design; hull paints and coatings; integration of batteries and hybrid fuel systems; and the addition of sails – can improve efficiency 2-40%.

Interest in these technologies is growing among port authorities and ship owners alike. For example, the ports of Singapore and Rotterdam have implemented the Just-In-Time (JIT) Planning and Coordination Platform to improve arrival and departure scheduling, reduce wait times for harbour services such as harbour pilots, and streamline port services such as cargo handling between ships. More recently, the Port of Rotterdam also implemented geofencing systems to more accurately track and predict ship arrivals.

Shipping companies have also begun to implement further energy efficiency measures to meet regulatory requirements and reduce fuel costs. For example, Mitsubishi Corporation's Pyxis Ocean was one of the first vessels to be retrofitted with Cargill and Bar Technologies' WindWings, a set of commercial shipping-scale

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sails to leverage wind power and reduce overall fuel consumption. Meanwhile, Neoline has developed the first industrial-scale wind-powered cargo vessel, with monthly service between Europe and North America.

Aviation

Key points

- Biojet fuel demand grows nearly fivefold to 10 billion litres per year by 2031, making up 2% of aviation fuel consumption and accounting for 9% of renewable energy growth in transport.
- The United Kingdom and the European Union lead growth, spurred by mandates, followed by North America, where production incentives and low-carbon fuel standards, rather than federal mandates, drive growth.
- In the accelerated case, demand increases to nearly 22 billion litres per year to meet just over 4% of aviation fuel demand by 2031, as countries around the world make greater progress in achieving their SAF targets but require new technologies and faster project development to increase supply.

Forecast

Demand for Sustainable Aviation Fuel (SAF) – primarily for biojet fuel – is forecast to increase nearly fivefold from just over 2 billion litres a year (35 kb/d) in 2025 to 10 billion litres a year (172 kb/d) in 2031, making up 2% of total fuel demand in aviation transport and accounting for 9% of renewable energy growth in transport.

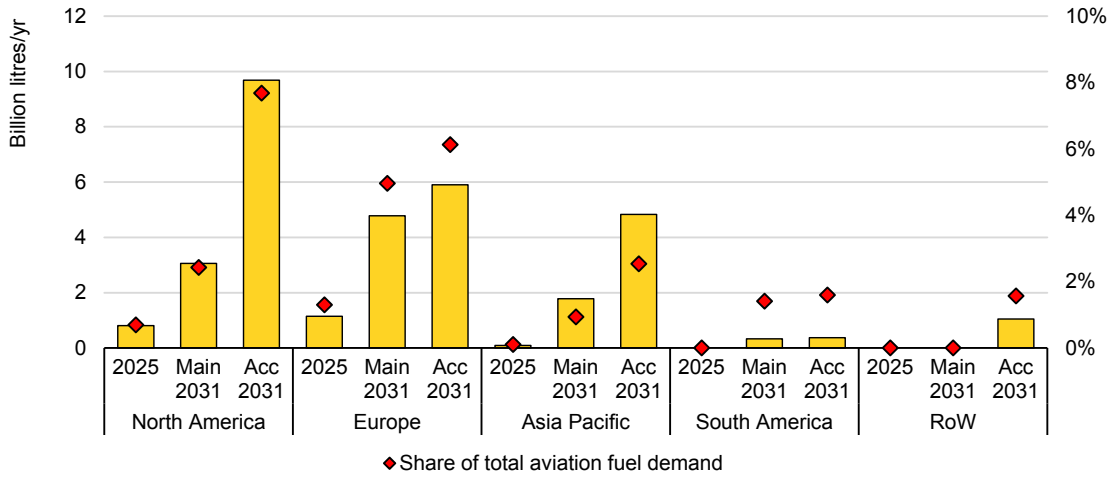
Of this increase, 45% happens in Europe, driven by implementation of the UK SAF mandate and the EU ReFuelEU Aviation regulation. While both frameworks include rising sub-targets for e-SAF, biojet fuel is expected to meet most demand over the forecast period. Restrictions on food crop-based feedstocks in the European Union could challenge supply availability, and/or prohibit imports of biojet fuel made from these feedstocks in other regions, increasing the need for alternative feedstocks (e.g. forest residues and organic municipal waste) and faster deployment of emerging pathways, such as the alcohol-to-jet (ATJ) and Fischer-Tropsch processes, and the production of hydrogen-based fuels, including e-SAF.

North America, led by the United States, accounts for another roughly 30% of expected growth. Demand continues to rise despite reduced federal support under the 2025 One Big Beautiful Bill Act (OBBBA), which removed the federal SAF blender tax credit and lowered the maximum 45Z Clean Fuel PTC from

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USD 1.75/gallon to USD 1.00/gallon. As a result, remaining US federal and state tax credits now support expansion, together with California's and Oregon's low-carbon fuel standards, and the Canadian province of British Columbia's blending requirement of 3% by 2030 under its provincial low-carbon fuel standard. Investment is also increasing in projects using technologies that can take advantage of a wider range of feedstocks.

Biojet fuel demand by region, main and accelerated cases, 2025 and 2031



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Notes: Acc = accelerated case. RoW = rest of world.

The Asia Pacific region makes up an additional 20%. SAF mandates, supply-side obligations, and indicative and emissions-reduction based are expected to establish early demand ranging from 1% in the near term to 3-10% by 2030-35 in India, Singapore, Japan Korea and Indonesia, meanwhile Malaysia has also announced more ambitious longer-term targets. Competition for the feedstocks required to produce biojet fuel is likely to intensify, particularly in countries such as Indonesia that also plan to expand biodiesel and renewable diesel production for road transport. In addition, while China has no long-term mandate, it recently released its Green Fuel Development Report to support development of sustainable fuels, including biojet fuel, to reduce emissions and improve energy security. It is also continuing to expand SAF production capacity as demand in both the region and elsewhere (primarily Europe) continues to grow with the implementation of mandates.

Remaining growth comes from Brazil under its Fuel of the Future Law, which requires airline operators to reduce GHG emissions 1% by 2027 and 10% by 2037. While this is not a SAF mandate, it is expected that biojet fuel will be used to achieve most of these emissions reductions, with initial biojet fuel deliveries to Rio de Janeiro International Airport beginning last year from Petrobras.

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In the accelerated case, demand for biojet fuel doubles from the main case, increasing to nearly 22 billion litres per year (376 kb/d) by 2031 – just over 4% of total aviation fuel demand. North America makes up 45% of this growth, supported by supply-side incentives, performance-based policies and investment in emerging production pathways that can use abundant feedstocks. However, stronger long-term demand signals would still be needed to reduce investment uncertainty, mobilise underused feedstocks and accelerate project development.

Asia Pacific and Europe each make up an additional 25% of this growth. Meeting the Asia Pacific region's SAF mandates will likely require additional sustainable feedstock supplies, as waste oils and fats used to produce biojet fuel from hydroprocessed esters and fatty acids (HEFA)[11] are also in demand for biodiesel and renewable diesel production. Thus, faster deployment of alternative production pathway, capable of using a broader range of feedstocks, will also be needed. In Europe, progress in meeting UK and EU SAF mandates accelerates, although substantial additional production capacity will be needed to meet demand.

Prices

Biojet fuel prices have remained around 2.5 times higher than for conventional jet kerosene over the last three years. In North America, federal and state incentives have improved competitiveness by supporting production and creating additional revenue streams through low-carbon fuel standards and renewable fuel obligations. As a result, the business case for biojet fuel has strengthened despite its higher production costs. However, this advantage could narrow as changes to the 45Z Clean Fuel PTC restrict eligibility to producers using North American feedstocks, while higher tariffs on imported waste oils and fats increase costs for producers relying on global supply chains.

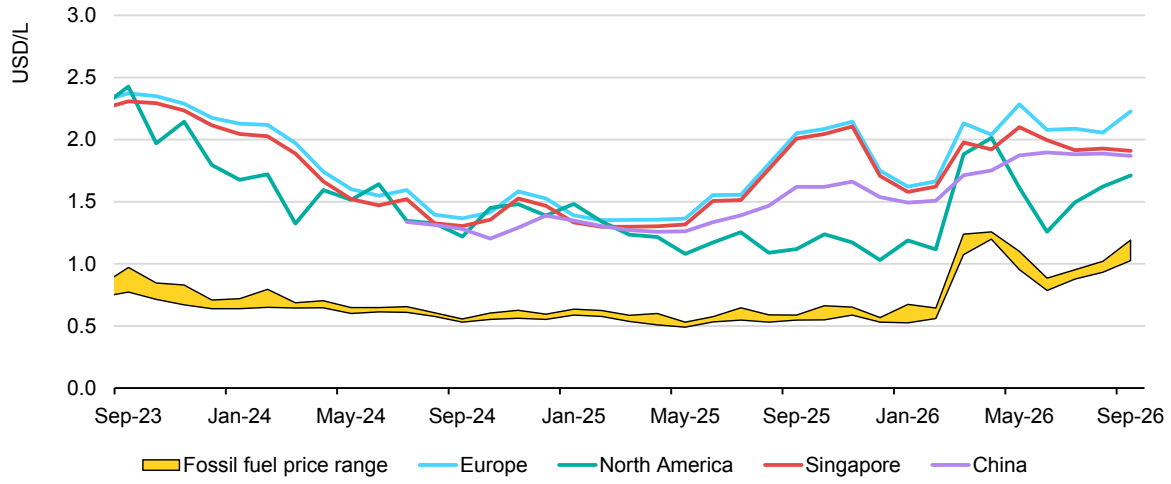
Outside of North America, biojet fuel prices have remained higher due to greater exposure to feedstock costs and more limited production incentives. In Europe, reliance on imported waste oils and fats, combined with strong demand from biodiesel and renewable diesel producers, has tightened feedstock markets and kept production costs elevated. At the same time, these feedstocks are also in high demand for biodiesel and renewable diesel production, creating additional supply pressure and limiting cost reductions. Restrictions on feedstock eligibility under ReFuelEU Aviation further limit flexibility compared with North America, where producers can access a broader range of feedstocks. European biojet fuel

[11] SAF produced through the HEFA process uses a technique known as hydrotreatment, wherein feedstocks such as vegetable oils and waste oils and fats react with hydrogen at high temperatures and are then hydrocracked. The long hydrocarbon chains are broken to create SAF. HEFA fuel is currently certified to be blended up to 50% with conventional jet kerosene and is also the most commercially available pathway for SAF production.

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prices could therefore become more volatile as competition for imported feedstocks intensifies and Asia Pacific producers increasingly prioritise domestic SAF markets.

Jet and biojet fuel prices by selected market, September 2023-September 2026



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Note: Prices are wholesale free-on-board prices before taxes and delivery fees.
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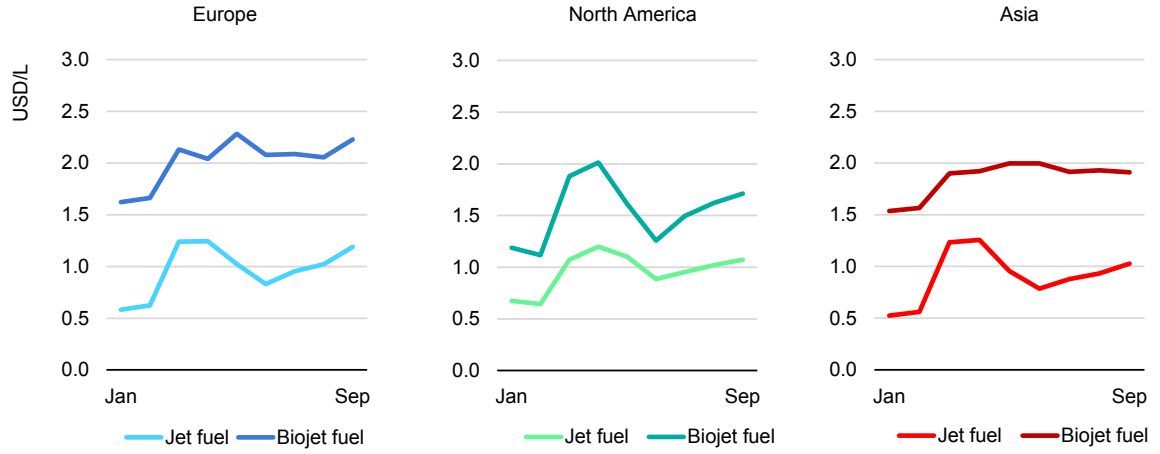
Biojet fuel prices have also remained elevated in Asia Pacific, despite greater regional availability of waste oils and fats. Strong demand from European SAF producers has continued to keep feedstock prices strong, while China's restrictions on waste oil and fat exports have further tightened the market. Looking ahead, prices could remain high as SAF mandates expand across the region, demand from biodiesel and renewable diesel producers grows, and domestic feedstocks are used increasingly for biojet fuel production.

More recently, the current conflict in the Middle East triggered a sharp jump in jet fuel prices, with kerosene more than doubling in some markets. However, biojet fuel's long-standing price premium persisted as disruptions to shipping routes reduced feedstock availability and raised supply costs, while limited production capacity constrained supply growth.

At the same time, rising demand for waste oils and fats to produce biodiesel, renewable diesel and marine biodiesel intensified competition for feedstocks. As a result, reducing biojet fuel costs will require stronger policy support to expand supplies, including measures to ensure sustainable feedstock availability and to develop and commercialise new technologies to access non-traditional feedstocks in an increasingly competitive global market.

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Jet and biojet fuel prices by selected market, January 2026-September 2026



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Notes: Prices are based on the combined averages of regional and country indices for HEFA-SPK in the case of biojet fuel. Prices are wholesale free-on-board prices, before taxes and delivery fees.

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Trends to watch

New fuel technologies could enable the use of non-traditional feedstocks to unlock further SAF supply expansion

Driven by demand for biodiesel, renewable diesel and HEFA-SAF production, competition for vegetable oils, and waste oils and fats, is raising interest in alternative production pathways for biojet fuel. Technologies such as the alcohol-to-jet (ATJ) method, which uses alcohol intermediates such as ethanol to produce biojet fuel, and the Fischer-Tropsch (FT) process, which converts synthesis gas from gasified biomass such as agricultural residues and forest product manufacturing residues into a liquid, are attracting attention because they can produce biojet fuel from a broader array of feedstocks, most which often cost less and are more abundant.

The biojet fuel produced from these technologies remains two to five times more expensive than conventional jet kerosene, but it is still more cost-competitive than some other emerging production pathways. Despite the cost premium, several factors are strengthening demand signals for new production techniques: SAF mandates; the ability to use SAF as one of several ways to meet CORSIA emission reductions requirements; and the potential to use lower-cost feedstocks. As a result, investment in ATJ and FT projects is increasing globally, from front-end engineering design (FEED) studies, to pilot and demonstration plants, to final investment decisions.

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In North America, Lanzajet opened its Freedom Pines Fuels ATJ facility in the United States in 2025, following an investment of more than USD 300 million. It can produce over 37 million litres per year. Gevo is also planning to invest USD 600 million in an ATJ project paired with carbon capture and storage technology, capable of producing more than 200 million litres per year from ethanol.

In Europe, Lanzajet has partnered with SkyNRG to develop an ATJ project and has announced a FEED study in the United Kingdom for a facility that can produce 90 million litres per year. Meanwhile, Altalto is currently finalising its pre-FEED study on an FT facility that would produce over 60 million litres per year from municipal solid waste.

Interest is also growing in South America and some parts of Asia Pacific given their strong ethanol supply chains and feedstock availability. In Brazil (a world leader in ethanol production), Petrobras has announced investments in two facilities capable of producing more than 800 million litres per year by 2029, while JetBio plans to invest USD 2 billion in a 1 billion-litre-per-year ATJ facility. In India, Praj Industries has successfully completed a demonstration-level ATJ project using Axens Jetanol technology, while in Japan, Toyo has developed a demonstration-level FT facility using low-value wood residues, and SAFasia is looking to develop an FT project capable of producing roughly 30 million litres per year in the Philippines.

Energy efficiency measures amplify SAF impacts

SAF is expected to play a central role in the aviation sector's energy transition, but energy efficiency measures remain important for continued fuel consumption and emissions reductions. Improvements in aircraft and engine design, in aerodynamics and lightweighting of materials, and in software and electrical systems can all reduce energy consumption as SAF use scales up.

Historically, each new generation of aircraft has delivered a roughly 20% reduction in energy use compared with previous models. Further gains are expected as aircraft and engine manufacturers continue to improve design, fabrication methods, materials and digital systems. For example, longer and thinner wings can reduce drag, and Boeing's new 777X increased wingspan is expected to improve energy efficiency by 10%. Changes in materials, for instance using more lightweight composites, can also reduce the overall weight of an airplane, while further automation and software improvements can decrease on-board electricity demand.

Beyond these measures, airplane manufacturers have been considering more fundamental aircraft design changes that may be necessary to unlock further energy efficiency improvements. For instance, blended wing-body aircraft, which

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integrate the wings into the aircraft body, are attracting interest as they have less drag, better lift during take-off and landing, and can use smaller engines. While these design measures can be expensive and are often subject to long regulatory approval processes, they could improve energy efficiency an additional 10-20%.Policy assumptions, main and accelerated cases.

Country/region or subsector	Forecast assumptions
United States	**Main case** Increases to the fuel obligations under the federal RFS announced in March 2026 are implemented, as are revisions to feedstock eligibility under OBBBA and some small increases in E15 distribution, prompted by EPA waivers in 2026. By 2031, ethanol blending reaches 11%, biodiesel declines to 2.7%, renewable diesel increases to 8.5% and biojet increases to nearly 3%. **Accelerated case** Fuel obligations continue to increase to the end of the decade under the federal RFS. Broader E15 distribution raises ethanol consumption as E15 waivers are implemented permanently nationwide, and gas retailers upgrade necessary storage and distribution infrastructure. Continued PTC support for low-carbon fuel production and greater deployment of new technologies by the end of the decade, specifically for biojet fuel, prompt further growth for all fuels. By 2031, ethanol blending increases to 13%, biodiesel grows to 4%, renewable diesel climbs to 9% and biojet reaches 8.5%.
Brazil	**Main case** The federal ethanol blending mandate increases from E30 to E32 in response to the impact of the current conflict in the Middle East on gasoline prices and the biodiesel mandate rises slowly from B15 to B16 as testing has been delayed. Emissions reduction targets in aviation are introduced in 2027 under the Fuel of the Future Law, met by biojet fuel use. By 2031, total ethanol blending, including hydrous ethanol, rises to 55%, biodiesel increases to 16% and biojet reaches 4%. **Accelerated case** All Fuel of the Future targets for 2030 are met, resulting in E35 blending for ethanol, B20 blending for biodiesel, 3% blending for renewable diesel and a 3% emissions reduction in aviation with biojet fuel use. By 2031, total ethanol blending, including hydrous ethanol, reaches 61.5%, biodiesel increases to 20%, renewable diesel expands to 3% and biojet rises to 4.0%.

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Country/region or subsector	Forecast assumptions
India	**Main case** With strong continued development of the ethanol supply chain, the national E20 blending mandate is maintained. Feedstock availability challenges hinder biodiesel scale-up, but biojet fuel production begins to progress towards its 5% SAF blending target by 2030 owing to recent investments in both HEFA and ATJ production facilities. By 2031, ethanol blending stays at 20%, biodiesel blending remains at 0.25% and biojet blending increases to 4%. **Accelerated case** National ethanol blending rates rise to 21% as India continues to implement blending-mandate increases to further reduce imports of crude oil for transport fuel, and the 5% biodiesel and indicative SAF targets are met by 2030. By 2031, ethanol reaches 21% blending, and biodiesel and biojet climb to 5%.
Indonesia	**Main case** Biodiesel blending remains at 40% due to production capacity limitations, despite announced increases to blending levels to reduce fossil fuel imports. Some small progress is made towards a 2027 E10 target, a 2028 10% renewable diesel blending target, and a 2030 2.5% SAF blending target, relying on some domestic production but also imports. By 2031, biodiesel blending remains at 40%, ethanol rises to 2.5%, renewable diesel is at 3.0%, and biojet reaches 0.5%. **Accelerated case** Biodiesel blending reaches 45%, still short of the B50 target, as additional production capacity would need to be developed even more quickly than in the main case, and ethanol and renewable diesel blending also fall short of announced targets. The 2030 SAF target is met as it remains relatively low, and international flights are expected to comply with CORSIA requirements in 2027. By 2031, biodiesel blending rises to 45%, ethanol climbs to 4%, renewable diesel increases to 7% and biojet reaches 4%.
Europe	**Main case** EU member countries with implementation plans meet the RED III targets. They collectively achieve their 2030 ReFuelEU aim of 6% SAF blending as production is scaled up, and the FuelEU Maritime emission reduction targets are met. • Germany's GHG intensity-reduction obligation for transport fuels rises from 10.6% in 2025 to 30% by 2031, and the advanced biofuel mandate expands from 2% in 2026 to 9% in 2040, resulting in renewable diesel blending of roughly 6%.

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Country/region or subsector	Forecast assumptions
Europe (continued)	• France shifts from a renewable energy content obligation in transport to a carbon intensity requirement as announced to achieve RED III transposition. It targets emission reductions of 10.6% in road transport and 5.8% in aviation by 2030, and volumetric renewable fuel content of 10.5% in gasoline and 11.4% in diesel. Ethanol blending remains at 16% and biojet increases to 4%. • The Netherlands also shifts from a renewable energy content obligation in transport to a carbon intensity requirement to achieve RED III transposition. It targets emission reductions of 27.5% for all land-based transport and 14.5% for inland shipping. Ethanol blending reaches nearly 10% and marine biodiesel increases to 10%. • Ireland's updated renewable transport fuel obligations are implemented, shifting from 25% in 2025 to 32% in 2026. Advanced biofuel obligations rise from 1.5% to 5% in 2026. Ethanol blending reaches 6.5% and renewable diesel climbs to nearly 14%. • Spain's GHG intensity-reduction obligation for road transport rises from 8% in 2027 to 19% by 2031, with advanced biofuel sub-targets rising from 4% in 2027 to 5.5% by 2030. Ethanol blending rises to 8%, biodiesel to 7.5% and renewable diesel to 5.5%. • Italy's transposition of RED III is implemented, targeting a 29% share of renewable energy in transport by 2030. It also includes an 8% advanced biofuels target, with a 1% sub-target for renewable fuels of non-biological origin by 2030. Renewable diesel blending expands to nearly 7% by 2031. • The United Kingdom reaches 9% ethanol blending by 2031 and implements its 10% SAF blending mandate by 2030. **Accelerated case** The EU bloc continues to meet RED III targets, and the expansion of new and emerging technologies through funding programmes such as Horizon Europe and the Sustainable Transport Investment Plan ensure that renewable energy supply is sufficient to meet demand.

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Country/region or subsector	Forecast assumptions
Other countries	**Main case** In North America, Canada continues to implement its federal Clean Fuel Regulations, alongside the Province of British Columbia's 3% SAF blending mandate by 2030. In South America, Colombia maintains its E10 mandate; Argentina's maintains 12% ethanol blending; and Paraguay increases its biodiesel blending mandate to B8-B10. In Asia Pacific, Malaysia implements its announced B15 mandate; Thailand advances towards its E20 target, reaching 16% blending by 2031; Viet Nam blends higher shares of ethanol with consumers only able to buy blended E5 or E10 gasoline; Japan makes progress in achieving its recently announced E10 mandates; Korea takes steps towards meeting its 3-5% blending target by 2030; and Singapore reaches its 3-5% SAF target by 2030. **Accelerated case** In North America, Canada further supports SAF development by advancing recommendations under its national SAF Blueprint. In South America, Colombia increases its ethanol blending to E12, and Argentina converts its E15 blending target from voluntary to mandatory. In Asia Pacific, Viet Nam and Japan both achieve E10 blends by expanding their domestic production capacity; Thailand realises its E20 target by 2030; and Korea reaches its SAF blending target but also enlarges its domestic production capacity. On the African continent, Egypt, Ghana, Kenya, Nigeria, Mozambique, South Africa, Uganda and Zambia all follow through on biofuel blending mandates of up to 10% for ethanol and 5% for biodiesel by 2030.
Marine transport	**Main case** The EU FuelEU Maritime regulations impose increasingly stringent emission reduction targets for ships, requiring well-to-wake GHG intensity cuts of 6% by 2030 and 14.5% by 2035. While ships' emissions can be reduced by several means, this regulation is expected to boost demand for marine biodiesel as one of few commercially available solutions to curtail emissions in the short to medium term. **Accelerated case** The FuelEU Maritime regulation remains in place, and the IMO implements its Net-Zero Framework by 2028, with ships meeting the 8% emissions reduction baseline to avoid payments of USD 380/t CO_2-eq.

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Country/region or subsector	Forecast assumptions
Aviation transport	**Main case** The EU ReFuelEU Aviation regulations (targeting 6% SAF blending by 2030 and an e-SAF sub-target of 0.7%) and the UK SAF mandate (targeting 10% blending by 2030) drive demand, but further supply increases are required. Financial incentives in the United States through the 45Z Clean Fuel PTC, and credit-generating opportunities under federal and state-level low-carbon fuel standards, also boost biojet fuel consumption. Meanwhile, SAF mandates of 1-10% for 2030-2035 in several Asian countries (e.g. Korea, Singapore, India, Indonesia, Malaysia and Japan) spur initial increases, but the region must expand its production capacity and resolve feedstock demand challenges stemming from competition for these feedstocks among producers of biodiesel and renewable diesel for road and marine transport. In Brazil, the aviation emission reduction target of 10% by 2037 is expected to be met primarily through biojet fuel, creating a small amount of initial demand for SAF in South America. **Accelerated case** In Europe, the United Kingdom accelerates action to meet its longer-term SAF blending target of 15% by 2035, and the European Union is on pace to achieve 20% blending by 2035, but additional supplies are needed. In the United States, federal and state-level PTCs and credit-generating opportunities under low-carbon fuels standards continue to support SAF expansion, as does greater deployment of new fuel production pathways to leverage non-traditional feedstocks. Meanwhile, several Asian countries meet SAF mandates by increasing their biojet fuel production capacity rapidly and deploying new technologies to use non-traditional feedstocks.

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Chapter 3. Renewable heat

Summary

- As renewable heat use expands, total emissions begin to fall. Heat accounts for around half of global final energy consumption. The share of modern renewables in heat demand increases from 15% in 2025 to 19% in 2031, and total heat-related CO_2 emissions fall roughly 4% over the outlook period as power sector decarbonisation lowers indirect emissions.
- Electrification becomes the main source of growth. Renewable electricity used for heat rises from 9.4 EJ to 14.6 EJ by 2031, providing around two-thirds of modern renewable heat growth. Together with heat pumps, electricity-based heat accounts for three-quarters of the increase.
- China and the European Union lead deployment. China delivers more than one-third of global growth, mainly through industrial electrification, while the European Union is the second-largest contributor thanks to buildings sector electrification and renewable district heating.
- Direct renewable heat remains important but loses momentum. Modern bioenergy, solar thermal and geothermal provide around 60% of renewable heat in 2025 but only one-quarter of growth to 2031. Modern bioenergy, mainly solid biomass, remains the largest source, increasing from 17.8 EJ to 19.2 EJ.
- Buildings show the clearest emissions decline. Renewable heat in buildings grows 25% by 2031, renewable electricity overtakes bioenergy, fossil heat use falls 1%, traditional biomass declines 11% and heat-related CO_2 emissions drop 7%.
- Heat pumps and district heating provide key growth opportunities. Ambient heat harnessed by heat pumps grows nearly 6% per year, while district networks supply 17.7 EJ of heat but less than 7% from renewables. EU-like renewable shares in China and Russia would add around 6 EJ of renewable district heat.
- The renewables share of industrial heat demand rises from 16% to 19% by 2031, with renewable electricity providing around 70% of this growth. Fossil fuels supply more than 80% of industrial heat and heat-related CO_2 emissions fall 2%.
- Agriculture and clean cooking remain harder to shift. Agricultural renewable heat rises 21%, but fossil fuels still meet almost 90% of demand. Traditional use of biomass falls from 18.7 EJ to 16.7 EJ, yet access to clean cooking remains a major challenge, particularly in Africa.

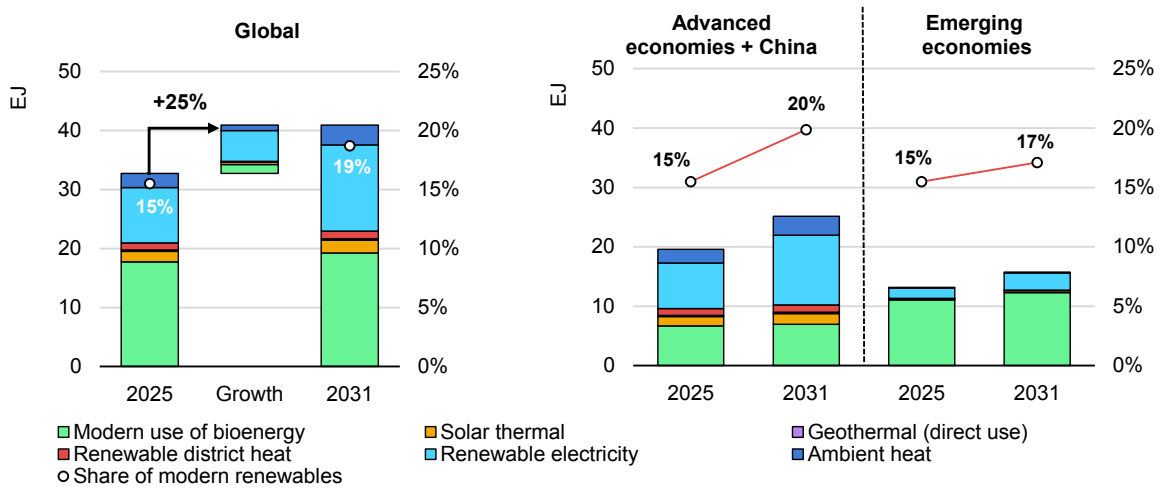
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Global summary

Electricity remains the main driver of renewable heat growth, led by China and the European Union

Renewable electricity used for heat accounts for around two-thirds of the increase in modern renewable heat to 2031. Modern bioenergy[12] remains the largest renewable heat source and continues to grow over the outlook period, although its share in renewable heat gradually declines as electricity-based heat expands more rapidly. Growth is concentrated among the economies most advanced in achieving Age of Electricity goals: China delivers around one-third of the increase, mostly through industrial electrification, while the European Union is the second-largest contributor, thanks primarily to buildings sector electrification.

Modern renewable heat consumption by source in selected regions, 2025-2031



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Source: IEA (forthcoming), World Energy Outlook 2026.

Heat accounts for around half of global final energy consumption and remains the largest source of energy-related CO_2 emissions. Nevertheless, the sector has received less policy attention than the power and transport sectors. With greater electrification and wider deployment of renewable heat technologies, the share of modern renewable energy sources in global heat demand rises from 15% in 2025 to 19% in 2031, cutting total heat-related CO_2 emissions roughly 4% over the period. While direct emissions from fuel combustion remain broadly

[12] Including solid biomass, liquid biofuels and biogases. In 2025 and throughout the outlook period, solid biomass makes up over 95% of modern bioenergy used globally for heating. Thus, the trends discussed in this chapter for modern bioenergy largely reflect developments in solid biomass. Chapter 4 provides a more detailed assessment of biogas and biomethane trends, including their use for heating.

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unchanged, indirect emissions decline as power sector decarbonisation steadily lowers the carbon intensity of electricity used for heat.

Three overarching drivers shape the outlook for renewable heat to 2031: electrification, energy security and energy access. In advanced economies, electrification (mainly through heat pumps) and increasing shares of renewables in electricity generation propel growth. Energy security concerns continue to support the deployment of domestic renewable heat sources and reduce exposure to fossil fuel price volatility and import dependence. In emerging markets and developing economies, renewable heat deployment remains closely linked to expanding energy access, improving clean cooking and reducing reliance on the traditional use of biomass.

Electrification and power sector decarbonisation reinforce each other

Renewable electricity used for heat expands more than 50% over the outlook period, rising from 9.4 EJ in 2025 to 14.6 EJ in 2031. Together with ambient heat captured by heat pumps, it accounts for three-quarters of renewable heat growth worldwide. In buildings, renewable electricity overtakes the modern use of bioenergy to become the largest renewable heat source.

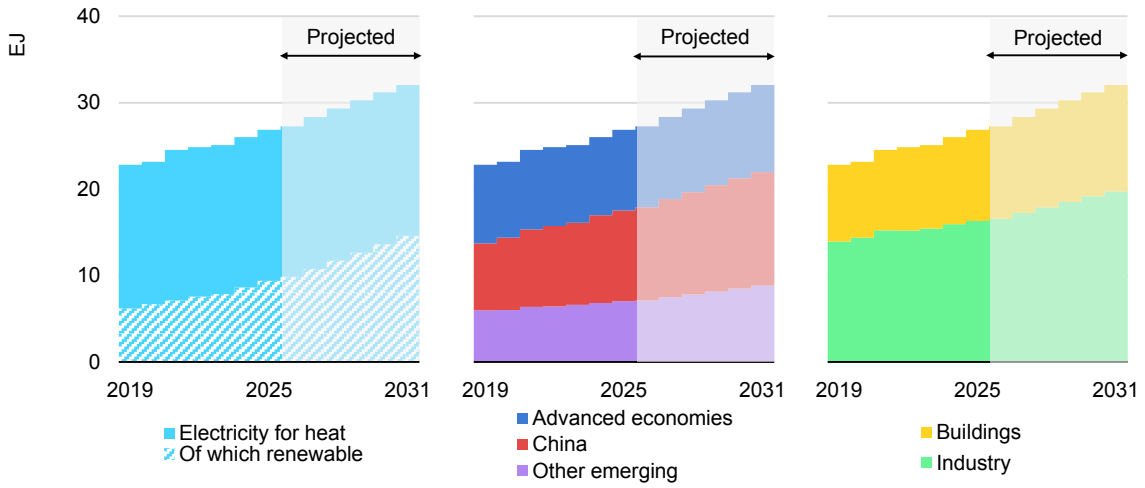
Rising electrification and power sector decarbonisation both drive growth. In industry, renewable electricity use for heat increases from 5.6 EJ to 8.9 EJ, led by process electrification in China. In buildings, it rises from 3.8 EJ to 5.7 EJ as heat pumps and electric water heating expand. At the same time, the renewable share of electricity used for heat increases from 35% to around 46%, amplifying the impact of electrification on renewable heat deployment.

The pace of electrification remains closely linked to energy prices and policy design. Electricity use for heat increases from 26.9 EJ to 32.1 EJ by 2031, but adoption depends on the relative cost of electricity and fossil fuels. Where taxes and levies keep electricity prices high relative to gas, the economic case for electrification remains weaker.

Heat pumps provide the strongest link between electrification and direct renewable heat. Ambient heat captured by heat pumps increases nearly 6% per year to 2031 – faster than any other direct renewable source. Most growth occurs in buildings, but larger systems also expand in low-temperature industry and district heating. Uptake remains highly sensitive to policy stability and the price of electricity relative to fossil fuels.

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Electrification of heat by region and sector, 2019-2031



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Notes: Electricity used for heat in industry has been revised upwards from *Renewables 2025*, reflecting a more granular split of energy-intensive sectors by end use and updated input data on the split by end use (heating, mechanical, lighting, cooling and other) based on the latest Manufacturing Energy Consumption Survey (MECS) data from the US Energy Information Administration (EIA).

Source: IEA (forthcoming), World Energy Outlook 2026.

Direct renewable heat remains the largest source, but provides only one-quarter of growth to 2031

Direct renewable heat[13] technologies are still the main source of renewable heat, but their contribution to growth is declining. Modern bioenergy, solar thermal and geothermal account for around 60% of renewable heat consumption in 2025 yet contribute only one-quarter of growth to 2031 as electricity-based heat expands more rapidly. This marks a significant shift from 2019-2025, when direct renewable technologies provided more than one-third of renewable heat growth. Together, these technologies expand 1.6% per year over the outlook period, compared with more than 7% for renewable electricity-based heat**.**

Solar thermal growth slows as China's market matures. Global consumption increases roughly 3.5% per year to 2031, a decline from recent years. China, which accounts for close to 70% of global deployment, records slower growth amid a continued slowdown in residential construction, an increasingly saturated domestic solar water-heating market and growing competition from heat pump water heaters. These trends outweigh stronger expansion elsewhere.

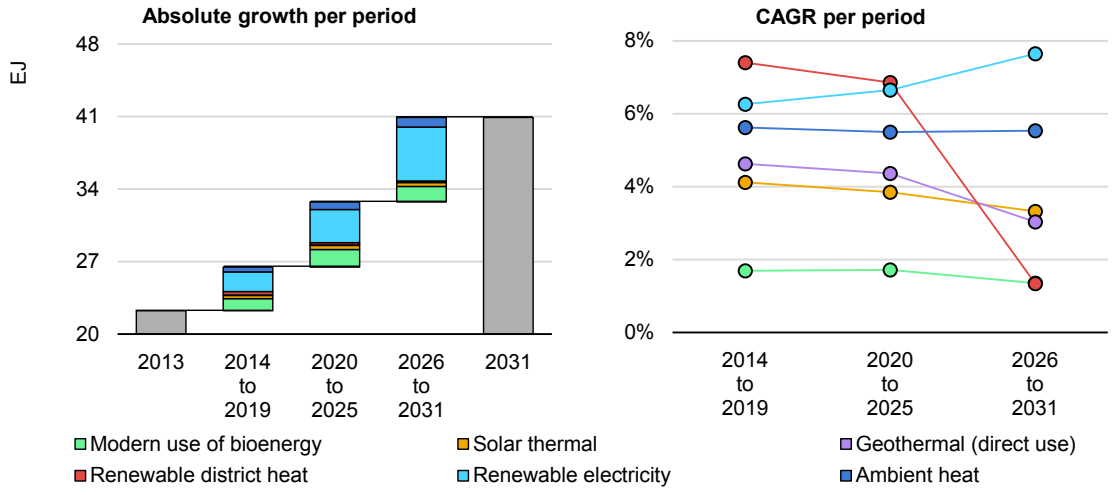
[13] Refers to renewable energy sources used directly to provide heat, including modern bioenergy, solar thermal and geothermal heat. Direct renewable heat excludes renewable heat supplied indirectly through electricity or district heating, as well as ambient heat captured by heat pumps, which requires an additional energy input, typically electricity, to be converted into useful heat.

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Modern bioenergy remains the largest renewable heat source, but growth is modest. Consumption rises from 17.8 EJ in 2025 at an average rate of 1.4% per year, with most additions occurring in industrial applications in emerging economies, particularly India. In buildings, consumption remains broadly stable as heat pumps continue to gain market shares and concerns over air quality constrain residential biomass-based heating.

Future growth opportunities for direct renewable heat are increasingly concentrated among large-scale applications. District heating, industrial heat and utility-scale projects offer the strongest prospects for expansion, particularly when combined with thermal storage. Short-duration, long-duration and seasonal storage can improve system performance and project economics by decoupling heat generation from demand, increasing operational flexibility and enabling greater utilisation of renewable heat sources. Recent developments, including geothermal district heating projects in Europe, declining costs for enhanced geothermal technologies, and the selection of solar thermal and geothermal projects under the first EU heat auction, highlight the growing role of large-scale systems in supporting further deployment.

Increase in global renewable heat consumption by source, 2014-2031



IEA. CC BY 4.0.

Note: CAGR = compound annual growth rate.
Source: IEA (forthcoming), World Energy Outlook 2026.

District heating remains the greatest untapped opportunity for renewable heat deployment

District heating networks are well established in many markets, but renewable integration remains limited. Networks delivered 17.7 EJ of heat in 2025 – around 8% of global heat demand – yet less than 7% came from renewable

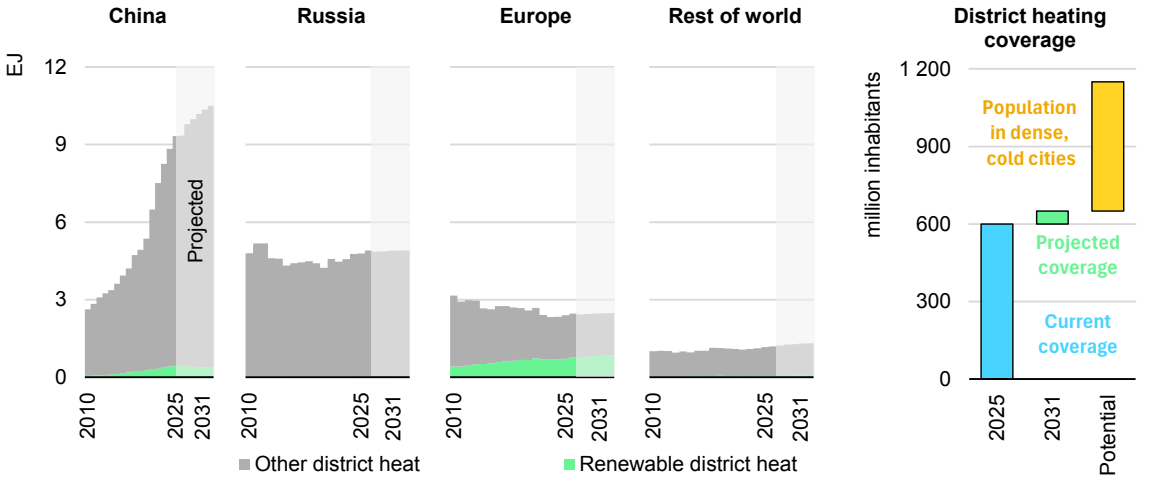
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sources. By 2031, district heat supply increases to 19.2 EJ, while the renewable share remains broadly unchanged, highlighting the slow pace of decarbonisation.

Significant opportunities to raise renewable shares in existing networks are concentrated in China and Russia, which account for the majority of fossil-fuelled district heat globally. China's district heating network supplies 9.3 EJ of heat, with renewables accounting for less than 5% of supply, while Russia's 4.8-EJ network remains almost entirely fossil fuel-based. Together, these two countries represent around four-fifths of global fossil-fuelled district heat, making them critical to the sector's decarbonisation.

Beyond existing systems, opportunities to expand networks in markets with low penetration but strong policy momentum are significant. Around 600 million people live in densely populated cold-winter urban areas with no access to district heating today. Moreover, experience in Denmark shows that district heating can also be viable outside of urban cores.

District heat consumption and potential in selected regions, 2010-2031



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Notes: District heat in IEA statistics refers to derived heat that is produced and sold, i.e. heat supplied to a distribution system or delivered under contract to third parties (persons or entities unrelated to the producer). It covers heat sold for use in buildings (residential and non-residential) and industry, including heat sold from combined heat and power (CHP) plants and heat-only plants, as well as recovered waste heat sold to third parties.

Source: IEA (forthcoming), World Energy Outlook 2026.

The European Union demonstrates the potential for higher renewable penetration in district heating systems. Renewables accounted for around 35% of EU district heat supply in 2025 and are projected to approach 42% by 2031, reflecting expansion in bioenergy, large-scale heat pumps, solar thermal and waste heat recovery. The EU Energy Efficiency Directive, which progressively tightens the criteria for efficient district heating and cooling systems, supports

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further deployment of renewables. This contrasts sharply with the global average and highlights the scale of remaining opportunities elsewhere.

Existing district heating networks offer the largest untapped opportunity to increase renewable heat consumption. Established district heating networks can accommodate substantially higher shares of renewables and recovered heat without major demand-side changes. If China achieved renewable shares comparable to the European Union's, global renewable district heat consumption would increase almost 4 EJ by 2031 – more than three times the current worldwide renewable district heat supply.

Waste heat potential is still untapped, but growing data centre demand and new mandates are raising policy attention

Waste heat remains a largely untapped source of renewable and recovered heat. Recovered heat from industry, data centres, wastewater and transport systems contributes to district heating in some markets, particularly in Europe, but deployment remains limited globally.

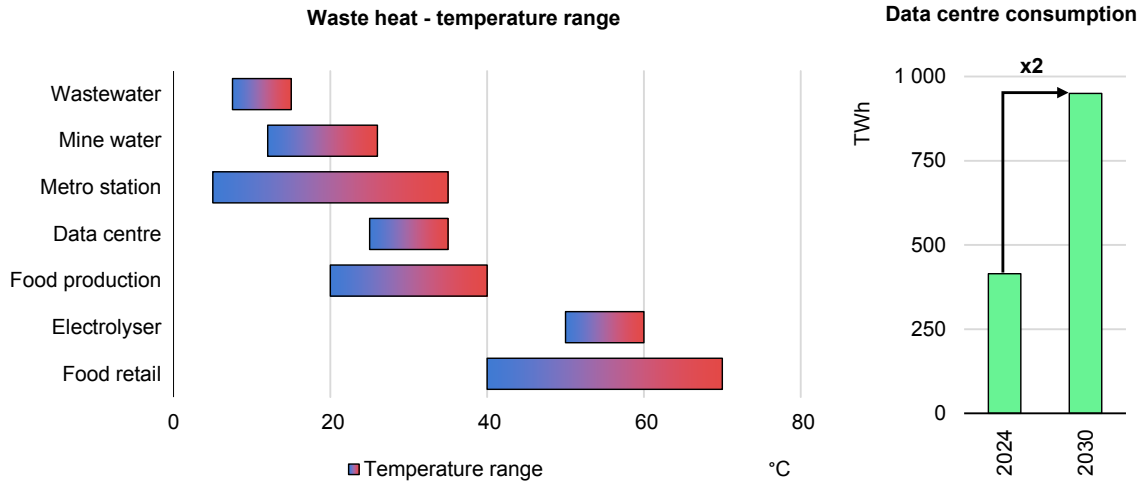
Technical potential is significant. Estimates indicate around 11 EJ of waste and renewable heat potential in the European Union for 2050, including around 6.5 EJ that is technically recoverable. In China, waste heat from industry, wastewater and data centres could provide around 10 EJ by 2050.

Growing data centre demand is turning policy attention towards waste heat recovery. Reused heat from data centres could provide up to 1 EJ of space heating by 2030 in areas located within 5 km of district heating networks, meeting the needs of around one in ten European homes. In fact, several European countries have already introduced targets or requirements for waste heat recovery. For instance, Germany has mandated at least 10% waste-heat reuse for new data centres from July 2026. While France, Sweden, Denmark and the Netherlands have set goals, major data centre operators are increasingly integrating heat recovery into district heating system plans.

District heating networks are the main pathway for large-scale waste heat use. However, wider utilisation depends on the availability of nearby heat demand and, in many cases, on heat pumps to upgrade lower-temperature heat streams. Where district heating infrastructure is already in place, waste heat can be a cost-effective additional low-carbon heat source.

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Waste heat sources for district heating and cooling, with temperature ranges, and data centre consumption, 2024-2030



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Notes: Data centre consumption projections correspond to the Base Case scenario of *Key Questions on Energy and AI*, which provides a central projection and considers trends in AI development, investment and bottlenecks in energy and IT supply chains.

Sources: IEA (2025), Opportunities for District Heating in the Changing Energy Landscape; IEA (2026), Key Questions on Energy and AI.

The traditional use of biomass declines globally, but clean cooking remains a major challenge, particularly in Africa

Traditional use of biomass remains widespread despite gradual declines over the outlook period. Consumption falls from 18.7 EJ in 2025 to 16.7 EJ in 2031.

Expanding access to clean cooking delivers significant health and socio-economic benefits. Household air pollution associated with traditional cooking practices contributes to around 2.5 million premature deaths annually.

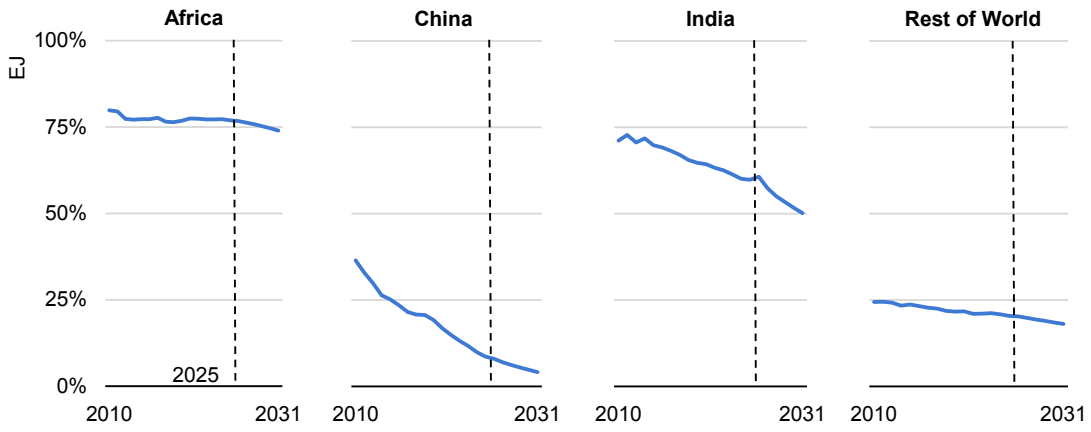
The global clean cooking challenge becomes increasingly centred around sub-Saharan Africa. Traditional biomass use rises from 6.5 EJ in 2010 to 8.9 EJ in 2031 as population growth outpaces improvements in clean cooking access, making the region the largest contributor to future growth in traditional biomass consumption**.**

Recent experience demonstrates that rapid transitions away from traditional biomass use are possible with proper policy focus. China reduces traditional biomass use almost 90% between 2010 and 2031, while Indonesia has cut its use by almost 80% by expanding access to liquefied petroleum gas (LPG).

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India's progress remains critical to the global outlook for clean cooking. Traditional biomass consumption declines from 4.3 EJ to 3.3 EJ by 2031 as LPG coverage expands, although affordability challenges continue to prevent a complete transition away from firewood in many households.

Share of traditional use of biomass in total final energy consumption for heat in selected regions, 2019-2031



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Source: IEA (forthcoming), World Energy Outlook 2026.

Buildings

Key points

- Modern renewable heat in buildings grows 25% to 2031, while fossil heat falls 1% and heat-related CO_2 emissions decline 7%.
- Nearly 60% of growth is in the European Union and China, raising the EU renewable heat share to 42% and China's to 27%.
- Renewable electricity becomes the largest renewable energy source in buildings sector heating by 2031, growing more than 50% to 5.7 EJ.
- Heat pumps provide most direct renewable heat growth, with ambient heat reaching 3.4 EJ and EU growth averaging 7.4% per year.
- Policy support diverges, gaining strength in the European Union, China, the United Kingdom and Japan while becoming more fragmented in the United States.
- District heat remains underused in buildings, with supply rising to 8.6 EJ but the renewable share increasing just slightly from 8% to 9%.

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Outlook summary

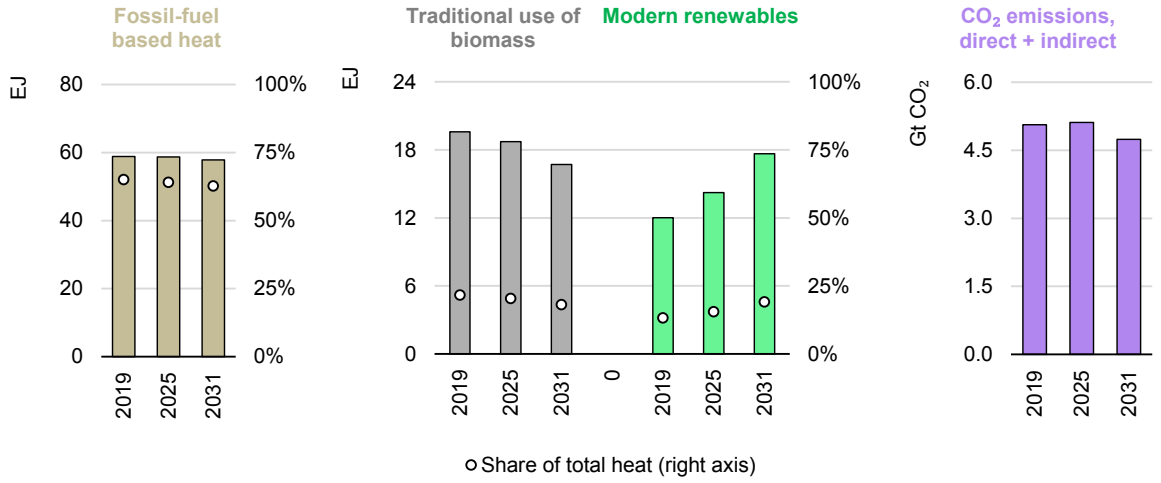
Modern renewable heat consumption grows 25% between 2025 and 2031. Growth accelerates compared with 2019-2025, thanks mainly to greater use of renewable electricity and heat pumps in China, the European Union and the United States, supported by renewable district heating in the European Union and continued solar thermal expansion in Asia. Renewable electricity overtakes modern bioenergy as the largest renewable heat source in buildings by 2031.

Fossil fuel-based heat consumption declines 1% between 2025 and 2031. The pace of decline accelerates compared with 2019-2025 as improvements in building efficiency and the replacement of fossil-fuel boilers – primarily by heat pumps – offset relatively stable heat demand.

Traditional use of biomass falls 11% between 2025 and 2031. The rate of decline accelerates compared with 2019-2025, supported by expanding access to clean cooking technologies.

Heat-related CO_2 emissions drop 7% between 2025 and 2031. After increasing slightly over 2019-2025, emissions fall as efficiency improvements, renewable heat deployment and power sector decarbonisation more than offset population growth.

Renewable and fossil heat consumption in buildings, shares of renewables in heat demand, and total CO_2 emissions related to heat, 2019-2031



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Source: IEA (forthcoming), World Energy Outlook 2026.

Regional trends and policy drivers to 2031

Mainly the European Union and China shape the outlook for renewable heat in buildings. Together, they account for almost half of modern renewable heat

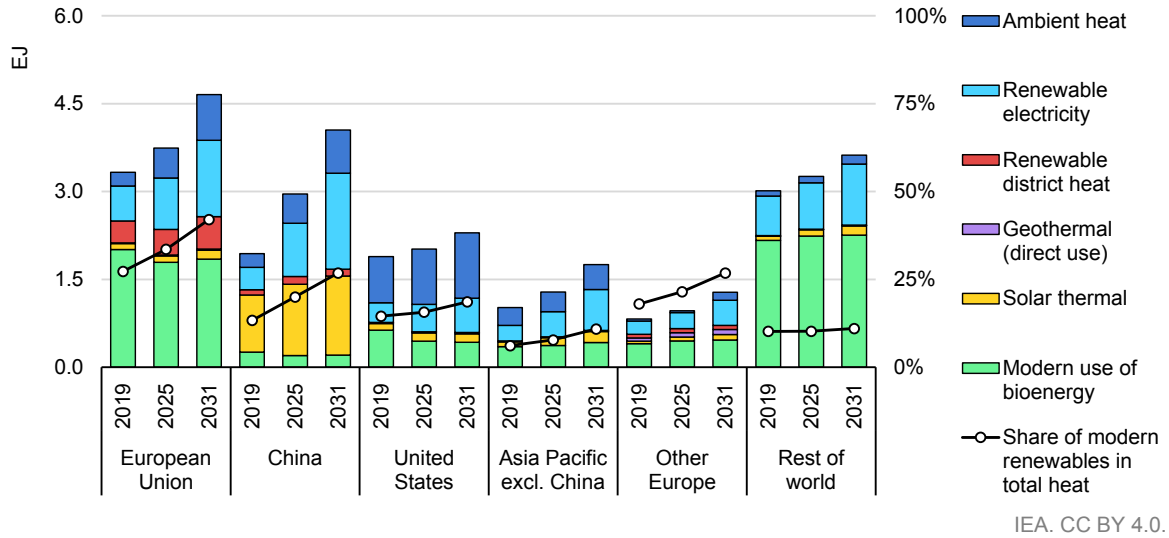
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consumption in buildings today and nearly 60% of the growth to 2031, increasing their renewable shares in electricity generation and expanding heat pump deployment.

The European Union records the largest increase in the renewable share of heat demand among major heat markets. Renewable heat consumption in buildings grows 0.9 EJ between 2025 and 2031, a rise of 34% to 42%. Renewable electricity and heat pumps account for most of the increase, while the European Union delivers almost all global growth in renewable district heat. Implementation of the Renewable Energy Directive III, the Energy Performance of Buildings Directive, the Energy Efficiency Directive and the EU Emission Trading System (EU ETS) 2 all strengthen the policy framework for renewable heat deployment, although support schemes increasingly vary across member states.

The Electrification Action Plan, published in July 2026, targets the electricity-to-gas price gap directly. It recommends that member states cut the price ratio to at most 2.5 for households and 2.0 for industry by 2030. If the legislative proposal published alongside the plan is adopted, it would require that excise duties on electricity be no higher than those on natural gas. It also aims to raise heat pump installations to 4 million per year by 2030. The forthcoming Heating and Cooling Strategy, expected later in 2026, is set to complement its directives on renewable and waste heat.

Renewable heat consumption in buildings and shares of renewables in heat demand in selected regions, 2019-2031



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Notes: Modern bioenergy in the "rest of world" category is used mostly for cooking. In some countries, data are limited and the boundary between the traditional and modern use of biomass is not clearly defined, making the split difficult to estimate.
Source: IEA (forthcoming), World Energy Outlook 2026.

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China accounts for the largest increase in renewable heat consumption in buildings, thanks primarily to electrification. Renewable heat in buildings rises 1.1 EJ, boosting the renewable share from 20% to 27%. Renewable electricity provides two-thirds of the increase, supported by grid decarbonisation, the expansion of electric heating and rising deployment of heat pump water heaters. While ambient heat consumption increases roughly 7% per year owing to policy incentives and subsidies (the 2025 national heat pump action plan and appliance trade-in support), solar thermal growth slows to around 2% per year as heat pumps capture an increasing share of water-heating demand.

The 15th Five-Year Plan's Renewable Energy Development Plan for 2026-2030, released in July 2026, further strengthens the outlook by targeting a 2.5-fold increase in non-power renewable energy use by 2030 relative to 2025, including low-emissions hydrogen, ammonia and methanol, biogas and biomethane, biofuels and renewable heat. Renewable district heat remains a relatively small contributor, with its share of district heating supply declining as fossil-fired capacity expands more rapidly.

The United States records the slowest renewable heat growth among major markets despite continued heat pump adoption. Renewable heat in buildings grows by only 276 PJ to 2031, or 2.2% per year, the slowest pace among major markets. Ambient heat accounts for around 60% of the increase, as heat pumps continue to gain shares where they offer lower running costs. However, expiration of the 25C and 25D federal tax credits after 2025, the rescission of updated HUD and USDA code requirements, and the review of federal efficiency standards make state-level measures – including building electrification requirements, carbon pricing schemes and rebate programmes – even more important.

A diverse mix of technologies and policy frameworks drives growth in other regions. Other European economies add 315 PJ of renewable heat consumption, led by the United Kingdom where the Boiler Upgrade Scheme runs to 2030 under the GBP 15-billion Warm Homes Plan and the Future Homes Standard takes effect from 2026-27. Meanwhile, Türkiye contributes with continued solar thermal and geothermal deployment. Heat pump water heaters underpin growth in Japan, and tighter building standards support expansion in Korea. India records the fastest growth among major emerging economies, with renewable heat consumption in buildings increasing 50%, spurred by solar water-heating requirements in building codes and state mandates. In sub-Saharan Africa, modern bioenergy for cooking underlies most growth as clean cooking programmes begin to scale up.

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Main policies underpinning the buildings sector renewable heat outlook for selected markets

Market	Main policy drivers	Direction
European Union	RED III, EPBD, EED, ETS2 with the Social Climate Fund and Electrification Action Plan; forthcoming Heating and Cooling Strategy; national grants (Germany's BEG, Italy's Conto Termico 3.0).	Regulation strengthening; grants less stable and varying by member state.
China	2025 national heat pump action plan and appliance trade-in schemes; 15th Five-Year Plan promoting non-fossil heat, waste heat recovery and heat pumps; 2026 Renewable Energy Development Plan (2026-2030) targeting a 2.5-fold increase in non-power renewable energy use by 2030, supporting renewable heating.	Strengthening.
United States	Expiry of 25C and 25D federal credits after 2025 and rescinded HUD/USDA code updates; state action (New York's All-Electric Buildings Act, carbon pricing in California and Washington, Inflation Reduction Act [IRA] rebate programmes).	Weakening federally; increasingly state-led.
United Kingdom	Boiler Upgrade Scheme funded to 2030 under the GBP 15-billion Warm Homes Plan; Future Homes Standard from 2026-27; policy costs removed from electricity bills.	Strengthening.
Japan	JPY 57-billion water heater programme, including heat pump water heaters, prioritising efficient, grid-connected models; mandatory building energy standards.	Stable and targeted.
Canada	Federal heat pump support through the Canada Greener Homes Affordability and Oil to Heat Pump Affordability programmes, complemented by provincial/territorial incentives and co-delivery arrangements.	Strengthening.

Note: "Direction" refers to changes in overall policy stance since the publication of *Renewables 2025*.

Policy momentum is nevertheless uneven among markets as well as instruments. The following matrix elaborates on market-level drivers (across the top) by showing the breadth of each policy framework and how it has changed since 2025. Incentives, building standards and district heating support are gaining strength in several European and Asian markets, while US federal support is weakening and carbon pricing for heat remains limited outside of the European Union.

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Policy momentum for renewable heat in buildings: Instrument coverage and direction since *Renewables 2025* in selected regions

Region	Renewable heat targets	Heat planning and mapping	Incentives and grants	Carbon pricing for heat	Building codes and MEPS	District heating support
European Union	▲		▲	▼	▲	
China	▲		▲			▲
United States			▼		▼	
United Kingdom		▲	▲		▲	▲
Japan			▲		▲	
Canada						

Comprehensive/in force. Partial/limited. None/minimal. Direction since 2025: ▲ stronger ▼ weaker.

Note: MEPS = minimum energy performance standards.

Source: IEA analysis based on IEA (2026), Policy Database, (accessed October 2026) and IEA (2026), Global Energy Policies Hub, (accessed October 2026).

Technology trends to 2031

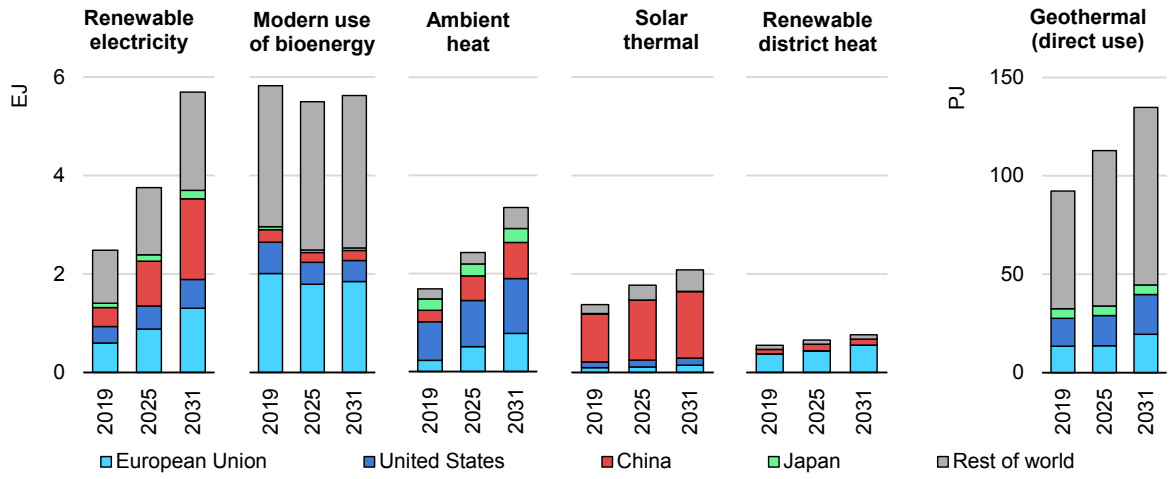
Electrification is reshaping the renewable heat mix in buildings. Renewable electricity expands more than 50% between 2025 and 2031, reaching 5.7 EJ of consumption and becoming the largest renewable heat source in buildings by the end of the outlook period, followed by modern bioenergy. Both rising electrification and an increasing share of renewables in power generation drive growth.

Modern bioenergy was the largest renewable heat source in 2025. Consumption remains broadly stable at around 5.5 EJ over the outlook period, as growth in modern cooking offsets the continued decline in wood-based heating in mature markets.

Heat pumps account for most direct renewable heat growth. Ambient heat captured by heat pumps increases to 3.4 EJ in 2031, supported by expanding deployment among residential, commercial and industrial applications.

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Renewable heat consumption in buildings by technology, 2025-2031



IEA. CC BY 4.0.

Source: IEA (forthcoming), World Energy Outlook 2026.

Modern bioenergy remains a major renewable heat source but growth slows

Consumption of modern bioenergy rises only marginally from 5.5 EJ in 2025 to 5.6 EJ in 2031, contributing just 4% of renewable heat growth. This is a marked slowdown from earlier decades, when biomass was the dominant source of renewable heat expansion. By 2031, renewable electricity overtakes bioenergy as the largest contributor to renewable heat in buildings.

Solid biomass accounts for more than 90% of modern bioenergy used for heating in buildings throughout the outlook period. Gaseous and liquid biofuels play smaller but locally important roles: biomethane blended into gas networks supports renewable heat in several European markets, while renewable liquid gases such as bioLPG can progressively lower emissions for existing off-grid LPG users, particularly where electrification is technically or economically constrained.

Policies in advanced economies increasingly favour electrification over biomass combustion in the buildings sector. In the European Union, implementation of the RED III, the Energy Performance of Buildings Directive and national renovation programmes is shifting support towards heat pumps and efficient electric heating. RED III strengthens sustainability and GHG-saving criteria for biomass fuels, tightening requirements for solid biomass in particular, while at the same time identifying biomethane production and injection into the gas grid as one of the measures member states can use to increase renewable

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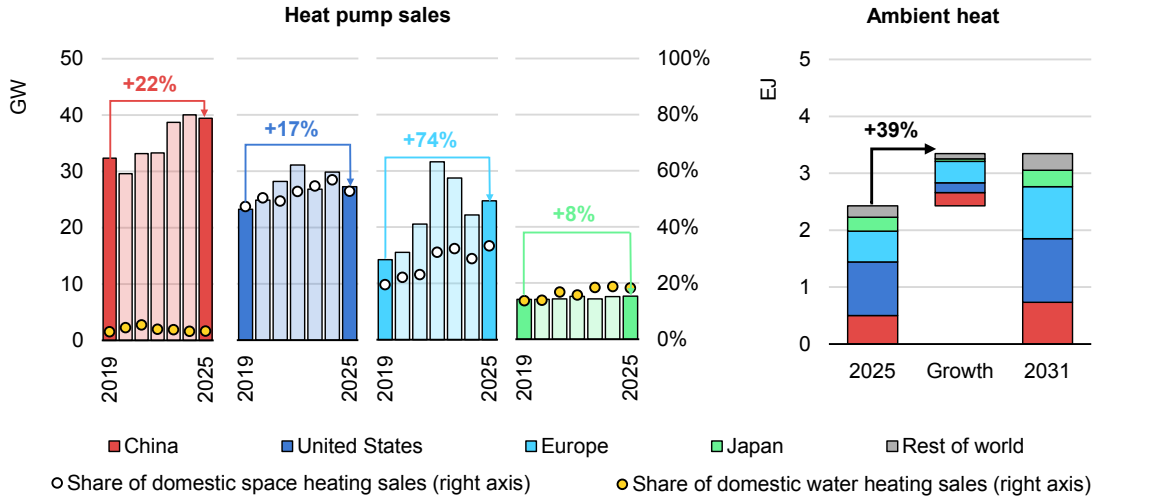
heating and cooling. Air pollution rules and stricter emissions requirements for residential appliances apply mainly to solid biomass, further constraining growth in wood heating.

Future bioenergy growth is concentrated in emerging markets and developing economies. In sub-Saharan Africa, modern bioenergy use expands as governments scale up clean-cooking programmes, while India continues to support biomass deployment through energy-access and cooking initiatives. As a result, most growth in modern bioenergy consumption to 2031 occurs outside of traditional space-heating markets.

Heat pumps lead growth, but expansion depends increasingly on policy support and running costs

Ambient heat is the fastest-growing direct renewable heat source in buildings, with heat pumps at the centre of our outlook. The amount of ambient heat captured by heat pumps increases nearly 6% per year to 2031. The United States remains the largest market, but growth is fastest in the European Union, at 7.4% per year, followed closely by China at 6.6%. Together with renewable electricity, heat pumps account for more than four-fifths of all growth in renewable heat consumption in buildings.

Heat pump sales and market shares in selected regions, 2019-2025, and ambient heat harnessed by heat pumps in buildings, 2025-2031



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Notes: Market shares are calculated as the share of decentralised heating equipment sales in each country and exclude district heating. For the United States and Europe, they cover space-heating equipment, while for China and Japan they cover equipment providing sanitary hot water.

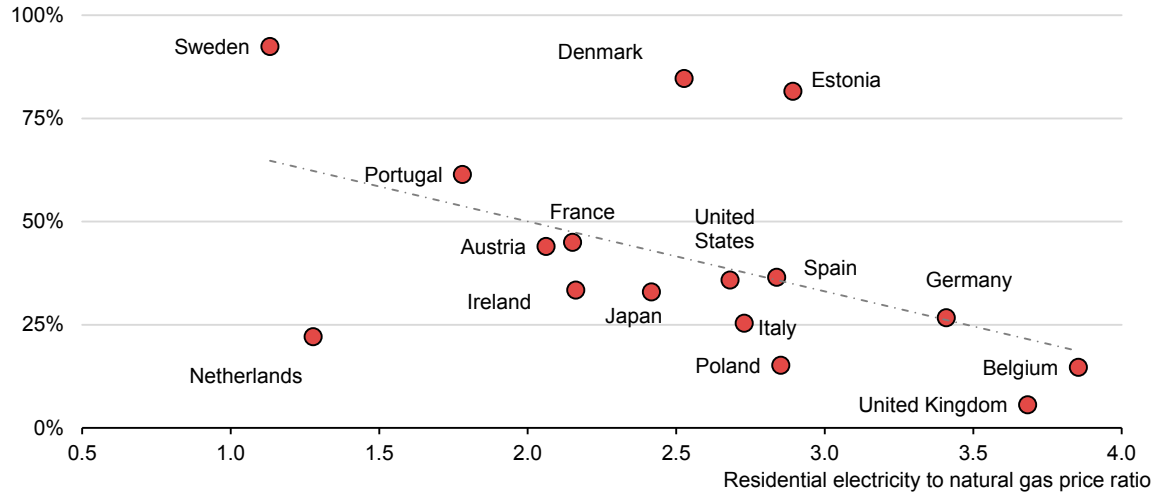
Sources: IEA (forthcoming), World Energy Outlook 2026; AHRI (2026), Monthly Shipments; EHPA (2026), Market Intelligence Interactive Platform, (accessed September 2026); JRAIA (2026), Independent statistics, (accessed October 2026); ChinaIOL (2026), ChinaIOL intelligence portal, (accessed October 2026).

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Recent market developments point to a recovery in heat pump sales, but market growth remains highly sensitive to policy support and energy prices. After three consecutive years of decline, European heat pump sales rose 13% to 2.9 million units in 2025. Germany became the largest market, with heat pumps making up almost half of new heating system sales, while deployment continued to expand in the United Kingdom. Across Europe, the sales ratio of fossil fuel-based boilers to heat pumps narrowed from 2.4:1 to 2.1:1. In contrast, purchases declined in France and Poland following changes to support schemes. In the United States, deployment is increasingly market-led: heat pumps outsold gas furnaces for a fourth consecutive year in 2025.

The key challenge to further deployment is increasingly economic rather than technological. Heat pump technologies are commercially mature, but their uptake remains closely linked to stable policy frameworks and the relative cost of electricity and fossil fuels. As a result, policy design and energy prices are becoming the main determinants of market growth in many regions.

Electricity-to-gas price ratio and heat pump market shares, 2024



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Source: IEA (2026), Heat Pump Monitor 2026.

Heat pump policy support is diverging across major markets in both design and direction. In the European Union, support increasingly combines upfront grants with measures to improve operating economics by narrowing the electricity-to-fossil-fuel price gap. US policy has become more fragmented since the withdrawal of federal tax credits, leaving state and territorial rebate programmes to provide much of the remaining support. While China treats heat pumps as an industrial policy priority, linking deployment incentives to manufacturing, efficiency

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and technology goals, Japan's focus is on efficient, connected water heaters that can shift demand towards daytime solar generation.

In Canada, federal programmes as well as provincial and territorial incentives support heat pump deployment, with policies increasingly targeting affordability for low- to median-income households. In France, the 2026 Electrification Action Plan aims for 1 million heat pump installations per year by 2030 and bans gas boilers in new buildings from January 2027, backed by a near-doubling of electrification support to EUR 10 billion per year. Elsewhere, approaches range from expanded grants and lower electricity costs in the United Kingdom to tighter eligibility, retargeting or broadly stable support in other European markets.

Selected heat pump policy developments and expected impacts in major markets, 2025-2031

Market	Key policy development	Expected impact on heat pump deployment
European Union	The Electrification Action Plan (July 2026) recommends cutting electricity-to-gas price ratios to at most 2.5 for households and 2.0 for industry by 2030, taxing electricity no more heavily than gas, and achieving 4 million heat pump installations per year by 2030.	**Supportive, but conditional.** Stronger common action should boost deployment, although energy price ratios will continue to limit near-term growth.
Germany	KfW heating grants cover 30-80% of eligible costs but phase down to 2030, and the new Building Modernisation Act repeals the 65% renewable heating mandate. A 2026 grid fee subsidy and levy exemption cut electricity costs.	**Supportive, but weakening.** High grants and lower running costs underpinned the sales recovery, but subsidy degression and the mandate-repeal temper growth later in the outlook period.
France	VAT is 20% for fossil fuel-based boilers, but just 5.5% for qualifying heat pumps. MaPrimeRénov' offers up to EUR 5 000 for air-to-water units. From September 2026, renovation aid for single-family homes excludes projects that retain gas heating.	**Supportive, but policy changes may disrupt delivery.** Tax treatment and the new renovation condition favour heat pumps; repeated revisions can delay household decisions.
Italy	Conto Termico 3.0 entered into force in December 2025. It provides EUR 900 million annually and up to 65% capital support for efficiency and renewable heat, including heat pumps.	**Supportive.** Broader eligibility and predictable funding should strengthen replacement demand in homes and tertiary buildings.
United Kingdom	The Boiler Upgrade Scheme grants GBP 7 500 for hydronic heat pumps and GBP 2 500 for air-to-air units, with funding to 2030. The Warm Homes Plan also removes some policy costs from electricity bills.	**Strongly supportive.** Long-term grants and lower electricity costs should broaden deployment, including of air-to-air systems.
Other European markets	Belgium raised its VAT on fossil boiler installations to 21%, while qualifying heat pumps remain at 6%. Poland relaunched Czyste Powietrze with tighter cost and eligibility controls. The Netherlands kept ISDE support broadly stable in 2026.	**Divergent.** Belgium is improving heat pump economics; Poland is prioritising targeting and quality; and Dutch changes are broadly neutral for new demand.

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Market	Key policy development	Expected impact on heat pump deployment
United States	Federal 25C and 25D credits ended 31 December 2025. State, territorial and tribal Home Energy Rebates continue to support heat pumps, but implementation varies.	**Weakening and fragmented.** Rebate programmes partly offset the federal withdrawal, but uneven coverage should slow growth relative to other major markets.
China	The six-ministry Heat Pump Action Plan sets 2030 goals for product efficiency, deployment, manufacturing and research. Provincial 2026 appliance trade-in programmes also cover heat pumps.	**Supportive.** Industrial policy and consumer subsidies should sustain rapid growth, especially in water heating and rural applications.
Japan	The JPY 57-billion 2026 programme offers JPY 70 000-100 000 per heat pump water heater, plus removal bonuses. The programme prioritises models that connect to the Internet and shift heating towards daytime solar generation.	**Targeted and system friendly.** Subsidies should accelerate efficient water heater uptake while increasing flexible demand and renewable power use.

The electricity-to-gas price ratio is becoming a key determinant of heat pump deployment. Where taxes and levies keep electricity prices high relative to gas, the economic case for electrification weakens despite efficiency gains. Policy reforms to electricity pricing and introduction of the ETS2 are expected to improve the competitiveness of electric heating over time, while the Social Climate Fund aims to mitigate impacts on vulnerable households.

District energy remains a largely untapped renewable heat lever

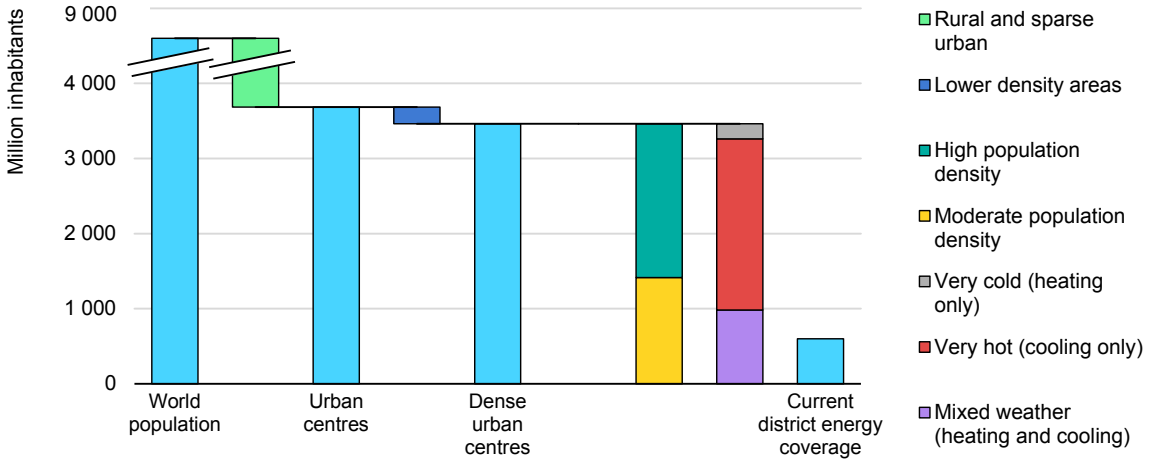
District heating still offers one of the greatest untapped opportunities to increase renewable heat in buildings. Although district heat supplied to buildings rises from 8 EJ in 2025 to 8.6 EJ in 2031, the renewable share increases only marginally from 8% to 9%. This contrasts sharply with the potential of existing network infrastructure, which could accommodate substantially larger volumes of renewable and recovered heat without requiring new end-use equipment.

The European Union continues to lead almost all growth in renewable district heating. The renewable share of district heat rises from 35% to 43% by 2031 as countries accelerate their deployment of large heat pumps, bioenergy, geothermal heat and waste-heat recovery. Several important policy developments have strengthened our outlook since last year: the Netherlands adopted its Collective Heat Act in late 2025; Germany continues to expand support through the Bundesförderung für effiziente Wärmenetze (BEW) scheme; France maintained its EUR 800-million Fonds Chaleur programme; and Italy's Conto Termico 3.0 increased support for district-heating connections.

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China illustrates how network expansion alone does not guarantee decarbonisation. Although district heat supplied to buildings increases strongly, renewable penetration remains low and declines slightly as new fossil-fuelled capacity expands faster than renewable alternatives. This contrast with Europe highlights a key message: while the infrastructure challenge has largely been solved in many markets, the hurdle now is to replace fossil heat sources with renewable and recovered heat.

Global population by settlement density and heating and cooling needs, 2025



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Notes: Population and density data are based on the Global Human Settlement Layer (GHSL) Urban Centre Database (R2024A), which includes data on 11 422 quality-controlled urban centres worldwide. Urban centres are defined as contiguous areas with at least 50 000 inhabitants and a minimum population density of 1 500 people per square kilometre. Heating demand is approximated using population-weighted heating degree days (HDDs, base 18°C), derived from the IEA Weather, Climate and Energy Tracker. Population is filtered based on urbanisation, heating needs and density thresholds to identify areas where district heating is more likely to be cost-competitive.

Source: Pesaresi, M. et al. (2024), Advances on the Global Human Settlement Layer.

Solar thermal growth slows as markets increasingly favour electrification

Solar thermal remains the third-largest source of direct renewable heat in buildings today, but its growth has slowed. Consumption rises from 1.8 EJ in 2025 to 2.1 EJ in 2031, equivalent to roughly 3% annual growth – 6 percentage points less than during the 2010s. This slowdown reflects increasing competition from heat pump water heaters, particularly in markets that have traditionally driven global deployment.

China continues to shape the global outlook for solar thermal. Accounting for around two-thirds of worldwide solar thermal consumption, China's market expands by only about 2% per year as heat pump water heaters increasingly replace solar energy systems in the residential water-heating segment. This marks

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a major change from the previous decade, when Chinese deployment made up most global solar thermal growth.

Future growth will depend increasingly on regulatory mandates rather than direct subsidies. India continues to expand deployment through the solar water-heating requirements embedded in its building energy codes – the ECBC and the Eco Niwas Samhita, now being consolidated under the Energy Conservation and Sustainable Building Code. Meanwhile, building regulations and social-housing requirements support growth in parts of the Middle East and Brazil. In Europe, the policy focus is gradually shifting towards larger-scale applications: Germany's BEW provides operating support to feed solar thermal into heat networks, while Italy's Conto Termico 3.0 extends incentives to solar thermal supplying district heating within its small-scale scope.

Beyond directly competing with heat pumps, solar thermal can be a complementary technology: in Europe in particular, hybrid systems that pair solar thermal or photovoltaic-thermal (PVT) collectors with heat pumps are increasingly being deployed to raise overall system efficiency and reduce electricity demand. While this is still a niche innovation, it indicates that solar thermal can support – not only compete with – electrified heating.

Geothermal deployment remains limited in buildings, but policy support is strengthening growth prospects

Direct-use geothermal remains the smallest renewable heat technology in buildings. Although consumption is rising from 113 PJ in 2025 to 135 PJ by 2031 (growth of around 3% per year), geothermal still accounts for less than 1% of modern renewable heat consumption in buildings. However, these figures understate geothermal's broader contribution, since ground-source heat pumps are counted under ambient heat, and geothermal energy supplied via district heating is recorded separately.

Growth remains concentrated in a small number of markets. Türkiye continues to dominate global direct-use geothermal deployment, while much of the remaining growth occurs in the European Union, particularly in France, Germany, Hungary and the Netherlands. Expansion in Europe accelerates to around 6% annually as municipalities increasingly incorporate geothermal resources into heat-planning strategies and district-heating decarbonisation plans.

Policy developments increasingly focus on reducing exploration and development risks rather than subsidising operating costs. Long-standing exploration-risk guarantees in France and the Netherlands continue to underwrite the drilling phase (France reinforced its deep-geothermal guarantee fund with EUR 195.6 million of approved state aid in 2023), and Germany joined them in December 2025 when KfW and Munich Re launched federally backed loans with discovery-risk cover enabled by the Geothermal Acceleration Act. Meanwhile,

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municipal heat-planning requirements under the Energy Efficiency Directive – mandatory for municipalities with more than 45 000 inhabitants – are creating a clearer pathway from resource identification to long-term heat demand.

Higher cooling demand can raise renewable energy use in heating

Extreme heat waves are becoming more frequent in an increasing number of countries. The past 11 years were the warmest on record, and in 2026 western Europe experienced its hottest June ever. The late-June heat wave was linked to more than 10 000 excess deaths across Europe in one week. Unsurprisingly, rising temperatures are boosting cooling demand: in fact, space cooling is the fastest-growing energy consumer in buildings, with around 132 million air conditioning units sold worldwide in 2024.

Most of these units can heat as well as cool. Nearly all room air conditioners now sold in the European Union and Japan are reversible, and such systems also dominate heating across central and southern China. Their contribution to renewable heat production can be significant when they are used in heating mode: in Italy, reversible air-to-air heat pumps supplied around 33 TWh of renewable heat in 2023, accounting for more than one-quarter of the country's renewable heat that year. However, utilisation remains limited, with fewer than half of reversible units installed in the European Union used for heating.

Policy frameworks can ensure that rising cooling demand also supports renewable heat deployment. Building standards and product labels can reward heating performance alongside cooling efficiency, while incentive schemes can include reversible air conditioners that meet minimum performance criteria. Germany already provides support for such systems, whereas standalone units are still excluded in France and Spain. As cooling demand expands, policy design will increasingly determine whether new installations also contribute to renewable heating.

District cooling systems can also be used to meet rising cooling needs while supporting renewable energy integration. Sharing many features of district heating, district cooling networks supply cooling from natural sources, waste heat, large-scale chillers, heat pumps and thermal storage. They can reduce summer electricity peaks, absorb surplus renewable generation and ease pressure on urban grids.

Renewable heat technologies can unlock significant flexibility

Renewable heat technologies can shift electricity demand at a scale that supports power system flexibility. Hot water tanks, heat batteries and district heating networks can store low-cost renewable electricity, raising demand during periods of abundant wind and solar generation and reducing consumption during peak demand periods.

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Flexibility needs are increasing as power systems integrate higher shares of variable renewables. Wholesale electricity prices were negative in 6% of hours in France, Germany, the Netherlands and Spain in 2025, while the European Union overall curtailed more than 20 TWh of renewable electricity generation. At the same time, heating contributes to winter peak demand, creating a growing need for load flexibility. Renewable heating can support both objectives by increasing consumption during periods of surplus generation and reducing demand during peak periods.

Much of this flexibility can be unlocked using existing assets. Utilising a building's thermal mass to store heat can shift heating demand for several hours, while hot water tanks and heat batteries can extend flexibility to around half a day. District heating networks and thermal storage can provide flexibility over days or even seasons, making renewable heat an increasingly valuable source of system flexibility. Thermal storage also supports direct renewable heat systems, particularly solar thermal, by shifting supplies across daily to seasonal timescales.

Renewable heat assets, flexibility mechanisms and response times

Asset class	Flexibility mechanism	Main service	Response and duration
Distributed heat pumps	Pre-heat buildings or charge buffer and hot-water tanks; smart controls modulate or pause compressors.	Load increase and load reduction	Minutes; 0.5-3 h from thermal mass and 2-12 h with storage
Water heaters and behind-the-meter storage	Shift cylinder or heat-battery charging without interrupting hot-water service.	Both; particularly year-round surplus absorption	Minutes; 2-12 h
Large heat pumps and electric boilers in district heating	Use spare power-to-heat capacity in surplus hours and reduce operation at peaks; storage decouples output from demand.	Both; particularly load increase	Minutes; hours depending on storage
District networks and thermal storage	Network inertia, tanks and underground stores buffer heat and enable source switching.	Extends power-to-heat and balances heat supply	Minutes to hours; 2-24 h to seasonal
Solar thermal with storage	Store solar heat for later use, reducing other heat production and thermal peaks.	Heat-side flexibility; no direct electric response	Diurnal to seasonal
Hybrid heat pumps	Temporarily switch from the heat pump to a backup boiler during periods of system stress.	Load reduction through fuel switching	Minutes; hours to days

Notes: "Load increase" means shifting electricity use to surplus-renewable periods; "load reduction" means shifting it away from system peaks. Durations are indicative. Storage and networks extend power-to-heat flexibility and are not added as separate GW_e.

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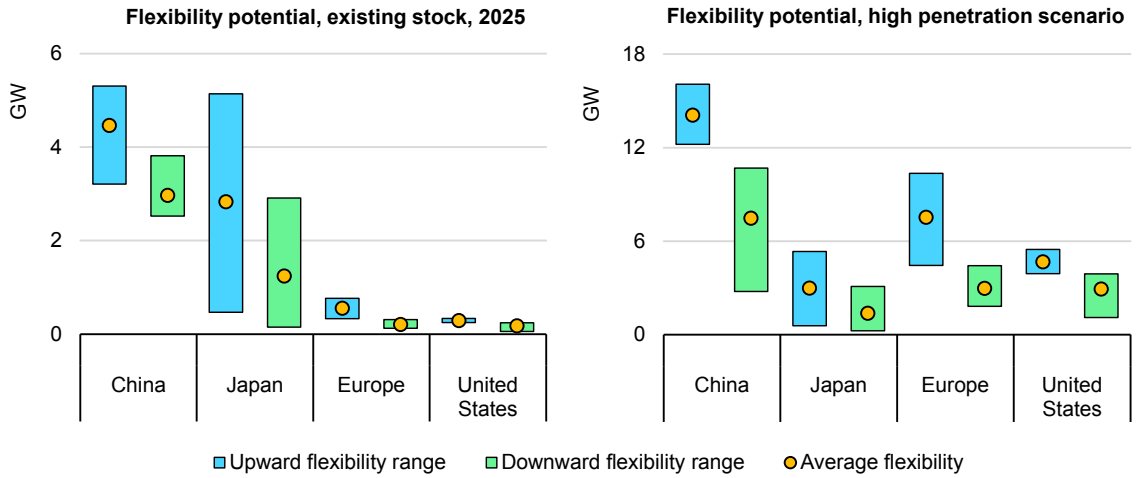
Heat pump water heaters can provide flexibility throughout the year. Hot-water demand is less seasonal than space heating, and storage tanks enable water heating to be shifted ahead of demand**.** This enables operators to shift electricity use towards periods of abundant renewable generation and away from system peaks, while maintaining hot-water supply.

The estimated global heat pump water heater fleet comprised around 25 million units in 2025, with 40 GW of connected electrical capacity. Although only part of this capacity is available at any given time, a fully controllable and responsive fleet could provide substantial flexibility. It could increase electricity demand by 8.3 GW or reduce it by 4.7 GW, averaged over four-hour events at different local start times.

Of the major markets, Japan has the highest estimated household penetration of heat pump water heaters (around 14%), providing a benchmark to assess how wider adoption could expand flexibility. In a scenario in which all markets reach Japan's household deployment share, global connected electrical capacity would reach roughly 270 GW. If fully controllable and responsive, this larger fleet could increase electricity demand by 73 GW or reduce it by 28 GW (average responses over four-hour events).

Available flexibility would still vary throughout the day as tanks charge and hot water is consumed. Each region would retain its own charging patterns, rather than adopt Japan's mainly overnight operation. Smart controls and appropriate incentives would help align charging with local power system needs while preserving hot-water availability.

Heat pump water heater electrical capacity and four-hour flexibility, current vs Japan-level deployment



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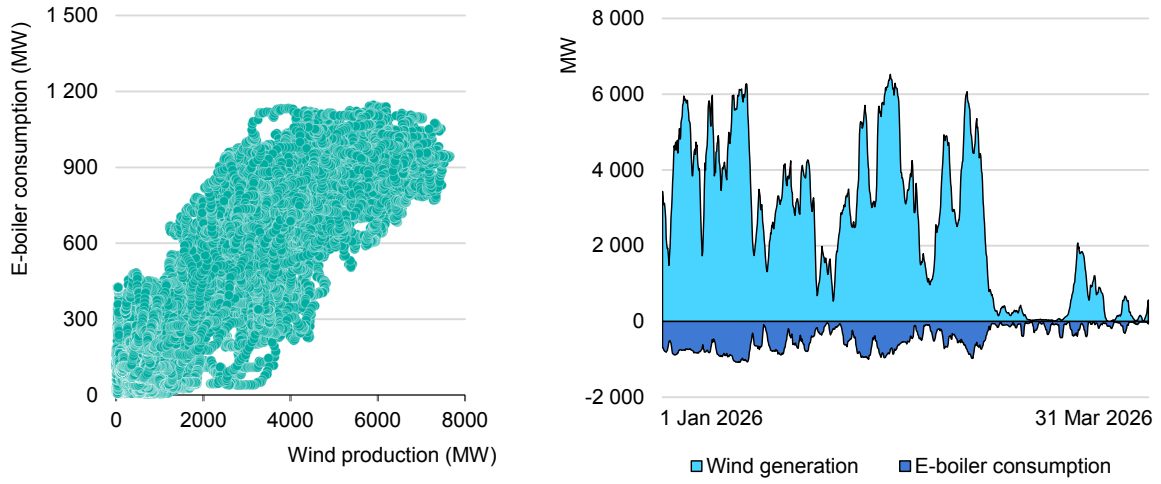
Notes: Current-fleet estimates refer principally to 2025 and cover Europe, China, the United States, Japan, Australia and New Zealand. The counterfactual "high penetration scenario" uses Japan as the deployment benchmark while retaining regional equipment and operating assumptions. Responses are averages over four-hour events and across local start times, with restoration of the starting tank inventory within 24 hours. Regional opportunities do not represent a synchronised global event.

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Electrifying district heating can provide flexibility at scale. District heating networks can combine large heat pumps and electric boilers with thermal storage to adjust electricity consumption. Operators can increase demand when renewable generation is abundant and reduce it during system peaks, while stored heat maintains supply to customers. Having several heat sources provides further scope to change electricity use without interrupting heating.

Finland illustrates how this flexibility can support the power system. Electric boiler capacity in district heating reached around 1.5 GW by October 2025. These installations increasingly combine boilers with thermal storage, allowing operators to take advantage of low electricity prices. Electric boilers produced approximately 2 700 GWh of district heat in 2025, up from around 1 500 GWh in 2024.

Wind power generation and electric boiler consumption in Finland, Q1 2026



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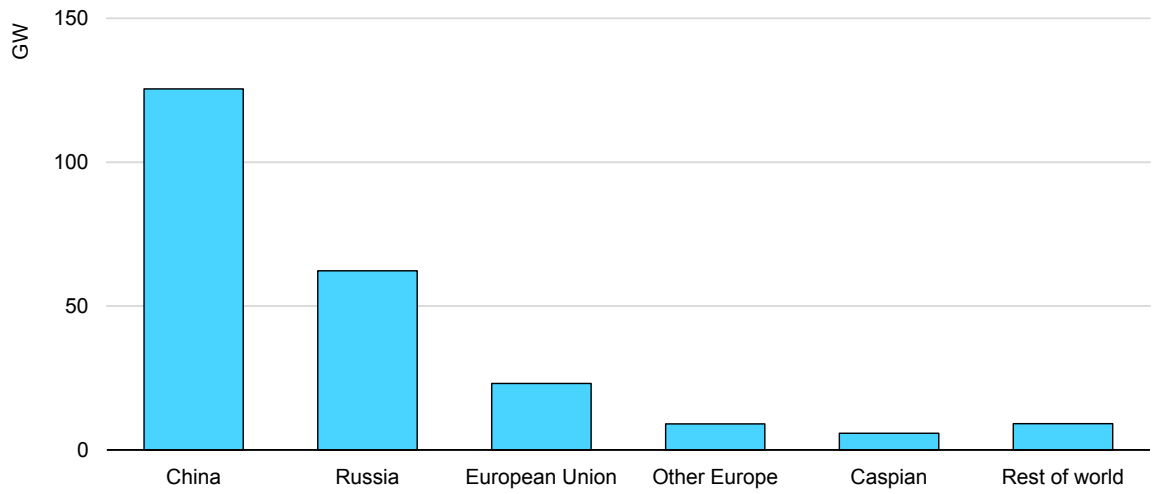
Notes: Wind power generation data have a 3-minute resolution. Electric boiler (e-boiler) consumption data have a 1-minute resolution, averaged to 3-minute intervals. Each data point is a paired wind-e-boiler observation for a 3-minute interval. Data cover 1 January 2026 to 31 March 2026. Electric boiler consumption is the sum of grid-measured electric boilers, mainly serving district heating.

Source: IEA analysis based on FinGrid (2026), FinGrid open data, (accessed July 2026).

If all regions matched Finland's electric boiler deployment relative to annual district-heat consumption, global potential of dispatchable e-boiler capacity would reach around 235 GW. This would create a large pool of dispatchable electricity demand in countries with large district heating networks, with China and Russia accounting for around 80% of the total. The capacity available to increase or reduce consumption at any moment would depend on existing operation, heat demand and storage availability.

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Electric boiler capacity if all regions matched Finland's district heating system design, 2025



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Notes: Capacity is expressed as electrical input in GW. The scenario applies Finland's benchmark of 48.4 MW of electrical capacity per TWh of annual district-heat consumption to each region's 2025 demand. The benchmark uses an October 2025 capacity estimate of 1 500 MW, treated as heat output and converted at 99% efficiency, and annual delivered heat of 31.3 TWh. Values represent total capacity in the counterfactual scenario, including any existing installations. Available flexibility depends on operating conditions, heat storage and electricity network constraints.

Sources: IEA district heating estimates for 2025; Finnish Energy (2026), District heating statistics; Vantaan Energia (2025), Martinlaakso's Electric Boiler and Thermal Battery to be Commissioned.

Large heat pumps could expand this resource while using less electricity per unit of heat supplied. If they provided 10-40% of annual district-heat production in every region, their potential flexible electrical capacity would reach 40-160 GW. Together with electric boilers deployed at Finland's benchmark, combined potential capacity would amount to 280-400 GW. These estimates assume heat pumps produce three units of heat per unit of electricity and operate for 4 000 equivalent full-load hours annually.

A central case, with heat pumps supplying 20% of annual district heat, would have around 320 GW of combined electrical capacity potential. If fully controllable and responsive, the fleet could increase electricity consumption by around 228 GW or reduce it by 87 GW for four hours under average heat-demand conditions. These are alternative responses relative to baseline operation, with heat supply maintained throughout each event.

Operating conditions would shape the flexibility available throughout the year. High heat demand leaves less spare capacity to increase electricity consumption, while reducing consumption requires stored heat or alternative heat production. Greater heat pump deployment would expand the scope to reduce demand, but storage limits how much additional electricity the system can absorb.

Realising this potential would require co-ordinated investment in electric heat production, storage and grid connections. Electricity prices that reflect system

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conditions, automated controls and access to flexibility markets would help operators adjust consumption while maintaining reliable heat supply.

Industry

Key points

- Modern renewable heat in industry increases 25% to 2031, raising its share in industrial heat demand from 16% to 19%.
- Industrial heat-related CO_2 emissions fall 2%, owing mainly to lower indirect emissions as electricity generation decarbonises.
- China and India provide almost two-thirds of growth, through industrial electrification in China and bioenergy use in India.
- Renewable electricity underpins around 70% of industrial renewable heat growth, expanding almost 60% to 8.9 EJ by 2031.
- Modern bioenergy remains the largest energy source, rising to 12.9 EJ, but its share falls to below 60% as electrification accelerates.
- Solar thermal and geothermal remain niche technologies, while thermal storage improves the economics of renewable industrial electrification.

Outlook summary

Modern renewable heat consumption in industry expands 25% between 2025 and 2031, in line with growth over 2019-2025. Renewable electricity[14] accounts for around 70% of the increase, led by China, India and the European Union, while modern bioenergy underpins most of the remaining growth. The renewables share in industrial heat demand rises from 16% in 2025 to 19% in 2031.

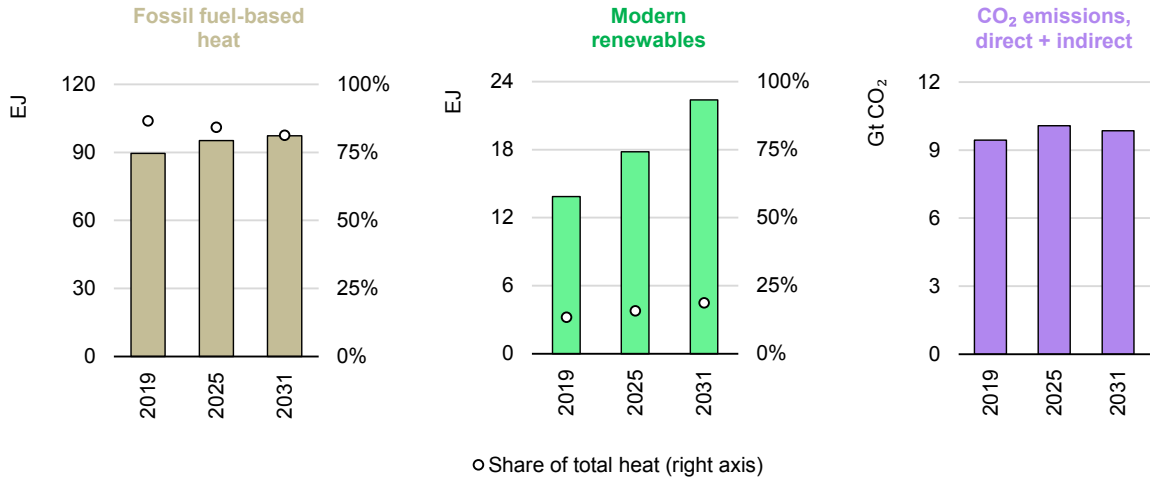
Fossil fuel-based heat consumption remains broadly flat, increasing only 2% between 2025 and 2031. Slower growth than in 2019-2025 reflects rising renewable energy deployment, but growing heat demand in emerging economies continues to limit fuel substitution. Fossil fuels still meet more than 80% of industrial heat demand in 2031.

[14] Electricity used for heat in industry has been revised upwards from *Renewables 2025*, reflecting a more granular split of energy-intensive sectors by end use and updated input data on the split by end use (heating, mechanical, lighting, cooling and other) based on the latest MECS data from the US Energy Information Administration.

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Heat-related CO_2 emissions in industry decline 2% between 2025 and 2031, reversing the 7% increase recorded over 2019-2025. Lower indirect emissions are almost wholly responsible for this reduction as power sector decarbonisation cuts the carbon intensity of electricity. Direct emissions from fuel combustion remain broadly flat, reflecting the limited decline in fossil fuel use across industry.

Renewable and fossil heat consumption in industry, shares of renewables in heat demand, and total CO_2 emissions related to heat, 2019-2031



IEA. CC BY 4.0.

Source: IEA (forthcoming), World Energy Outlook 2026.

Regional trends and policy drivers to 2031

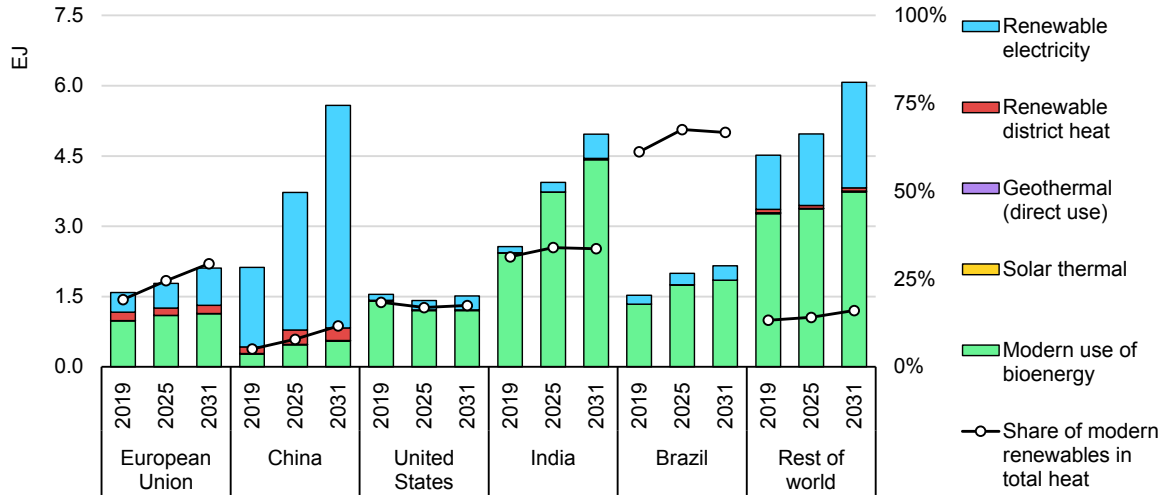
China and India are responsible for almost two-thirds of global renewable heat growth in industry to 2031, but through different pathways. Together they account for more than 40% of renewable heat consumption in industry today. Growth in China is overwhelmingly underpinned by renewable electricity and industrial electrification, while India's expansion relies primarily on modern bioenergy, much of it sourced from industrial by-products. The European Union follows as the third-largest contributor, accounting for around 7% of global growth.

China shows the largest increase in renewable heat consumption in industry, owing almost entirely to electrification. Renewable heat consumption rises 1.9 EJ between 2025 and 2031, boosting the renewable share in industrial heat demand from 8% to 12%. Renewable electricity accounts for nearly all growth as grid decarbonisation raises the renewable share of electricity used for industrial heat from 37% to almost 50%. Direct connections to captive solar and wind projects, often combined with thermal storage, could nearly halve the cost of electrified steam. The 15th Five-Year Plan's (FYP) Renewable Energy

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Development Plan, released in July 2026, supports this trajectory by targeting a 2.5-fold increase in non-power renewable energy use by 2030 from 2025 levels, including for industrial applications.

Renewable heat consumption in industry and shares of renewables in heat demand in selected regions, 2019-2031



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Source: IEA (forthcoming), World Energy Outlook 2026.

India remains the largest consumer of direct renewable heat in industry and accounts for one-quarter of global growth to 2031. Renewable heat consumption increases by 1.0 EJ, with bioenergy providing two-thirds of the growth. Expansion is concentrated in agro-industrial sectors such as sugar, pulp and paper, and rice processing, where bagasse, black liquor and rice husks provide low-cost process heat and steam. India also records the largest increase in industrial solar thermal deployment, while electrification continues to advance more gradually, with electricity meeting 9% of industrial heat demand by 2031, up from 7% in 2025.

The European Union records the largest renewable-share increase in industrial heat demand among major markets. Renewable heat use expands 330 PJ between 2025 and 2031, increasing its share in industrial heat demand from 25% to 29%. Renewable electricity accounts for over 80% of this growth, with power sector decarbonisation raising the renewable share of electricity used for industrial heat from 48% to 64%. The European Union is also the only region for which renewable district heat supplied to industry grows meaningfully.

In North America, the United States records the slowest renewable industrial heat growth among major markets due to a weaker federal policy framework. Renewable heat consumption increases just 94 PJ by 2031, with the renewable share in industrial heat demand flattening at around 17%. Despite weakening of

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the federal policy framework, industrial heat storage continues to advance in energy-intensive sectors where low-cost electricity or tailored tariffs improve project economics. In Canada, the Clean Technology Investment Tax Credit provides tax support for eligible heat pump investments, while the Green Industrial Facilities and Manufacturing Program supports broader industrial energy efficiency and decarbonisation.

Main policies underpinning the industry sector renewable heat outlook for selected markets

Market	Main policy drivers	Direction
China	The April 2025 Heat Pump Action Plan promotes waste-heat recovery for industrial steam and high-power, high-temperature heat pumps. The 15th FYP's Renewable Energy Development Plan (2026-2030) targets a 2.5-fold increase in non-power renewable energy use by 2030, supporting renewable heating.	**Strengthening.** Extends heat pump support beyond buildings and supports electrification of low- and medium-temperature heat.
India	Phase I of the National Bioenergy Programme, which ran to March 2026, supported pellet and briquette manufacturing, non-bagasse cogeneration, waste-to-energy from industrial and agricultural residues, and biogas for thermal and cooling use. The GOBARdhan scheme, approved in August 2026, extends compressed-biogas support to FY 2035-36.	**Supportive, with continuity restored.** Phase I strengthened biomass supply chains and biogas for heat through March 2026; GOBARdhan sustains renewable gas support thereafter.
European Union	The Innovation Fund's first Heat Auction selected 65 projects across ten EU countries for nearly EUR 400 million; a second EUR 1-billion round is due to open in December 2026. The auction serves as a pilot for the future Industrial Decarbonisation Bank.	**Strengthening.** Competitive support should accelerate heat pump, electric boiler and solar thermal uptake across several industry sectors.
United States	The Department of Energy cancelled more than half of the projects selected under the USD 6.3-billion Industrial Demonstrations Program, including heat pumps, electric boilers and thermal storage.	**Weakening federally.** Deployment relies increasingly on commercial projects, tailored tariffs and state action.
Brazil	The Fuel of the Future Law creates annual emissions-reduction targets for natural gas suppliers, met through biomethane purchases or certificates; the first target is 0.5% in 2026, and the law allows future targets of up to 10%.	**Strengthening.** Creates a new demand signal for biomethane, including in gas-using industry.

Note: "Direction" refers to changes in overall policy stance since the publication of *Renewables 2025*.

Renewable heat growth in other regions reflects local resource availability and industrial structures. Brazil maintains the highest renewable share in industrial heat globally, supported by bagasse and black liquor from the sugar, ethanol and pulp and paper industries. Agricultural residues drive growth across Southeast Asia and sub-Saharan Africa, while renewable heat consumption in the

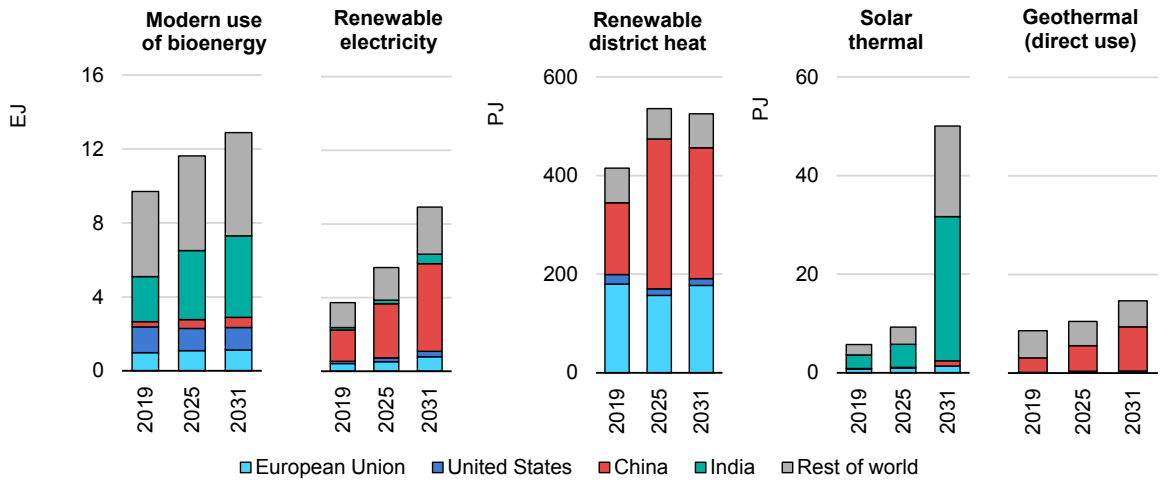
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Middle East more than doubles from a low base. In Japan, Korea, Australia and New Zealand, growth is spurred primarily by renewable electricity used for heat.

Technology trends to 2031

Electrification is increasingly driving renewable heat growth in industry, but bioenergy remains the largest source. While modern bioenergy accounted for 65% of renewable industrial heat consumption in 2025, growth is slowing compared with 2019-2025, reflecting its concentration in industries with access to on-site residues. By contrast, renewable electricity leads the increase in modern renewables, rising almost 60% to 2031 and providing around 70% of renewable heat expansion. Solar thermal and geothermal develop quickly but continue to account for only a small share of industrial renewable heat.

Renewable heat consumption in industry by technology, 2025-2031



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Source: IEA (forthcoming), World Energy Outlook 2026.

Technology options for renewable industrial heat vary significantly by temperature level. Heat pumps, electric boilers and solar thermal and geothermal technologies are commercially available for low-temperature applications including food and beverage production, textile manufacturing and drying processes, while large-scale industrial heat pumps are well established for applications requiring up to around 150°C. At higher temperatures, particularly above 350°C, renewable energy alternatives remain more limited, with solid biomass and biogases currently the most mature options. Hydrogen is expected to play only a limited role over the outlook period due to its high costs and concentration in specific feedstock and high-temperature applications. The following sections assess the outlook for each technology, focusing on markets, costs and policy developments.

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Modern bioenergy remains the backbone of industrial renewable heat, anchored in by-product economics

Coming mainly from agro-industrial and pulp and paper by-products, modern bioenergy continues to be the largest source of renewable heat in industry. While liquid biofuel and biogas consumption increases over the outlook period, solid biomass continues to account for more than 98% of modern bioenergy use for industrial heat. Consumption rises from 11.6 EJ in 2025 to 12.9 EJ in 2031, concentrated in sectors where residues such as black liquor, bagasse and other biomass by-products are generated on site.

In addition, anaerobic digestion of organic process residues and wastewater produces biogas for on-site process heat, steam or combined heat and power. In these applications, bioenergy is less a fuel-switching option than a way to use process residues that would otherwise require disposal, helping explain high renewable heat shares in Brazil and India. Biomethane injected into gas grids can also supply industrial heat, for instance in markets covered by emissions trading systems such as the EU ETS.

Growth to 2031 is concentrated in emerging and developing economies. India adds 0.7 EJ, with Southeast Asia, sub-Saharan Africa and Brazil contributing most of the remaining growth, while consumption in the European Union and the United States is broadly flat as sustainable feedstock competition from transport biofuels and power generation caps expansion. Growth beyond on-site residues depends increasingly on well-organised supply chains – for pellets, briquettes and biomethane. India provides central financial assistance for pellet and briquette manufacturing, Brazil's biomethane mandate starts in 2026, and in the European Union the Renewable Energy Directive III sets an indicative target for renewable energy use in industry to rise by 1.6 percentage points per year, which biomethane can help meet through existing gas infrastructure.

Sustainable feedstock availability, rather than technology maturity, remains the main constraint. Biomass boilers are commercially mature across a wide range of industrial temperature needs, but residues are finite and additional feedstock mobilisation raises logistics costs and sustainability requirements. As a result, bioenergy remains the largest source of renewable industrial heat to 2031, but its share falls from 65% in 2025 to 58% as electrification becomes the main source of growth**.**

Electrification is becoming the main driver of renewable industrial heat growth

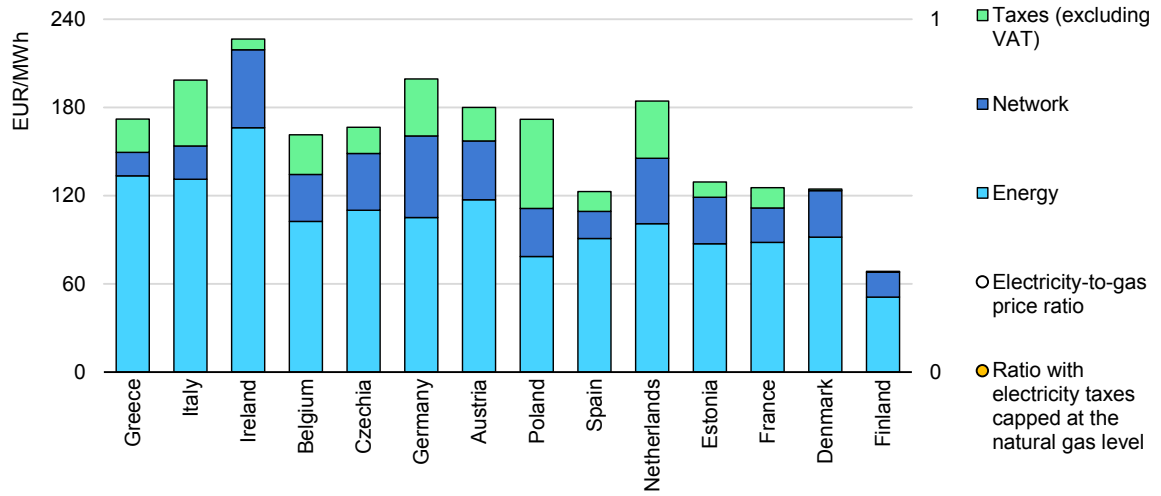
The amount of renewable electricity used for industrial heat increases almost 60%, from 5.6 EJ in 2025 to 8.9 EJ in 2031, providing around 70% of all renewable heat growth in industry. Faster electrification and power sector

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decarbonisation underpin this expansion. As industry adopts more electric heating technologies, the renewable share of electricity used for heat rises from 35% to around 45%, reinforcing renewable heat deployment. Established technologies such as electric arc furnaces, resistance heaters and induction systems continue to dominate, while heat pumps and electric boilers expand the potential for renewable steam production.

The relative cost of electricity and fossil fuels is increasingly determining the pace of industrial electrification. In markets where electricity remains significantly more expensive than gas, the competitiveness of electric heat technologies is lower, slowing renewable heat uptake despite continued technology improvements. As a result, policy support is increasingly targeting operating costs rather than technology deployment alone. In the European Union, the Innovation Fund Heat Auction supports projects based on the cost of emissions reductions, while in China direct connections to captive renewable power plants can nearly halve the cost of electrified steam.

Industrial natural gas and electricity retail prices in selected EU countries, 2025



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Notes: Prices apply to industrial consumers in annual consumption bands of 2 000-20 000 MWh for electricity and 10 000-99 999 GJ for natural gas. VAT is excluded from the tax component because it is generally recoverable. The adjusted electricity-to-natural-gas price ratio replaces the electricity tax component with the natural gas tax component, on an energy-equivalent basis, only where natural gas taxes are lower. Where electricity taxes are already lower, the observed electricity tax component is retained. All other price components remain unchanged.

Source: IEA analysis based on electricity and natural gas price data from Eurostat, (accessed July 2026).

Narrowing the electricity-to-gas price gap could significantly accelerate industrial electrification across the European Union. The Electrification Action Plan, published in July 2026, makes the gap an explicit policy target for the first time: member states should reduce industrial electricity-to-gas price ratios to at most 2.0 by 2030 and tax electricity no more heavily than gas. The starting point

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is within reach for many, as industrial electricity costs no more than three times as much as natural gas in 19 of the 25 member states with data for both fuels, with a median ratio of 2.6.

Finland and Sweden are at the favourable extreme. They have the European Union's most affordable industrial electricity, taxed at less than EUR 1/MWh, as well as small, heavily taxed gas markets, making electricity cheaper than gas per unit of energy (ratios of 0.7-0.8). Thus, electric boilers undercut gas boilers on running costs even before heat pump efficiency gains are considered.

Elsewhere, taxation still tilts the field against electrification. Poland's case is the starkest: taxes and levies add over EUR 60/MWh to industrial electricity costs but less than EUR 1/MWh to gas, the widest gap in the European Union. Implementing the plan's tax-parity recommendation alone would lower Poland's ratio from 2.6 to 1.7, the third-lowest in the European Union, and would put Belgium, Italy and Romania (which have observed ratios of 3.1-3.4) below the 3:1 mark, closer to the 2030 benchmark.

Thermal energy storage strengthens the case for industrial electrification with renewables

Thermal energy storage is advancing, with deployment now expanding from early commercial projects and larger demonstrations. Heat batteries use contracted or on-site renewable electricity to produce continuous heat and steam, helping industrial facilities cost-effectively match variable renewable generation to steady process demand. Rondo Energy's 100-MWh heat battery entered into commercial operation at a California oil production site in October 2025, charged exclusively by an on-site solar array. In May 2026, Antora Energy began commissioning a 5-GWh thermal storage system adjacent to POET's bioethanol plant in South Dakota, supported by a tailored electricity tariff developed with Otter Tail Power and approved by the state regulator. Meanwhile, Kyoto Group's 56-MWh molten-salt unit began operation at an industrial site in Hungary.

The economics of thermal storage depend as much on electricity pricing as on technology performance. Storage systems create the most value when they can charge during periods of low electricity prices and discharge heat when demand is high. As a result, access to low-cost renewable electricity, wholesale markets and time-varying tariffs is becoming a key determinant of project competitiveness.

Policy and market design are therefore emerging as critical enablers of deployment. In Europe, access to wholesale electricity markets and periods of abundant renewable generation are improving the economics of thermal storage projects. In many other markets, flat industrial electricity tariffs limit opportunities

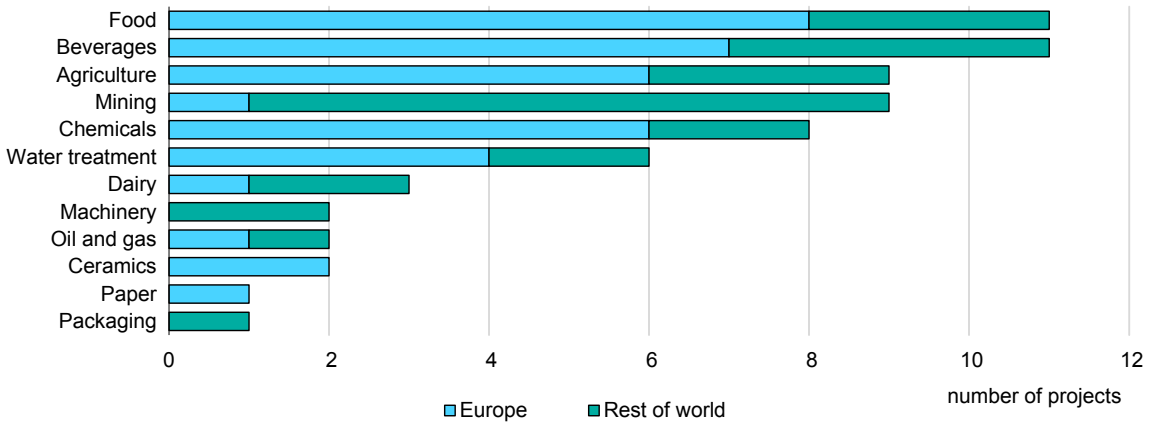
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to capture low-cost power and reduce the value of storage. In our outlook, thermal energy storage is reflected within electricity used for heat rather than as a separate technology. It supports higher shares of industrial electrification by aligning heat demand with periods of abundant renewable electricity.

Solar thermal remains a niche technology but shows the fastest growth of any renewable heat source in industry

Consumption increases from 9 PJ in 2025 to 50 PJ in 2031, accounting for less than 1% of renewable industrial heat but recording the highest growth rate of any renewable heat technology. India provides over half of the increase, followed by the Middle East, supported by favourable solar resources and growing demand for low- and medium-temperature process heat. The global fleet numbered around 1 300 plants (900 MWth) by the end of 2025, indicating substantial untapped potential for growth as policy support, financing models and project economics continue to improve.

Announced solar heat for industrial process projects by sector and region



Source: Reproduced from Solar Thermal World (2026), Solar Industrial Heat Outlook 2026-2028.

The market is shifting towards larger-scale and higher-temperature applications. Concentrating solar collectors, including parabolic trough systems, made up around two-thirds of new capacity additions in 2024, reflecting growing demand for process heat in the 100-400°C range. At the same time, heat-as-a-service business models are becoming more common, reducing upfront investment requirements and transferring performance risk away from industrial customers.

Recent projects have been commissioned in Australia, France, India, Morocco, Spain, Türkiye and the United States, with most applications concentrated in the food, beverage and pharmaceutical industries where solar technologies are well suited to meet low- and medium-temperature heat needs. In Europe, solar thermal

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projects were among the winners of the first Innovation Fund Heat Auction – an early signal that auction-based support can reach direct renewable heat as well as electrification.

Geothermal use in industry remains limited, but new technologies could unlock wider industrial applications

Geothermal energy provides only a small share of renewable industrial heat despite abundant resource potential. Consumption rises from 10 PJ in 2025 to 15 PJ in 2031, accounting for well below 1% of renewable heat demand in industry. Deployment remains concentrated in a handful of markets, led by China and supplemented by Australia and New Zealand, where favourable resource availability coincides with high industrial heat demand. Conventional geothermal resources are highly site-specific and often located far from industrial demand centres, restricting development to industries that can access local resources directly. As a result, geothermal deployment remains largely confined to niche applications such as food processing, drying and washing processes.

Next-generation geothermal technologies could expand long-term opportunities. Enhanced geothermal systems and closed-loop technologies aim to make geothermal heat accessible in a wider range of locations, while advances in drilling techniques are helping reduce costs. However, their impact on industrial heat deployment is expected to remain limited within the outlook period. Near-term opportunities are likely to be centred on district heating, with industrial applications emerging after 2030.

Agriculture

Outlook summary

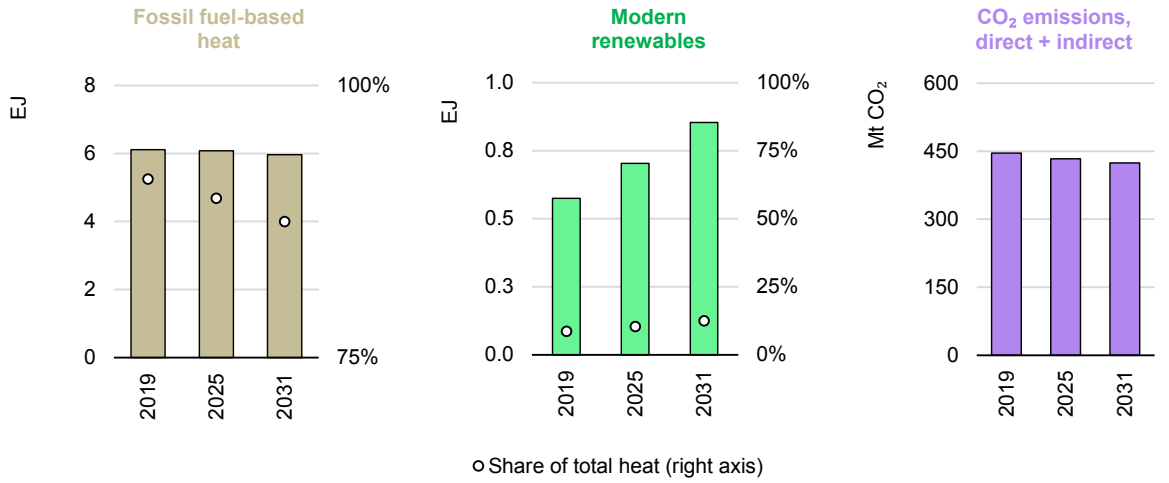
Modern renewable heat consumption in agriculture increases 21% between 2025 and 2031. Renewables meet 13% of agricultural heat demand by 2031, up from 10% in 2025. Bioenergy fuels around three-quarters of the increase, while solar thermal and geothermal make smaller but growing contributions.

Renewable energy growth only partially displaces fossil fuels. Fossil fuel consumption declines just 2% over the outlook period as total agricultural heat demand remains broadly stable. Despite continued renewable energy deployment, fossil fuels still meet almost 90% of agricultural heat demand in 2031.

Heat-related CO_2 emissions decline a modest 2% between 2025 and 2031. This pace, similar to that of 2019-2025, remains slow because fossil fuels continue to dominate the sector's heat production.

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Renewable and fossil heat consumption in agriculture, shares of renewables in heat demand, and total CO_2 emissions related to heat, 2019-2031



IEA. CC BY 4.0.

Source: IEA (forthcoming), World Energy Outlook 2026.

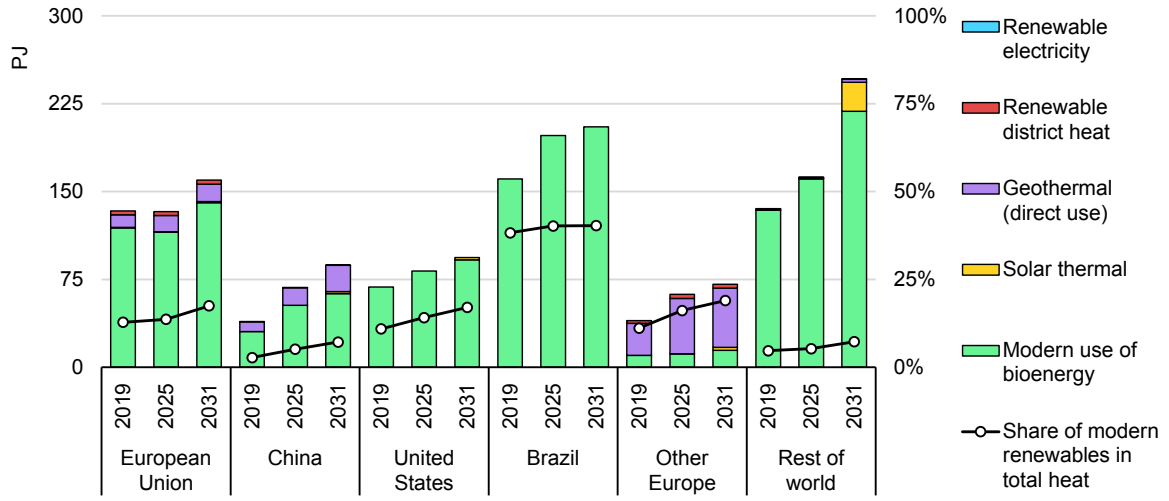
Renewable heat growth in agriculture is geographically dispersed. The European Union and sub-Saharan Africa account for the largest additions to 2031, followed by China (+19 PJ), Japan (+12 PJ) and the United States (+11 PJ). Brazil remains the largest market, although its renewable heat share stays broadly unchanged as heat demand continues to grow.

Modern bioenergy remains the backbone of renewable energy consumption for agricultural heat. It supplies 86% in 2031 and around three-quarters of global growth. The largest additions are in sub-Saharan Africa (+24 PJ) and the European Union (+25 PJ). Bioenergy also provides all of Brazil's increase and most of the growth in the United States and Japan.

Solar thermal is the main source of diversification. Consumption rises from less than 1 PJ in 2025 to 32 PJ in 2031, led by the Middle East. Solar energy systems can be used for crop drying, greenhouse heating and hot water production on farms. Direct geothermal use also expands, with more than half of the increase in China, particularly for greenhouse and aquaculture applications where suitable resources are available.

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Renewable heat consumption in agriculture and shares of renewables in heat demand in selected regions, 2019-2031



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Source: IEA (forthcoming), World Energy Outlook 2026.

Renewable heat deployment in agriculture remains closely linked to local resource availability and specific end-use needs. Most growth occurs in applications such as greenhouse heating, crop and grain drying, aquaculture and livestock production, for which renewable heat technologies can be integrated directly into on-site operations.

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Chapter 4. Biogases

Summary

- Global production of biogases (biogas and biomethane) reached 1 785 PJ in 2025 and rises 18% by 2031 in the main case. Biomethane production is set to almost double by 2031, and biogas falls slightly (2%) due to competition from other renewables and, in some cases, upgrading to biomethane production.
- This year's global forecast is revised downwards 12% to reflect updates to the IEA model for computing India's biogas production, and weaker-than-expected growth in Europe and the United States.
- Sustainable waste and residue technical potential is estimated at above 810 bcme (around 29 000 PJ) annually, but feedstock supply chains remain one of the main constraints to faster development.
- Europe remains the largest biogas market, accounting for 44% of global production in 2025. EU biogas and biomethane production is forecast to grow 18% by 2031 to 14 bcme (505 PJ) and over 8 bcme (300 PJ) respectively, remaining below the REPowerEU target of 35 bcm by 2030.
- Biomethane growth in the United States is expected to slow after rapid expansion since 2022, as it already accounts for 94% of natural gas use in gas-fuelled vehicle fleets. Combined biogas and biomethane production is projected to grow just 6% by 2031, after expanding 29% in 2019-2025.
- Large emerging economies accelerate biomethane supply, with India's output rising almost ninefold by 2031. China, India and Brazil are developing support policies, but gas infrastructure and feedstock supply chains remain constraints.
- Transport remains the main biomethane market in mature systems in 2031, with growth slowing in the United States and Europe and accelerating in India.
- Clearer guidance for certificates under development in voluntary markets, together with fully operational cross-border certificate trading in the European Union, is expected to strengthen heat demand from utilities and industrial buyers.
- Biomethane is emerging as a maritime fuel, supported by FuelEU Maritime, ETS2 and the growing LNG-fuelled vessel fleet, while also attracting interest as a feedstock for low-emissions hydrogen and methanol.
- Energy security is strengthening the case for domestic biogases, with current production reducing France and Germany's natural gas import dependence by around 8-10 percentage points.

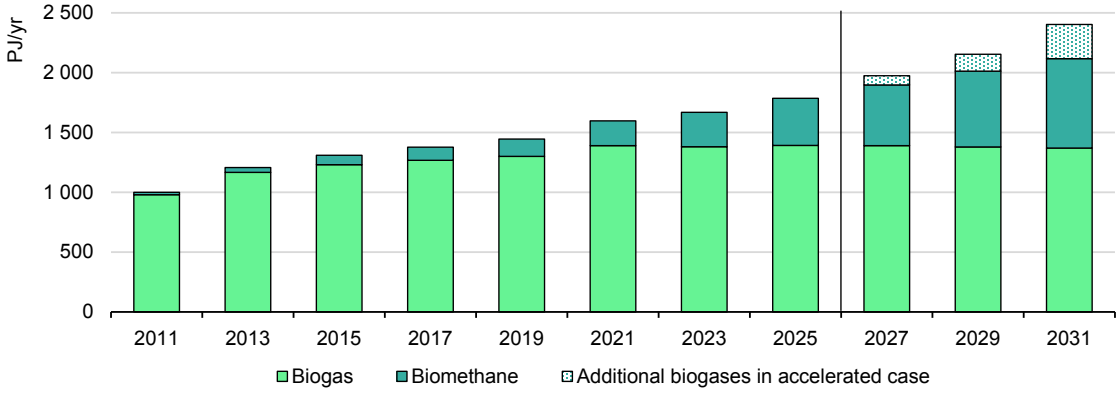
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Global overview

Production of biogases continues to expand, backed by a widening range of regulatory frameworks and their introduction in a growing number of countries. Policy support aims to meet the key objectives of 1) enhancing energy security by providing a domestic energy source that diversifies supply and reduces fuel import dependence; 2) decarbonising the energy system, particularly in hard-to-abate sectors; 3) mitigating methane emissions from livestock and organic waste; 4) fostering rural economic development; and 5) improving waste management practices.

Global production of biogases (both biogas and its purified stream, biomethane) reached 1 785 PJ in 2025, of which 78% was biogas. Production continues to increase in most countries/regions, with global output forecast to grow 18% over 2026-2031 in the main case and 35% in the accelerated case.

Global historical and forecast production of biogases, main and accelerated cases



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Biomethane production drives this growth, with output projected to almost double between 2025 and 2031. Its compatibility with existing natural gas infrastructure and end-use equipment supports a wider range of applications, including heating in buildings and industry, as well as road and maritime transport. In contrast, biogas production – used mainly for electricity generation, combined heat and power production and on-site applications in industry – is expected to fall 2% over the forecast period.

The progressive decline in biogas use for power generation in mature markets reflects increasing competition from other renewable power technologies. Available organic industrial waste and wastewater sludge is utilised to a large degree in mature markets, although its use is also expanding in emerging ones. Finally, the upgrading of some biogas plants to produce biomethane also contributes to a decrease in the production of biogas as a final product.

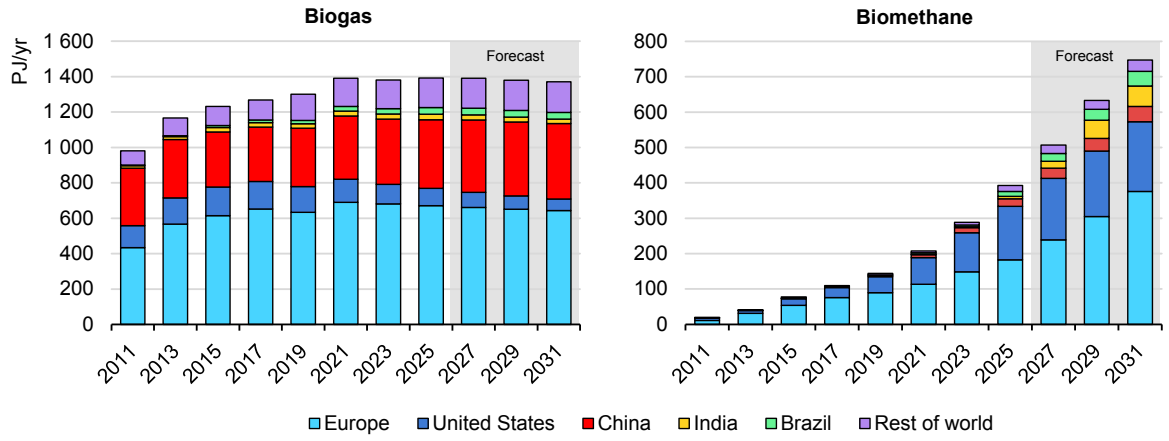
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In 2025, the European Union accounted for nearly 38% of global biogas and biomethane production, and this share rises to 44% when the United Kingdom is included. For biomethane alone, EU production represented 38% of global output, and the United States was responsible for an additional 38%.

The cases of China and India illustrate the time required for biomethane markets to develop. Although both countries began introducing dedicated support policies in 2017 and 2018, market growth remained limited for several years. However, recent production trends indicate that the sector has expanded beyond initial development and is showing meaningful market growth, with biomethane production projected to increase almost ninefold in India by 2031 and to double in China.

Elsewhere, including in Brazil and Canada, governments are now beginning to put comparable policy frameworks in place. While these markets are at an earlier stage of development and their growth trajectory remains more uncertain, biomethane production is nevertheless projected to more than double by 2031.

Historical production of biogas and biomethane (2011-2025) and forecast to 2031 by region, main case



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Note: Europe includes all EU countries plus Belarus, Bosnia and Herzegovina, Iceland, Moldova, North Macedonia, Norway, Serbia, Switzerland, Türkiye, the United Kingdom and Ukraine.

Forecast revised downwards

We have revised both the 2025 baseline and the forecast downwards since last year. Global production of biogases is now projected to grow 16% over 2025-2030, compared with the 22% growth previously projected.

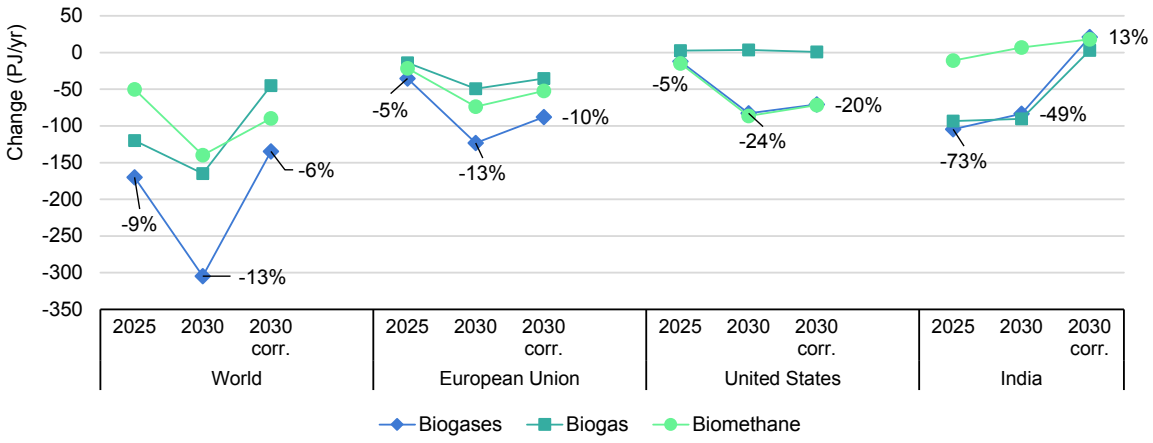
The main revision affecting both the baseline and the outlook is the update to the IEA model for India. It involves a reassessment of operational small-scale household biogas plants and their associated biogas production, as well as the

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incorporation of new data on the biomethane project pipeline from the updated Gobardhan central registry. Together, these changes reduce India's 2025 baseline by 73%, primarily due to lower biogas output. At the same time, the expanded biomethane project pipeline results in stronger projected growth over the forecast period as more plants come online. Overall, India's projected 2030 production of biogases is now 49% lower than in last year's forecast.

We have also revised EU's forecast downwards, partly reflecting lower-than-expected production in 2025. Several countries, including the largest market, Germany, reported significantly weaker growth between 2024 and 2025 than anticipated based on previous years' growth, particularly for biogas. After several years of stagnation, biogas production is now showing signs of structural decline, reflected in the updated forecast. For biomethane, the 2025 baseline has been revised downwards slightly following lower reported production, resulting in a more moderate trajectory to 2030. Overall, these revisions reduce projected 2030 EU biogas and biomethane production by 14% compared with last year's forecast.

Changes to baseline values and 2030 forecast from *Renewables 2025* to *Renewables 2026*



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Notes: "2030 corr." indicates corrections to the 2030 forecast after removing the effect of revisions to the 2025 baseline. Labels (%) show the percentage change relative to the previous edition's projected production of biogases.

Main trends and challenges

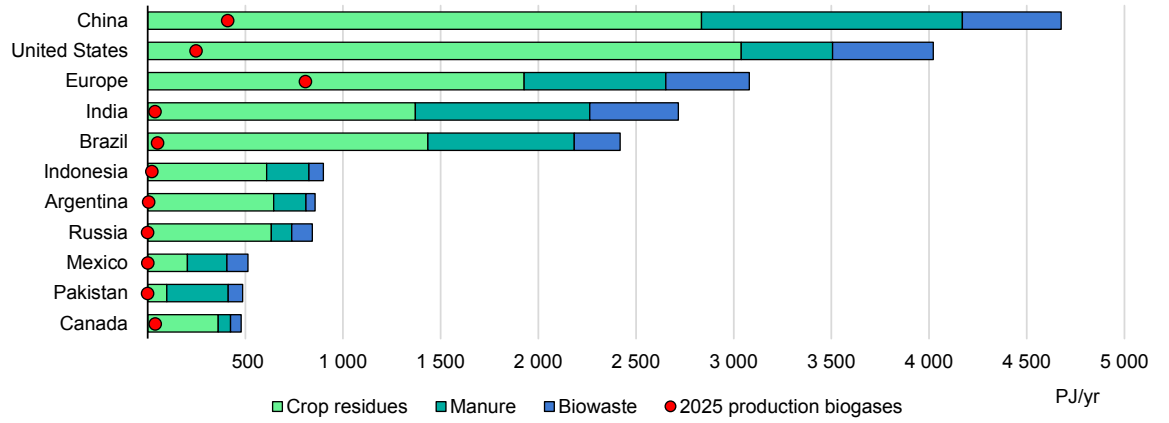
Growth in several mature markets is slowing down after years of record-level expansion. In Germany and Denmark, ongoing regulatory changes have created uncertainty and are weighing on investment in new projects. In the United States, growth is shifting from transport towards thermal applications, which typically offer less predictable revenue streams. This slowdown in mature markets is partly offset by growth in some emerging markets, including large new markets (e.g. India, China and Brazil) as well as smaller ones in a number of European countries and in Southeast Asia.

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Developing efficient feedstock supply chains at scale remains a key challenge to accelerate biogas and biomethane market growth. Recent IEA geospatial analysis finds that waste and residues could sustainably produce more than 810 bcme[15] (around 29 EJ) of biogases annually – enough to meet almost 20% of global natural gas demand in 2024. While feedstock availability is substantial, unlocking this potential requires supply chains for feedstock collection, aggregation and storage at scale, the development of stable feedstock markets and closer integration of biogas and biomethane production with agricultural activities.

Managing and valorising digestate, the main co-product of anaerobic digestion, also remains a critical challenge. Technology development is focused on reducing production costs by improving processability and increasing yields from cellulosic materials, and by standardising plant designs. At the same time, project developers are pursuing economies of scale by constructing larger, more efficient plants.

Waste and residue feedstock potential to produce biogases, and production in 2025 for selected countries



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Note: Europe includes all EU countries plus Belarus, Bosnia and Herzegovina, Iceland, Moldova, North Macedonia, Norway, Serbia, Switzerland, Türkiye, the United Kingdom and Ukraine.

Sources: IEA (2026), Interactive Map of Global Biogas and Biomethane Potential, (accessed 23 September 2026); IEA (2025), Renewables 2025.

Over the forecast period, slower growth in demand for biomethane is expected in the transport sector. Meanwhile, consumption for thermal applications rises. At the same time, new uses may emerge, including bio-LNG for maritime shipping, biomethane as a raw material for chemical reactions, or the capture of biogenic CO_2 from anaerobic digesters for permanent storage, synthetic fuel production or other industrial uses.

[15] Billion cubic metre equivalent, an energy unit applicable to different types of gases. In this text, bcme is equivalent to 36 PJ, based on the net calorific value of natural gas.

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On the regulatory side, Europe is working to improve its accounting framework and address fragmentation across certificate markets, as different regulatory instruments (RED III, ETS1 and ETS2, CBAM and national mandates) currently rely on various certificate systems and requirements.

The planned revision and inclusion of biomethane for voluntary use in industry under the global GHG Protocol, expected to be finalised in 2028 with possibly some interim guidance in 2027, will likely foster demand from voluntary buyers through biomethane purchase agreements (BPAs). For the moment, the use of biomethane certificates remains subject to regulatory and methodological uncertainties. The GHG Protocol is a key reference framework for corporate accounting and strongly influences the development of voluntary markets, with other initiatives such as the Science Based Targets initiative (SBTi) aligning with its principles. Current protocol guidance does not recognise book-and-claim systems or the use of biomethane sourced from a shared gas grid for Scope 1 emissions reporting. The ongoing GHG Protocol review of market-based instruments could therefore have important implications for the future treatment of biomethane certificates.

Although policy momentum was established in previous years and no new major legislation or regulation specifically targeting biogases has been released since the beginning of the current conflict in the Middle East, the related disruption in global natural gas trading has reinforced the energy-security rationale for biogases. In the European Union, the April 2026 AccelerateEU communication explicitly recognises biogas and biomethane as strategic substitutes for imported fossil fuels, particularly in hard-to-electrify sectors.

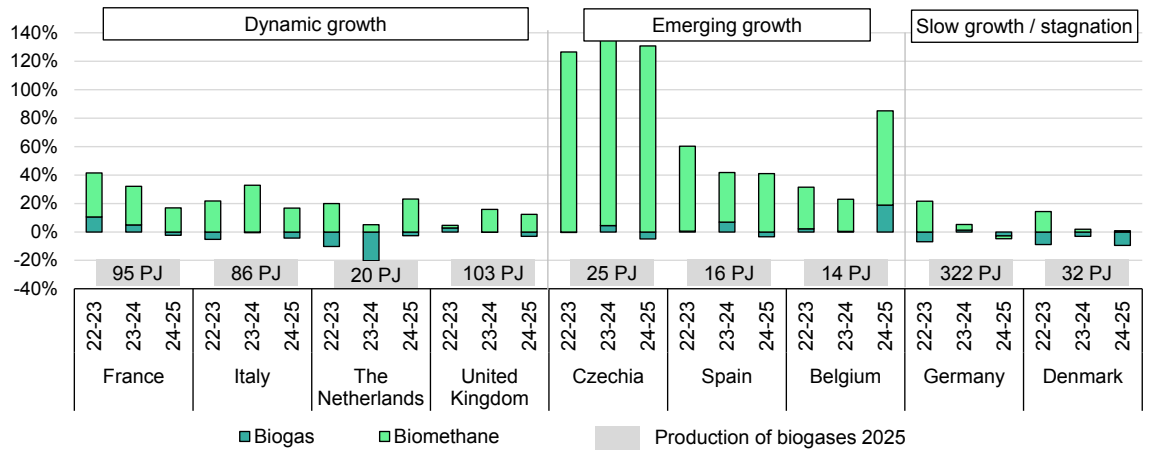
Regional analysis: Production trends, regulatory outlook and forecast

Europe

In the period 2020-2025, EU biomethane production increased 19% per year on average, reaching 4.2 bcme (151 PJ) in 2025, while biogas has remained broadly stable at just below 15 bcme (534 PJ). The United Kingdom adds 2 bcme (75 PJ) of biogas and 0.8 bcme (28 PJ) of biomethane to production in the European region. Several EU countries incorporated biogas and biomethane targets into their National Energy and Climate Plans (NECPs), providing greater long-term visibility for market development. Overall, market dynamics vary considerably among countries, with growth falling into three main categories: dynamic; emerging; and slow/stagnating.

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Year-on-year biogas and biomethane production growth 2022-2025, and 2025 production of biogases in selected European countries



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Mature markets with plateaued growth

After two years of slow or even negative growth (for biogas), Germany and Denmark appear to have reached a plateau. **Germany**, the largest market for biogases in the European Union, has not set a national target for biomethane production in its final updated NECP, continuing the political uncertainty in the sector. Transport quota prices have dropped since 2023, following market distortions due to alleged cases of liquid biofuel fraud, although RED III transpositions and national regulation changes under discussion could help restore price stability.

The main growth drivers over the forecast period are the EU Emissions Trading System (ETS) and the German Emissions Trading Act (BEHG), and compliance with voluntary targets. Germany is also seeking to tackle sustainability aspects concerning its feedstocks, particularly by limiting the use of maize, which accounted for almost half of its biomethane production on an energy basis. Currently, the cap on maize and grain use is only applied to Renewable Energy Sources Act (EGG)-supported biogas plants generating electricity.

After several years of annual biomethane growth of around 15%, production in **Denmark** has effectively stalled since 2024. Ongoing discussions of regulatory revisions, including a proposed exemption from CO_2 taxes, and a weakened framework for feed-in tariffs, have limited new investment. Nevertheless, clear national targets to achieve 100% green gas consumption by 2030, combined with the highest level of announced investment in new biomethane projects in Europe, provide a positive outlook for sector recovery.

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Strong dynamic markets

France and Italy have led Europe's biomethane growth over the past six years, with production increasing elevenfold and eightfold respectively. They are expected to continue expanding strongly, although more slowly, with production set to double in France and triple in Italy by 2031.

France's introduction of obligations for gas suppliers to surrender injected biomethane certificates proportional to their gas sales, starting in 2026, marks a shift towards demand-driven support and is expected to strengthen investment signals. The obligation can be met by producing biomethane or by buying biogas production certificates (CPBs) from producers. Although the mechanism is still in its early stages, the growing project pipeline suggests it is strengthening market confidence.

In **Italy**, biomethane use has historically focused on transport, supported by a 2018 ministerial decree exclusively incentivising this use, but eligibility expanded to other applications in 2022, and demand is expected to diversify towards industrial heating. Italy also has Europe's largest biomethane project pipeline, with 23 TWh/yr (83 PJ/yr) of additional capacity planned.

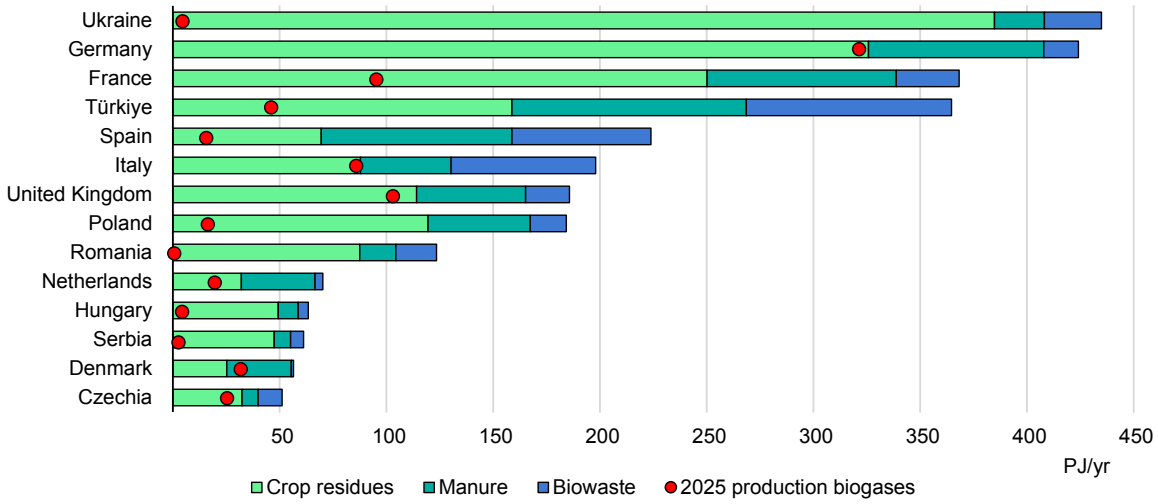
Another country in this group is the **United Kingdom**, a mature market that experienced stagnation in previous years but reported biomethane growth of more than 12% in both 2024 and 2025. The extension of the Green Gas Support Scheme (GGSS) – the main support for new biomethane plants – to 2028 has helped attract new investment, despite uncertainty over the sector's long-term policy framework. The introduction of a national biomethane target and the recognition of grid-injected biomethane under the UK ETS would further spur demand from the industrial sector.

Emerging growing markets

A number of countries with ample feedstock potential and established biogas production for on-site use have recently entered a new wave of biomethane development, driven by Russia's invasion of Ukraine and subsequent efforts in Europe to reduce reliance on Russian gas. In the past three years, Belgium, Spain and the Czech Republic have registered a notable take-off. The European Biogas Association (EBA) has identified announced investments corresponding to an additional 8.5 TWh/yr (30.6 PJ/yr) of capacity in Spain, underlining positive sector prospects within a policy framework that is still developing.

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Waste and residue feedstock potential to produce biogases and 2025 production in selected European countries



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Source: IEA (2026), Interactive Map of Global Biogas and Biomethane Potential, (accessed 23 September 2026).

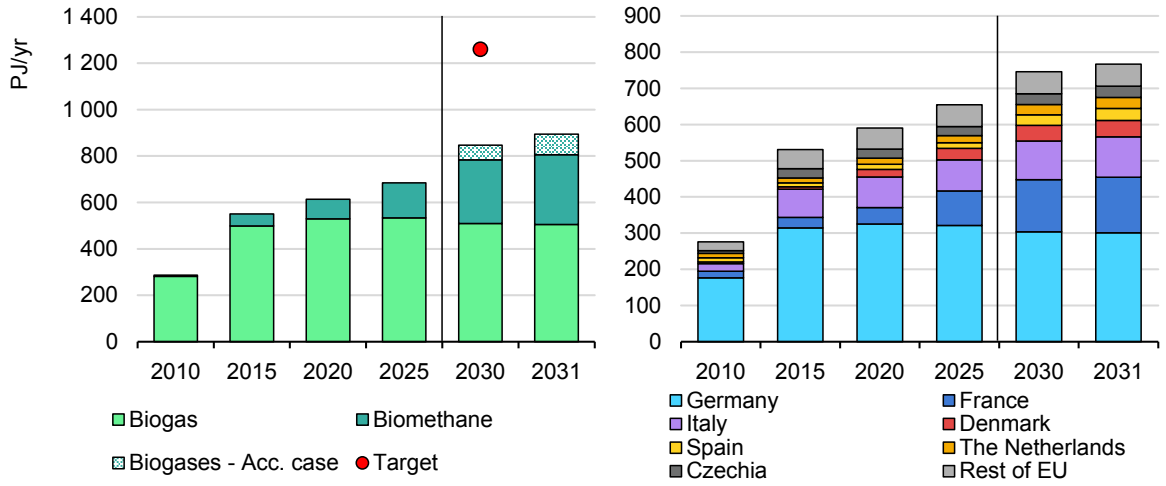
Forecast

EU biogas and biomethane production is forecast to exceed 780 PJ/yr by 2030, corresponding to around 62% of the REPowerEU target of 35 bcm of biomethane by 2030, if biogas and biomethane are considered together as per the European Commission's revised REPowerEU tracking. Growth is expected to continue as the sector develops in more emerging European countries, given that feedstock potential remains largely untapped in most of them.

However, our forecast indicates that the EU goal would be achieved with some delay under current policies, market developments and challenges. Given the slowdown observed in several of the largest markets in 2024 and 2025, a sharp acceleration would be required through 2030. Even under the accelerated case, production is expected to reach only 67% of the RePowerEU target. To help narrow the gap, the European Union is developing a regulatory framework to enable biomethane imports from Ukraine, which has the region's largest feedstock potential and is well connected through existing gas transmission and storage infrastructure.

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EU biogas and biomethane historical and forecast production per type of gas (left) and per country (right)



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Note: Acc. case = accelerated case. Rest of EU = rest of European Union.

Regulatory changes

As biomethane markets mature, policy frameworks are gradually shifting from supply-side support mechanisms, such as feed-in tariffs, premiums and tenders, towards demand-side measures that create market-based revenue streams based on certificates. Under these mechanisms, the cost is passed on to final users, reducing reliance on public expenditures.

Several countries, including **France**, **Portugal** and **Latvia** have introduced biomethane or renewable gas blending mandates for gas suppliers, while the Netherlands, Ireland and Spain have announced plans for them. Additionally, all EU member states are implementing progressively rising renewable fuel targets in transport that can be met through biomethane use as RED III gets transposed into national legislation. Some countries are choosing to shift to emission reduction targets for transport, which historically favour the use of biomethane, especially biomethane with lower carbon intensity (for instance, from animal manure).

In parallel, the recognition of biomethane under the EU ETS in each country and the inclusion of biomethane guidance in the GHG Protocol for voluntary corporate targets are expected to support the emergence of BPAs between connected producers and industrial consumers.

However, supply-side incentives remain relevant in many markets such as Italy, Denmark, the Netherlands and the United Kingdom, and are available for small plants in France. They have been proven effective in providing the long-term revenue certainty needed to unlock investment, especially in emerging markets.

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EU biogas/biomethane sector main policies and regulations

Policy	Year	Key information	Targets
EU Emissions Trading System (EU ETS)	2005, revised in 2023	Establishes a cap-and-trade carbon market covering emissions from electricity and heat generation, some industrial sectors, aviation and –since 2024 – maritime transport.	62% emissions reduction by 2030 from 2005 levels.
Waste Framework Directive (WFD) amendment 2018/851	2018 amendment	Sets an obligation to collect organic waste separately since 2024, improving the quantity and quality of feedstocks available for composting and anaerobic digestion.	
Renewable Energy Directive II (RED II) (2018/2001)	2018	Sets obligations for fuel suppliers to include a minimum share of renewable energy in transport. Biomethane is eligible for compliance. The directive imposes thresholds for minimum GHG reductions, and advanced fuels count double.	32% renewable energy share by 2030. Transport: 14%. Advanced biofuels and biogas: 3.5%.
REPowerEU plan (COM(2022)230)	2022	Aims to reduce fossil fuel import dependence. It sets a non-binding biomethane target for 2030.	35 bcm of biomethane by 2030
Monitoring and Reporting Regulation (MRR), 2018/2066, and revision 2023/2122	2018, revised in 2023	Allows biomass-derived fuels to be assigned a zero-emission factor under the EU ETS. Fuels must comply with sustainability and GHG-saving criteria under RED II and III. Since 2024, biomethane injected into grids, compliant with the Union Database (UDB) mass balance, can be used for the ETS.	
Renewable Energy Directive revision (RED III) (2023/2413)	2023	Sets more ambitious binding targets. When transposing to national laws, countries can choose between an energy-share target in transport or a GHG intensity reduction. Mass-balance traceability and chain-of-custody systems become mandatory. For the first time, it includes maritime shipping in transport, and explicitly broadens biomethane uses outside the transport sector. Permitting is improved.	42.5% renewable energy share by 2030. Transport: 29% energy share or 14.5% GHG intensity reduction. Advanced biofuels and renewable fuels of non-biological origin 5.5%.
EU Emissions Trading System 2 (ETS2)	2023 revision	Includes GHG emissions from buildings, road transport and small industry. Part of the Fit for 55 Package, it will be fully operational in 2028.	42% emissions reduction by 2030 compared to 2005.
FuelEU Maritime regulation, 2023/1805	2023	Establishes well-to-wake GHG emission intensity limits for energy used in ships calling at EU ports. It is technology neutral; fuels need to comply with RED sustainability criteria. Applicable from 2025.	Emissions reductions compared to 2020: -2% by 2025, -6% by 2030, -14.5% by 2035, -31% by 2040, -62% by 2045, -80% by 2050.

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Policy	Year	Key information	Targets
EU Gas Package (Directive 2024/1788 and Regulation 2024/1789)	2024	Establishes the regulatory framework for renewable gases, including biomethane and hydrogen. It improves planning and integration, and for biomethane reduces barriers to cross-border trading across the European Union.	
Clean Industrial Deal	2025	Promotes industrial competitiveness and increases demand for renewable energy in industry, including biomethane, through a strategic framework.	
European Commission Biomethane Mechanism	Jun 2026	Connects biomethane buyers and sellers through a voluntary tool to accelerate European market development and create business opportunities.	

Germany biogas/biomethane sector main policies and regulations

Policy	Year	Key information	Targets
Renewable Energy Sources Act (EEG)	2000	Initiates feed-in tariffs for renewable electricity production, including from biogases.	
	2017 amendment	Shifts to an auction system for plants >100 kW, requiring flexible operations.	
	2021 amendment	Includes specific tenders for biogases restricted to Southern Germany.	
	2025 amendment (biomass package)	Temporarily suspends the Southern restriction. It expands tender volumes for biogas, increases the flexibility bonus and adjusts flexibility requirements.	
Gas Grid Access Regulation (GasNZV)	2010	Sets the basic regulation regarding grid connection for biomethane plants.	
Federal Fuel Emissions Trading Act (BEHG)	2019	Establishes an emissions cap-and-trade and carbon pricing system in heating and transport from 2021.	
Building Energy Act (GEG)	2023 amendments	Makes biomethane eligible to meet renewable heating share targets in new buildings (65% in 2024, 100% by 2045).	Green gases rise from 15% by 2029 to 60% by 2040 in existing buildings.
Federal Emissions Control Act (BImSchG)	2021 amendment	Sets GHG reduction quotas in transport, to which biomethane can contribute.	8% reduction in 2023 and 25% in 2030 compared to fossil fuel values.
	2024 amendment	Quota transfers are suspended for 2025-2026 to help regulate quota prices.	

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Policy	Year	Key information	Targets
Climate contracts **state aid (1st round)**	2024	Provides EUR 4 billion state aid to support industry decarbonisation, allocated via competitive auctions. Aid is given through two-way carbon contracts for difference (CCfDs) to compensate for the additional cost of alternative fuels for 15 years.	
CHP Act	2025 amendment	Subsidies are extended for plants commissioned after 2026 and until 2030.	
Amendment **of the GHG reduction quota in the Federal Emissions Control Act**	Apr 2026	Amends the German GHG quota system implementing the transport-related provisions of RED III. It includes higher quotas for advanced biofuels, ends double counting for certain advanced biofuels, and from 2028 includes the possibility to credit electricity to EVs from biogas in the quota.	26.5% reduction in 2030 (from 25%), 2% advanced biofuels sub-quota (from 1%).
CO_2 Contracts for Difference state aid scheme (2nd round)	May 2026	Provides EUR 5 billion aid to decarbonise industrial processes, including the use of biomethane to replace fossil fuels. Projects are selected through a competitive bidding process based on aid per tonne of avoided CO_2. The aid will take the form of a two-way CCfD for 15 years.	
Building Modernisation Act (GMG)	July 2026	Replaces the GEG. It abolishes the previous technology-based bans and the 65% renewable energy share requirement for new heating systems. It sets rising decarbonisation targets (through bio-staircases) for new systems to include more bioenergy until full climate neutrality by 2045. It imposes a green-gas quota for energy distributors from 2028.	1% renewable gas by 2028. From 2029, 10% climate-neutral fuels in oil and gas heating systems.

France biogas/biomethane sector main policies and regulations

Policy	Year	Key information	Targets
Decree 2011-1597 and Ministerial Order of 23 November 2011	2011	Introduces the first feed-in tariffs for biomethane grid injection.	
Energy Transition for Green Growth Act (LTECV)	2015	Sets a goal of 10% biomethane in the grid by 2030.	10% of gas consumption from biomethane by 2030
Pluriannual Energy Programmes (PPE)	PPE 1 - 2016	Establishes the first national roadmap for renewable gases. It sets long-term targets for biogas and injected biomethane.	1.7 TWh injected biomethane by 2018, 8 TWh by 2023
	PPE 2 - 2020	Continues feed-in tariffs, introducing a trajectory for cost reductions. It sets a 14-TWh target of combined biogases by 2023, and 24-32 TWh by 2028.	6 TWh biomethane injected by 2023, 14-22 TWh by 2028
	PPE 3 - Feb 2026	Increases the ambition from previous PPE and confirms targets in final updated NECP.	44 TWh injected biomethane in 2030, 47-82 TWh biomethane in 2035

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Policy	Year	Key information	Targets
French Climate and Resilience Law and Order of 2 March 2022	2021, 2022	Reinforces the right to inject biomethane into the natural gas grid. It guarantees 60% connection cost supported by TSO/DSOs (capped at EUR 600 000). Introduces biogas production certificates.	
Decrees of 2020 **and** 2023	2020-2023	Establishes an auction scheme for new plants and conditions for purchase tariffs for biomethane grid injection. It maintains a feed-in tariff (FiT) for projects below 25 GWh HHV (FiT prices were revised in 2023).	
Tax on the Use of Renewable Energy in Transport (TIRUERT)	2023	Aligns taxation to GHG emission reductions in transport, at a penalty of EUR 100/t CO_2. Biomethane for transport is to be included from 2025.	
Final updated NECP	2024	Increases targets for biogases and injected biomethane to 2030.	50 TWh biogases by 2030, 44 TWh injected
Mandate for Biogas Production Certificates (CPBs) Decree 2024-718 **and Decree No. 2026-933**	2024, Sep 2026	Sets obligations for natural gas suppliers delivering to residential and commercial customers to submit biomethane CPBs to the state, with rising targets for additional production from 2026 (0.4%) to 2028 (4.2%). The non-compliance penalty is 100 EUR/MWh. Extended to the end of 2029 in 2026.	0.8 TWh in 2026, 3.1 TWh in 2027, 6.5 TWh in 2028
Third National Low-Carbon Strategy (SNBC 3)	Jul 2026	Sets long-term targets and decarbonisation pathways to 2050 through a legally binding strategy.	105 TWh HHV of biomethane by 2050
Incitation à la Réduction de l'Intensité Carbone des Carburants (IRICC)	Planned for 2027	Replaces TIRUERT. Transposes RED III and shifts to emission reduction targets for transport fuels, including shipping and LPG, aligned with RED III.	

Italy biogas/biomethane sector main policies and regulations

Policy	Year	Key information	Target
Ministerial Decree 2/3/2018	2018-2022	First dedicated support for biomethane; introduced incentives for biomethane used for transport only, for new plants entering into operation between 2018 and 2022 and for upgraded biogas plants. Fuel suppliers had to comply with blending obligations through certificates.	
National Recovery and Resilience Plan (PNRR) and Ministerial Decree 15/9/2022	2022-2028	Extends biomethane support to all final uses (excluding power generation). It introduces new up to 40% capital grants and production tariffs for grid injections for 15 years, allocated via tenders. Subsidies apply to new plants and biogas upgrading completed before June 2026 (later extended to 2028).	2.3 bcm production capacity by June 2026

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Policy	Year	Key information	Target
Ministerial Decree 224/2023	2023	Establishes a national guarantees-of-origin system for electricity, renewable gas and hydrogen to comply with the EU ETS in industrial sectors. It regulates BPAs for industry.	
National Integrated Energy and Climate Plan (PNIEC) 2023 and final updated 2024 NECP submission	2023, 2024	Sets a long-term biomethane target.	5.7 bcm/y by 2030
Decree-Law Bollette (Energy Bills Decree) No. 21/2026	Feb 2026	Clarifies treatment of biogas plants after current support schemes expire. Plants with electrical capacity larger than 300 kW will need to convert to biomethane production after 2030 to continue receiving public support. Smaller plants can continue producing electricity until 2037.	

UK biogas/biomethane sector main policies and regulations

Policy	Year	Key information	Target
Renewable Transport Fuel Obligation (RTFO) **Order**	2007	Specifies shares of renewables for fuel suppliers in the transport sector, verified through Renewable Transport Fuel Certificates (RTFCs).	14.6% volume by 2032
Non-domestic Renewable Heat Incentive (NDRHI)	2011-2021	Pays for kWh of eligible renewable heat, including from biogases, with tariffs varying by technology and scale, for businesses, public buildings, industry, district heating and multiple-residence buildings. For larger projects, the scheme introduces tariff guarantees.	
Domestic Renewable Heat Incentive (DRHI)	2014-2022	Awards 7-year feed-in tariffs for renewable heating installations in households.	
Resources and Waste Strategy **for England**	2018	Increases municipal recycling targets to 65%, with less than 10% waste going to landfills by 2035.	
Green Gas Support Scheme (GGSS) **and Green Gas Levy** (GGL)	2021-2028	Introduces financial incentives and 15-year feed-in tariffs for new plants injecting biomethane into the grid, extended to 2028. The biomethane must comply with Renewable Gas Guarantees of Origin (RGGOs). The GGL applies a tax to fossil fuel gas suppliers to fund the GGSS.	8 TWh biomethane generation by 2030 ambition
Green Gas Support Scheme (Amendment) **Regulations 2026**	Oct 2026	Extends GGSS commissioning deadline to March 2030.	
Simpler Recycling reforms under the Environment Act 2021	In force 2026	Mandates household separate food waste collection in England.	

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Biogas/biomethane sector main policies and regulations in other selected European countries

Policy	Year	Key information	Target
The Netherlands			
"Stimulering Duurzame Energie" (SDE++)	2020	Provides a sliding feed-in premium for renewable electricity production (including from biogas) and for green gases (including biomethane). The scheme compensates for the additional cost of reducing CO_2 emissions compared with the fossil-based alternatives.	
Fuel Transition Obligation	2026	Nationally transposes RED III. Previous tradeable renewable fuel units (HBEs) representing energy obligations are substituted for emission reduction units (EREs). Obligated parties are fuel suppliers to road transport, inland and maritime shipping and refining (EREs generated by the use of renewable fuels of non-biological origin in the production of fuels).	
Green gas blending obligation (BMV)	2026, proposed	Introduces an obligation for gas suppliers to reduce CO_2 by blending green gases or buying the corresponding certificates, starting in 2027. Obligated parties are users under the new ETS2 (buildings, small industry, small and medium-sized business, agriculture). Green certificates will be tradeable. The legislation is under parliamentary consideration.	Yearly reductions to 2.85 Mt CO_2-eq by 2031 (~1.1 bcm of green gas)
Denmark			
Renewable Energy Promotion Act No. 1392 of 2008	2008, amended 2019	Establishes support for non-purified biogas used for transport, industrial processes and heat.	
Gas Supply Act	2012, amended 2021	Establishes feed-in premiums for biomethane injected into the gas grid. In 2021, the possibility of introducing a competitive tendering mechanism for new biomethane production was included, although it has not been used yet.	
Green Gas Strategy	2021	Sets a roadmap for decarbonising gas consumption. It prioritises biogas and biomethane use in hard-to-electrify sectors.	70% green gas consumption by 2030, 100% by 2035
Agreement on a More Green and Secure Denmark	2022	Establishes the ambition for all gas consumed in Denmark to be green by 2030	100% green gas consumption by 2030
Portugal			
Renewable gases incorporation obligation, Decree-Law 30-A/2022	2022-2026	Obligates gas suppliers delivering above 2 000 GWh per year to incorporate at least 1% biomethane or renewable hydrogen into the volume of natural gas supplied. Compliance is demonstrated by cancelling the corresponding guarantees of origin. The obligation remains in force until 31 December 2026.	

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Policy	Year	Key information	Target
Spain			
Biogas Roadmap	2022	This first national strategy for biogas identifies 45 actions across regulation, financing, innovation and market development.	10.4 TWh/year of biogas production by 2030
Guarantees of Origin for Renewable Gases, Royal Decree 376/2022	2022	Creates the guarantees-of-origin system, providing the certification framework needed for voluntary biomethane trading.	
Recovery Plan Investment Aid, TED/706/2022	2022	Provides EUR 150 million in competitive investment grants for innovative biogas and biomethane projects.	
Final updated NECP and PNIEC	2024	Increases national targets.	20 TWh/year of biogas by 2030
Royal Decree-Law 7/2026	Mar 2026	Requires the government to establish mandatory annual biomethane penetration targets for non-transport gas uses and to define obligated parties, a calculation methodology, and compliance and control mechanisms. The draft Royal Decree on the Promotion of Biomethane is under preparation, planned to be in force in 2028.	

North America

United States

The United States has experienced remarkable exponential growth over the last decade, especially in biomethane – also called renewable natural gas (RNG) – primarily for road transport use. RNG consumption has risen 2.5-fold in the last five years, accelerating since 2022. RNG production in 2025 is estimated at around 151 PJ, making the United States the world's largest producer country and accounting for 38% of global production. Meanwhile, biogas use – mainly for on-site power and heat production – is slowly declining, partly reflecting the upgrading of some facilities to produce RNG.

Key **transport sector** regulatory frameworks, including the federal Renewable Fuel Standard (RFS) and the California Low Carbon Fuel Standard (LCFS), have been largely driving this rapid US expansion. The RFS mandates a minimum volume of biofuels, with biomethane contributing 93% of all cellulosic biofuels. Meanwhile, California's LCFS and similar, more recent policies in Washington and Oregon, set GHG emission reduction targets and established a carbon credit market in which RNG producers can generate revenues based on the carbon intensity of their gas.

State low-carbon fuel standards and the federal RFS, complemented by financial support in the form of tax credits under the 2022 Inflation Reduction Act (IRA),

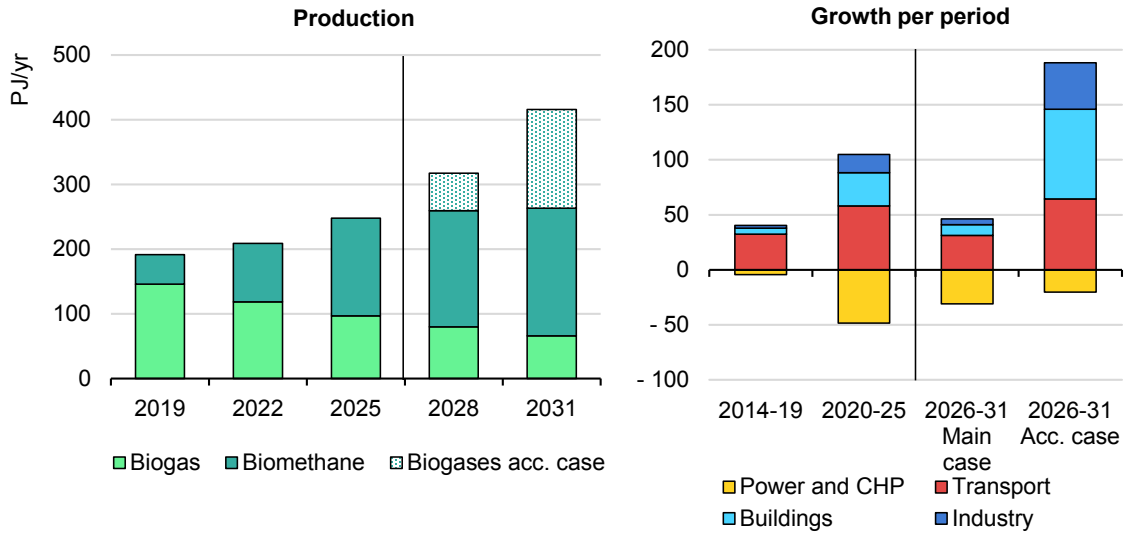
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subsequently extended under the One Big Beautiful Bill Act (OBBBA) of 2025, provide generous support and stable revenues, which have driven market expansion. As a result, RNG made up 94% of the fuel share in natural gas vehicle fleets in 2025 (up to 99% in California), indicating a high degree of technical saturation in transport sector use.

According to the Environmental Protection Agency (EPA) – which released a new Set 2 rule in 2026 establishing RFS volume obligations – following natural gas transport market saturation, RNG uptake has become demand-driven rather than supply-limited, with supply outpacing demand. Slower growth is expected compared with the rapid expansion of the past three years, although an increase in the natural gas fleet, mainly in buses and trucks, will continue to support demand. The deployment of larger engines for long-distance hauling could also open new opportunities for higher uptake in transport over the forecast period. We have incorporated this potential driver into our accelerated case.

Other recent regulatory changes that will shape the future of RNG include the revision of California's LCFS in 2025, with methane avoidance credits that generate ultra-low-emissions manure-based RNG (with carbon intensities averaging roughly -300 g CO_2/MJ) phasing out by 2040 for new projects breaking ground after 2029. As highlighted in its 2022 Scoping Plan Update, California is preparing to transition from using RNG in transport to heating and hydrogen production in the long term, as transportation electrification advances.

US biogas and biomethane historical and forecast production (left) and growth per end-use sector (right)



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Notes: Acc. case = accelerated case. CHP = combined heat and power.

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Uptake in **thermal applications** remains slower than in transport but is gaining increased attention from policymakers and gas utilities, as developers seek to diversify beyond transport into utility procurement, corporate gas supply and industrial heat. Legislative support is expanding: 37 states have enacted measures to promote RNG use in residential and commercial sectors, including mandatory or voluntary blending targets and cost-recovery mechanisms for utilities. For instance, California's Senate Bill (SB) 1440 mandates 12.2% RNG by 2030, while Oregon's SB 98 establishes voluntary targets of up to 30% by 2050 and Nevada's SB 154 sets a target of 3% by 2035. To track renewable thermal credits, CleanCounts has emerged as the market leader to monitor compliance with mandatory programmes outside of transport.

In addition, several gas utilities have adopted voluntary targets and are increasingly involved in RNG procurement, production and interconnection infrastructure development. Voluntary corporate consumers are also expected to play a role in RNG demand growth in upcoming years as they aim to comply with voluntary environmental, social and governance (ESG) goals and offer "green" products to their clients. BPAs signed with industrial consumers generally provide lower but more stable prices than transport markets, helping to de-risk investments and improve project bankability.

However, growth in the heat sector remains more uncertain than in transport. Revenues, which rely on green certificates backed by lower obligation levels, are likely to be less generous than those attainable from the combination of stackable federal and state incentives for transport.

In terms of feedstocks, sectoral reports show that in 2025, 64% of RNG and around 75% of biogas production came from landfill gas, the feedstock with the lowest production cost. Twenty five percent of RNG production comes from agricultural feedstocks, mainly animal manure from dairy farms, supported by methane avoidance credits that result in ultra-low carbon intensity scores and competitive advantages in markets such as California with its LCFS. Feedstock diversification is expected to continue. California is supporting the diversion of organic waste from landfills to produce RNG, a more environmentally friendly use of waste as it avoids fugitive methane emissions from landfills.

Overall, the United States remains one of the world's most dynamic RNG markets, but the 2025-2026 policy environment is steering the sector towards more demanding higher-quality projects with robust feedstock access, low carbon intensity and diversified offtake. Federal policy continues to favour transport RNG, particularly cellulosic RIN-generating pathways, while state clean fuel standards and gas-utility programmes are becoming the main drivers for geographic diversification and thermal demand.

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US biogas/biomethane sector main policies and regulations

Policy	Year	Key information
Federal regulations		
Renewable Fuel Standard (RFS) **programme**	2005	Creates a federal renewable transport mandate, setting a minimum volume of renewable fuels in transportation fuel sold in the United States.
Inflation Reduction Act (IRA)	2022	Establishes investment tax credits (ITCs) and production tax credits (PTCs) for renewable energy and alternative fuel projects for 10 years, for construction beginning before 2025.
Set Rule **Implementation (RFS)**	2023	Introduces renewable volume obligations for transport (RINs) for 2023, 2024 and 2025.
One Big Beautiful Bill Act (OBBBA)	2025	Modifies tax credits under IRA and extends the Clean Fuel Production Tax Credit from end-2027 to end-2029. It restricts production to the US and feedstocks to Mexico, the US and Canada. RNG from animal manure can get credits above the cap at USD 1.00/gal and is allowed to report negative carbon intensity scores.
"Set 2" Rule **on RFS biofuel volume obligations**	Mar 2026	Introduces new annual volume obligations (RINs) for transport under the RFS for 2026 and 2027, with specific volumes for RNG under cellulosic biofuels. It partially waives the 2025 cellulosic biofuel volume requirement.
State regulations		
California Low Carbon Fuel Standard (LCFS**)**	2007	Establishes annual carbon intensity (CI) standards in transport and a trading system for carbon credits. Targets 10% lower transport carbon intensity by 2020.
California Dairy Digester Research and Development Program	From 2014	Introduces Department of Food and Agriculture grants for dairy digesters, for max. 50% of total final cost, with applications accepted until October 2024 only.
California Renewable Gas Standard (RGS) procurement program D.22-02-025	2022	Implements Senate Bill (SB) 1440. It mandates procurement targets for gas utilities, for gas produced from organic waste diverted from landfills (0.5 bcm/year by 2025) and from all feedstocks (about 12.2% or 2.06 bcm by 2030).
California 2022 Scoping Plan	2022	Roadmap to carbon neutrality by 2045. It establishes more ambitious GHG reduction targets.
California LCFS amendments	2025	Increases CI reduction targets from 13.75% to 22.75% for 2025, and from 20% to 30% by 2030. It introduces a new auto-acceleration mechanism in case targets are met. Methane avoidance credits for projects starting after 2029 will phase out in 2040 if RNG is used in transport and from 2045 if it is used for hydrogen production. Additional deliverability requirements will be added from 2041 (RNG for transportation) or from 2046 (RNG for hydrogen).
Oregon Clean Fuels Program	2016	Establishes an annual CI standard target. Differences from the standard generate or require credits.
Washington Clean Fuel Standard	2023	Establishes an annual CI standard target. Differences from the standard generate or require credits.

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Policy	Year	Key information
Washington HB 1409	2025	Updates and increases Clean Fuel Standard targets to a 45% CI reduction by 2038 from the 2017 level, and new annual reduction standards in 2026 and 2027.
New Mexico Clean Transportation Fuel Program	2024	Establishes an annual CI standard target. Differences from the standard generate or require credits. The target is to reduce CI 20% by 2030 and 30% by 2040 compared with 2018. Implementation starts in 2026.
Colorado Clean Heat Plan, SB21-264	2021	Requires gas utilities to submit plans to reduce their GHG emissions. RNG is eligible.
Hawaii Clean Fuel Standard, SB 2999	Jul 2026	Aims to reduce the carbon intensity of transport fuels by 10% below the 2019 level in 2035 and by 50% in 2045. The standard will take effect in 2029.

Canada

Canada's biogas and biomethane markets are following a pathway similar to that of the United States, with a combination of federal and provincial regulations driving growth. Historically concentrated in landfill gas used for power generation, output is increasingly diversifying into biomethane (RNG), drawing on wastewater and animal manure feedstocks. However, biomethane production is still in its early stages, and Canada currently imports almost half of the RNG it consumes from the United States.

In recent years, the country has introduced both federal and provincial regulatory updates. Current regulation is focused on transport, supported by federal Clean Fuels Regulations and investment support under the Clean Fuels Fund, with specific provincial targets driving advances, especially in British Columbia and Quebec. The pipeline of announced projects indicates accelerated growth for RNG in the short term. Domestic RNG production, around 16.5 PJ in 2025, is expected to grow 75% to 2031 in our forecast.

Canada biogas/biomethane sector main policies and regulations

Policy	Year	Key information	Target
Federal regulations			
Greenhouse Gas Pollution Pricing Act (GGPPA)	2019	Establishes the federal requirement for a carbon pricing system, including a "fuel charge" or carbon tax on fuels and an Output-Based Pricing System (OBPS) for large industry emitters. Final administration and programme design rests with the provinces. The consumer fuel charge was removed in 2025.	
GHG Offset Credit System	2022	In this system, methane-emission reduction projects for landfills and liquid manure management can generate credits that can be traded to satisfy OBPS requirements.	

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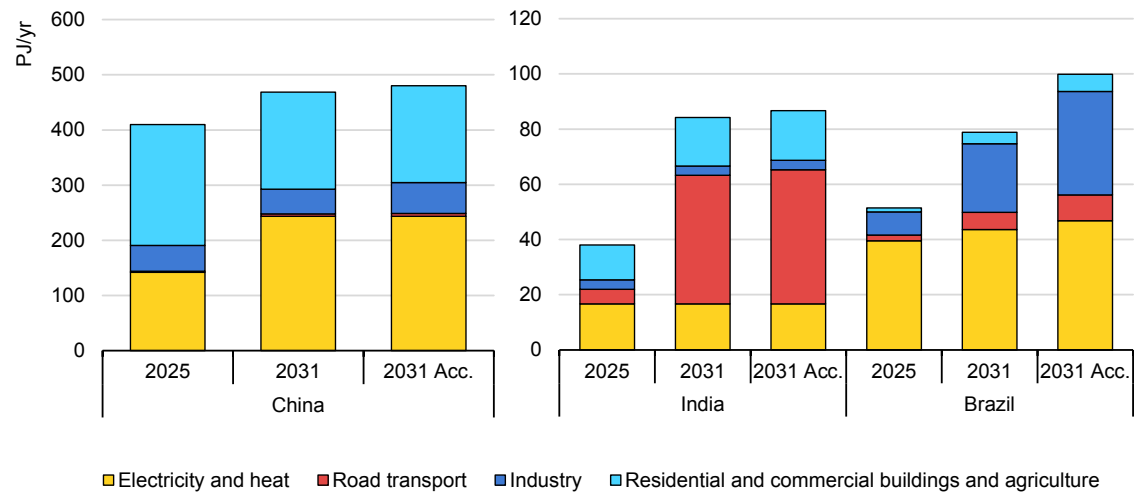
Policy	Year	Key information	Target
Federal regulations (continued)			
Clean Fuels Fund (CFF)	2022	Offers investment support for new clean fuel-producing plants and their expansion, feasibility and engineering studies and setting of biomass supply chains. The CFF was extended to 2029-2030.	
Clean Fuels Regulations (CFR)	2023	Requires transport fuel suppliers to gradually reduce the carbon intensity of their fuels. Low-carbon fuels, including biomethane, generate credits that can be sold to comply with obligations.	15% reduction in carbon intensity by 2030 relative to 2016 level
Provincial regulations			
British Columbia			
CleanBC Roadmap to 2030	2021	Requires a minimum blend of renewable and low-carbon gases in pipelines.	15% RNG by 2030
Low Carbon Fuels Act	2024	Updates the previous Low Carbon Fuel Standard from 2010. It sets progressive carbon intensity reductions in transport fuels for road, aviation and marine uses. RNG can generate credits for compliance.	30% CI reduction by 2030 from 2010 baseline
Greenhouse Gas Reduction Regulation (GGRR)	Updated 2024	Establishes how regulated utilities can pass the marginal costs of GHG emission reductions on to clients.	
Québec			
Renewable Gas Mandate	2019, amended 2022	Sets binding quotas requiring gas distributors to deliver a minimum share of renewable gases by 2025, extended to 2030 in 2022.	1% RNG by 2020, 2% by 2023, 5% by 2025, 7% by 2028 and 10% from 2030
2030 Green H_2 and Bioenergy Strategy	Amendment 2025	Sets the ambition to reduce GHG emissions through green hydrogen and bioenergy deployment.	4 Mt CO_2-eq/yr by 2030

Large emerging economies: China, India and Brazil

China, India and Brazil share several features in their biogas market development. All three are large economies with emerging green gas sectors, supported by ambitious public policies that have been strengthened over the last three years. Their policy objectives are also aligned in their aims to expand clean energy production based on domestic resources; reduce reliance on imported natural gas; and foster rural economic development. At the same time, they face similar challenges, including limited gas infrastructure and the need to establish robust feedstock supply chains. Despite these constraints, national and international investment is flowing into all three countries, supporting the development of dynamic project pipelines.

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China, India and Brazil production of biogases per end-use sector and forecast to 2031, main and accelerated cases



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Note: Acc. = accelerated case.

India

Historically, biogas in India has been used in rural areas, promoted since the 1980s for household production units to provide clean cooking fuel and for community plants to generate power. However, the Indian government has been implementing a series of policies to support the production of biomethane (also called compressed biogas [CBG] in its compressed form[16]) since 2018 and more intensively over the last three years. In 2026, the government released a Unified Scheme for Compressed Biogas that integrates different programmes across the CBG supply chain and provides robust support for the next 10 years.

The comprehensive regulatory framework includes a blending mandate for CBG use in transport and domestic consumption in city gas grids; guaranteed CBG offtake at a fixed price (through the Sustainable Alternative Towards Affordable Transportation [SATAT] programme); support for CBG distribution through the CBG-City Gas Distribution (CGD) synchronisation scheme; assistance to aggregate feedstock supplies via the Biomass Aggregation Machinery programme; and incentives to valorise digestate co-products through the Market Development Assistance for Promotion of Organic Fertilizers.

Most CBG produced in India is used in the transport sector, supported by rapid expansion of the CNG vehicle fleet, which grew more than 16% per year between 2022 and 2024 according to the Petroleum and Natural Gas Regulatory Board. CNG vehicles accounted for about 20% of passenger vehicle sales in the 2025

[16] India's Standard IS 16087:2025 regulates CBG's methane content at a minimum level of 95% mol.

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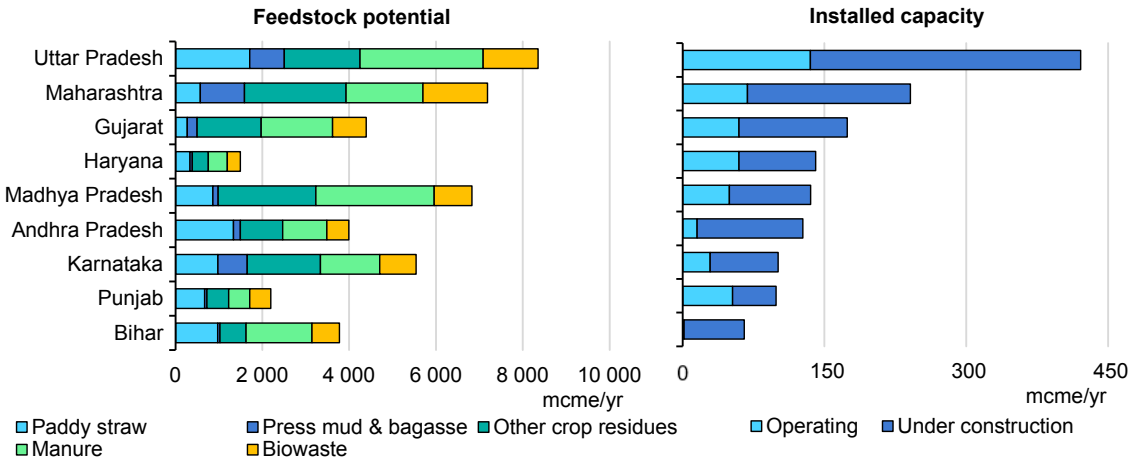
fiscal year. Domestic use of CBG, also included in the blending obligation, is expected to rise as injection into city gas grids increases as networks are extended.

The announcement of new projects, now consolidated in the central Gobardhan registry, shows promising accelerated growth in upcoming years. The main challenge that could delay expansion is the currently low utilisation rate of existing plants (around 35%) due to a number of factors, including difficulties in securing sufficient feedstock for continuous operation throughout the year, limited storage and market options for digestate, and logistics constraints to deliver CBG to end users. In 2025, 79% of CBG produced in India was delivered using pressurised cylinders transported on trucks (mobile cascades), but injection into gas grids, particularly in city gas distribution networks, is advancing alongside the broader development of gas infrastructure.

Among major economies, India has one of the highest feedstock potentials to produce biogas and biomethane (more than 75 bcme), mainly from agricultural residues and animal manure. State policies in the main agricultural states also favour development of the sector.

India is expected to achieve exponential (almost ninefold) CBG production growth by 2031. If new plants can operate at capacity factors at least comparable with existing facilities, national blending targets appear to be within reach. The accelerated case assumes that blending mandates are achieved by 2030. Biogas, which is mainly produced in smaller rural units, is expected to continue declining gradually.

India's waste and residue feedstock potential per state (left), and operating and under-construction capacity per state (right)



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Note: mcme = million cubic metres equivalent. Installed capacity is based on the Gobardhan registry as of December 2025.
Sources: IEA (2026), India Bioenergy Market Report, IEA (2026), Interactive Map of Global Biogas and Biomethane Potential, (accessed 23 September 2026).

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India biogas/biomethane sector main policies and regulations

Policy	Year	Main ministry	Key information
Galvanizing Organic Bio-Agro Resources (GOBARdhan) Initiative	2018	MoPNG (before Ministry of Jal Shakti)	Comprises several initiatives encouraging organic waste valorisation through transformation into CBG or organic manure. It launched the Unified Registration Portal for biogases in 2023.
Sustainable Alternative Towards Affordable Transportation (SATAT) initiative	2018	MoPNG	Enables purchase offtake agreements with oil and gas companies, with a minimum purchase price guaranteed until 2029; provides some tax exemptions.
Waste to Energy Programme (WtE)	2022	MNRE	Targets increased energy production from urban, industrial and agricultural wastes, providing financial assistance to produce biogas, power from biogas and bio-CNG. Bio-CNG plants can receive INR 40 million per 4.8 metric tonnes/day up to a cap of INR 100 million per plant.
National Biogas Programme (NBP)	2022	MNRE	Offers financial assistance to set up small- and medium-sized biogas plants (up to 2 500 m^3/day).
CBG Blending Obligation (CBO)	2023	MoPNG	Mandates blending of CBG into transport fuel and domestic piped gas, starting at 1% in FY 2025-26 and rising to 5% in FY 2028-29. It targets 750 established CBG projects by FY 2028-29.
CBG-CGD synchronisation scheme	2021, updated 2023	MoPNG	Operated by GAIL, sets tripartite contracts between CBG producers, CGD entities and GAIL at a set price, managing transport via mobile cascades or injection into CGD networks.
Market Development Assistance (MDA) **for Promotion of Organic Fertilizers**	2023	DoF	Available from FY 2023-24 to FY 2025-26, supports the marketing of fermented organic manure (FOM), liquid fermented organic manure (LFOM) and phosphate-rich organic manure (PROM), by-products of biogas and CBG plants, with aid of INR 1 500/Mt. Products need to comply with the Fertilizer Control Order and pass quality tests.
Biomass aggregation machinery (BAM) **scheme**	2024	MoPNG	Provides financial assistance to CBG producers to procure machinery, up to 50% of the cost or INR 9 million per set.
Fertilizer Control Order (FCO)	amended 2025	DoF	Introduces a new category for organic carbon enhancers from CBG plants.
Development of Pipeline Infrastructure (DPI) **scheme**	2025 revision	MoPNG	Provides up to 50% financial support for laying connection pipelines and CBG injection points in CGD grids.
Union Budget 2026-27 **Excise Duty Exemption**	Feb 2026	MoF	Excludes the entire portion of biogas and CBG from central excise duty when calculating the tax on CNG blended with CBG to promote clean green fuels.

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Policy	Year	Main ministry	Key information
GOBARdhan, **India's National Unified Scheme for Compressed Biogas**	Aug 2026	MoPNG	Creates an integral framework to accelerate CBG production through assured offtake, stable pricing, capital assistance, pipeline connections and access to financing, with a budget of INR 237 billion. It unifies previous support schemes across the value chain and sets long-term support to FY 2035-36, aiming to increase CBG production nearly tenfold. The CBG price is set at INR 2 110/MBtu and capital assistance at up to INR 20 million per tonne/day of installed capacity, including for feedstock aggregation, digestate processing and value addition.

Notes: MoPNG = Ministry of Petroleum and Natural Gas. MNRE = Ministry of New and Renewable Energy. DoF = Department of Fertilizers. MoF = Ministry of Finance.

China

Like India, China has a long-standing tradition of producing biogas from small-scale digesters in rural areas, supported by government subsidies. The number of these small units peaked at 42 million in 2015 before decreasing. In parallel with this decline in household-plant use, the government introduced a new strategy in 2019 aiming to develop larger-scale industrial biogas plants, including to produce biomethane (also called bio-natural gas or BNG in China).

As part of the new strategy, China introduced ambitious biomethane production targets of 10 bcm/yr by 2025 and 20 bcm/yr by 2030. Some sources interpret this target to refer to all industrial-scale production, including biogas used directly and purified streams. Progress since 2019 has been slower than anticipated, but policy updates aim to accelerate development.

The 14th Five-Year Plan for Renewable Energy Development (2021-2025) called for the construction of large demonstration plants in regions with strong agricultural and livestock resources. Several national standards for biogas plant design and biogas quality were therefore introduced, along with efforts to better integrate biogas production with other sectors such as waste collection. China's biogas strategy is also closely aligned with broader goals, including rural development (e.g. under the Rural Energy Revolution plan) and the increased use of organic fertilisers.

More recently, the new 15th Five-Year Plan (FYP) framework for 2026-2030 includes biomass as an energy source to be developed according to local conditions, explicitly pivoting from using biogas for power generation to producing gas (biomethane) and heat. The new FYP aims to further integrate biogases into renewable energy plans, fossil fuel substitution, circular economy strategies and energy security, moving away from considering it as a technology for waste management only.

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Additionally, in 2025 and 2026, China's voluntary emission reduction trading market (CCER) incorporated new methodologies allowing biogas and biomethane projects to generate credits covering biogas for power, for direct supply or for biomethane produced from pig manure and agricultural waste, either mixed or non-mixed. This allows producers the possibility to generate additional revenues from the production of biogases, complementing existing capital investment subsidies and tax exemptions.

Nevertheless, China generally lacks comprehensive support for operations that have been successful to develop the sector in other countries, and upfront investment subsidies play a main role. An exception is its operational subsidies framework, introduced recently through the National Green Development Fund, covering straw collection, storage and transport to produce biogas and BNG – especially relevant in the major agricultural provinces. In terms of feedstocks, policy support also focuses on the integration of agricultural residues, animal manure and municipal organic waste from cities. Due to gas infrastructure limitations in some areas with strong feedstock potential, new plants have sometimes been planned in hubs covering a county area, connecting biogas production with end consumers.

While biogases are still used mainly in buildings and for power generation (88% of consumption), industry sector demand for biogas and BNG is rising, for both energy and chemical applications. Export-oriented Chinese industries are increasingly demanding internationally certified biomethane as a way to shrink their carbon footprint and reduce pressure from new trading measures such as the European CBAM. In 2024, Chinese industries signed the first BPAs to secure biomethane supplies.

Additionally, the industry sector is considering using biomethane as a raw material to produce low-emissions hydrogen and methanol. In addition to low-emissions methanol, the Chinese shipping sector is looking into the alternative of using bio-LNG (liquefied biomethane) in vessels. Bio-LNG demand is also surging for long-distance trucking.

China's biogas and BNG output is expected to accelerate as newly installed capacity comes online over the forecast period. In the main-case forecast, combined biogas and biomethane production rises 14% over 2026-2031, and biomethane output alone is projected to double. Nevertheless, we have revised our forecast downwards from last year, mainly because lower-than-expected growth in 2025 is delaying acceleration in market activity.

Achieving the 2030 target of 20 bcm (around 720 PJ) would thus require faster progress and is likely to happen later than planned. The forecast estimates that biogas and biomethane production in 2030 will reach 64% of the target in the main case and 65% in the accelerated case.

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China biogas/biomethane sector main policies and regulations

Policy	Year	Key information
Chinese Rural Household Biogas State Debt Project	2003	Aims to reduce pollution from agricultural wastes and solve energy shortages in rural areas.
Working Plan of Upgrading and Transforming Rural Biogas Projects	2015	Promotes the central government's BNG pilot projects for the first time.
County Planning Outline on the Development and Utilization of BNG	2017	Released by the National Energy Administration, requests that projects be integrated into county energy planning.
Guideline Opinions for Promoting the Industrialised Development of the Biomethane Industry	2019	Targets production of 10 bcm of biomethane annually by 2025 and 20 bcm by 2030.
14th FYP **for the Development of Renewable Energy**	2021-2025	Introduces support for large-scale demo projects and diversified feedstocks, and for planning of areas.
Action Plan for Methane Emission Control	2023	Promotes the use of animal manure.
Action Plan for Pollution Prevention and Control in Agriculture and Rural Areas	2021-2025	Aims to accelerate rural domestic waste and wastewater treatment.
Rural Energy Revolution Pilot County Construction Plan	2023	Provides instructions for provincial development and national pilot counties.
Guiding Opinions on Implementing the Renewable Energy Substitution Initiative	2024	Aims to increase renewable energy consumption, explicitly placing biomethane within China's renewable energy substitution strategy and not only as a waste-management technology. Biomethane can be used in industry, transport, buildings and agriculture.
Renewable Energy Law	Revision 2025	Requires that gas networks support biomethane connections to their grids, provided the biomethane has at least 96% purity.
15th FYP framework	2026-2030	Includes biomass as a type of energy to be developed as per local conditions. It explicitly pivots from biogas use for power generation to gas/heat production, thus focusing on biomethane. It emphasises strengthening rural distributed renewables.
15th FYP for the Construction of a New Energy System	Jun 2026	Includes biomethane as part of national energy-system planning. It calls for deployment wherever it is geographically appropriate.
15th FYP for Renewable Energy **Development**	Jul 2026	Explicitly states the promotion of biomethane industrialisation, the development of non-food biofuels and the integration of these activities with agricultural and municipal organic waste utilisation. It also calls for the expanded use of biomethane in transport.

Policy	Year	Key information
National GHG voluntary emission reduction trading market (CCER): new methodologies	2025, 2026	Provides guidelines for calculating GHG emission reductions, enabling projects to generate and sell carbon credits in the voluntary market. Their implementation is expected to provide additional revenues to biomass projects. China introduced new methodologies for biogas and biomethane projects in 2025 and proposed a further one in 2026: - Large-scale pig farm manure biogas recovery and utilisation - Centralised agricultural waste treatment - Centralised anaerobic digestion and biogas engineering for kitchen waste (under consultation)
Renewable energy minimum consumption share	Aug 2026	Establishes minimum non-electric renewable energy consumption, including of renewable heat, renewable hydrogen, ammonia and methanol, and biofuels and other non-electric biomass energy sources. Although there are no specific targets for biogases, it could potentially impact biogas production by enabling a demand-side mechanism.
Incentives		
Financial support for investments		Provides CNY 1 500/m^3 of digester volume, with a limit of 35% of investment and CNY 30 million per project.
Tax credit		Exempts companies from all corporate income tax for the first three years, and half for the following three.

Brazil

Building on its extensive experience in biofuel development, Brazil has included biomethane in its national Fuel of the Future strategy, creating one of the most advanced policy frameworks outside of Europe.

The country's main policy instrument is a decarbonisation obligation based on biomethane use starting in 2026, requiring natural gas producers and importers to reduce the emissions of their gas by including a share of biomethane in their supply or by purchasing biomethane guarantee-of-origin certificates (CGOBs) in a tradeable certificate system. Targets are set at 0.5% for 2026 (revised down from an initial 1%) with a maximum emissions reduction of 10% for upcoming years.

Recent regulatory developments support the legal basis of the Fuel of the Future Law of 2024. In 2025 and 2026, policy work focused on developing the necessary secondary regulation: Decree No. 12,614/2025 formally regulates biomethane under the law and, additionally, two National Petroleum Agency (ANP) resolutions released in 2026 determine how to calculate each agent's obligations and compliance mechanisms (No. 995/2026) and establish certification and

registration procedures for CGOBs (No. 996/2026). While the main regulatory architecture is in place, some technical rules and market-monitoring arrangements are still under development.

Currently, biogases produced in Brazil are derived 64% from municipal solid waste (mostly from landfills) and the treatment of wastewater sludge, 18% from industrial organic waste, and a growing share (19%) from agricultural residues and animal manure. A specific feature of Brazil's biomethane market is that additional feedstock potential (from sugarcane residues, vinasse, livestock manure and agro-industrial residues), estimated at around 67 bcme, is located mainly inland, whereas natural gas grids and large consumption centres are concentrated along the coast and in some industrial corridors. Biomethane-production projects are emerging as distributed energy in areas where feedstocks and energy consumers are located close to each other. For example, biomethane can be used in transport in heavy-duty fleets that operate near production sites (for example, trucks and agricultural machinery at sugar mills). Industry is also a main demand sector.

The book-and-claim system allows obligated agents (natural gas producers and importers) to acquire CGOBs, while the gas is physically used locally in transport, the agro-industry or isolated local markets. This reduces the need for extensive gas grids. Aligned with this, some developers are adopting the hub model wherein small producers aggregate their output, transporting it by truck to a central hub where it is injected into pipelines.

In the main-case forecast, combined production of biogas and biomethane is expected to grow 53% by 2031. Biomethane alone could rise from below 14 PJ in 2025 to over 41 PJ in 2031 in our main case, and to over 62 PJ in the accelerated case with faster market response.

Brazil biogas/biomethane sector policies and regulations

Policy	Year	Key information
Special Incentive Regime for Infrastructure Development (REIDI)	2022	Normative Ordinance 37, which includes biomethane in project types eligible for tax exemption for materials and equipment under the REIDI scheme.
National Methane Emission Reduction Programme	2022	Promotes biogas and biomethane growth; encourages methane credits in the carbon market.
Fuel of the Future Law and National Programme	2024	Creates the National Programme for Decarbonisation of Natural Gas Producers and Importers and Incentives for Biomethane. Natural gas producers must reduce their GHG emissions by transitioning to biomethane (through self-production or purchase of certificates). The GHG emissions reduction target is to be set annually.

Policy	Year	Key information
Decree No. 12,614/2025	Sep 2025	Regulates the national decarbonisation programme for natural gas producers and importers and the incentive for biomethanation, including the issuance of CGOBs.
ANP Resolution No. 995/2026	Mar 2026	Establishes how to calculate each agent's annual obligations and sets compliance mechanisms through CGOB cancellation or retirement.
ANP Resolution No. 996/2026	Mar 2026	Regulates the certification of biomethane, including certification and registration procedures.
CNPE Resolution No. 686/2026	Apr 2026	Revises the GHG emissions reduction target to 0.5% from initial 1% relative to the past 10-year average.
ANP Resolution No. 1006/2026	Aug 2026	Sets biomethane quality rules.

Emerging markets: Southeast Asia

Overall, Southeast Asian countries showed combined production of over 80 PJ of biogas and biomethane in 2025, concentrated mainly in Thailand, Indonesia and Malaysia. Southeast Asia remains one of the world's most promising biogas regions owing to its large agricultural base, extensive livestock production, food processing industries and, importantly, its large palm oil sector. Feedstock potential for producing biogases is estimated at almost 65 bcme (around 2 300 PJ).

The biogas market is still dominated by wastewater-treatment biogas for power generation, heat and captive industrial use, while biomethane production (upgraded biogas for grid injection or transport) is emerging. However, the model is transitioning from traditional biogas towards biomethane-led decarbonisation, with Thailand, Indonesia and Malaysia emerging as the most relevant markets. Key policy drivers include increased domestic renewable energy production, industry decarbonisation – particularly to help manufacturers meet international requirements such as the EU Carbon Border Adjustment Mechanism (CBAM) – and methane emission reductions in the palm oil sector through the treatment of palm oil mill effluent (POME).

Thailand currently has the region's largest biogas market, thanks to long-standing feed-in tariffs to support power generation and broader decarbonisation plans. Feedstock availability is diverse and includes livestock waste (especially pig manure), cassava, food-processing waste and wastewater. Compared with neighbouring countries, Thailand benefits from more mature gas infrastructure and a stronger project-development ecosystem.

Meanwhile, **Indonesia** has the most abundant feedstock resources in the region because of its extensive palm oil industry. POME as well as empty fruit bunches and other residues are plentiful. POME treatment also helps reduce methane

emissions from the palm oil sector. Indonesia has a clear national strategy and bioenergy targets that include biomethane, and it is developing specific regulations. While POME was initially used mainly to supply electricity on-site, policy focus is shifting towards producing biomethane to replace imported LPG, diesel and natural gas.

Malaysia is also shifting from traditional biogas towards commercial biomethane supply. The country introduced a National Energy Transition Roadmap in 2023 and a National Biomass Action Plan 2023-2030 and is developing certified biomethane supply chains for industrial customers.

Development in the region could be further accelerated by growing demand for clean fuels in Singapore and Japan, underpinned by recent policy developments. In September 2025, **Singapore** launched its Biomethane Sandbox, a market demonstration and regulatory pilot to assess imported biomethane use in the gas-fired power sector and industry, targeting 300 MW of capacity. The sandbox is a novel policy approach to biomethane deployment, relying on imports rather than domestic production, reflecting Singapore's limited organic resource base and aiming to facilitate supply-demand matching ahead of wider market deployment.

Japan is emerging as a potential biomethane market, with efforts focused on both supporting domestic production and exploring imports, given the limited availability of organic resources in the country. Japanese companies have already begun securing supplies, signing their first deals with US producers. In 2025, low-carbon gases were included in Japan's decarbonisation policy framework through the 7th Strategic Energy Plan, while in 2026 the Green Transitions emissions trading system (GX-ETS) was launched. However, Japan is still working on developing the regulatory framework to support large-scale biomethane deployment.

At the same time, a new wave of liquefied biomethane or bio-LNG projects is emerging in Southeast Asia. The largest announced bio-LNG project in the world, the Straits Bio-LNG plant in Muar, Malaysia (along the Strait of Malacca), is expected to produce around 0.36 bcme per year, while dozens of other bio-LNG projects have been announced across Indonesia, Malaysia and Thailand. These investments are being spurred by growing demand for low-emissions fuels in maritime shipping; opportunities to export biomethane to Singapore to help decarbonise its gas-dependent power sector; and the potential to displace natural gas imports in domestic markets, particularly during periods of high LNG prices such as those experienced during the Middle East crisis in 2026.

While the outlook is promising, these markets remain at an early stage of development, and the pace of growth will depend on, among other factors, the implementation of supportive policies across the region.

Maritime shipping emerging demand

Recent regulatory frameworks aiming to decarbonise the maritime sector are creating new opportunities for biomethane use, in the form of bio-LNG.

Under the European Union's **FuelEU Maritime** regulation, applicable from 2025, ships above 5 000 GT calling at EU ports must reduce their well-to-wake GHG intensity, starting with a 2% reduction from the 2020 value in 2025, rising to 6% in 2030 and ultimately 80% by 2050. The regulation covers both well-to-tank fuel emissions (from their production and supply pathway) and tank-to-wake (from their use onboard, including for the energy conversion technology, e.g. engine, fuel cell, as well as engine-dependent emissions, such as methane slip).

The resulting GHG intensity is expressed in g CO_2-e/MJ of energy used onboard. This is particularly relevant for methane-based fuels (LNG, liquefied biomethane and e-methane), as methane slip from engines can significantly affect their overall GHG intensity due to methane's higher global-warming potential (GWP) compared with CO_2 (25 over a 100-year period on the GWP scale).

Additionally, the **EU ETS** covers maritime transport emissions from 2024. Certified bio-LNG can lower a ship's exposure to EU ETS costs where biogenic CO_2 is treated favourably under the relevant accounting rules.

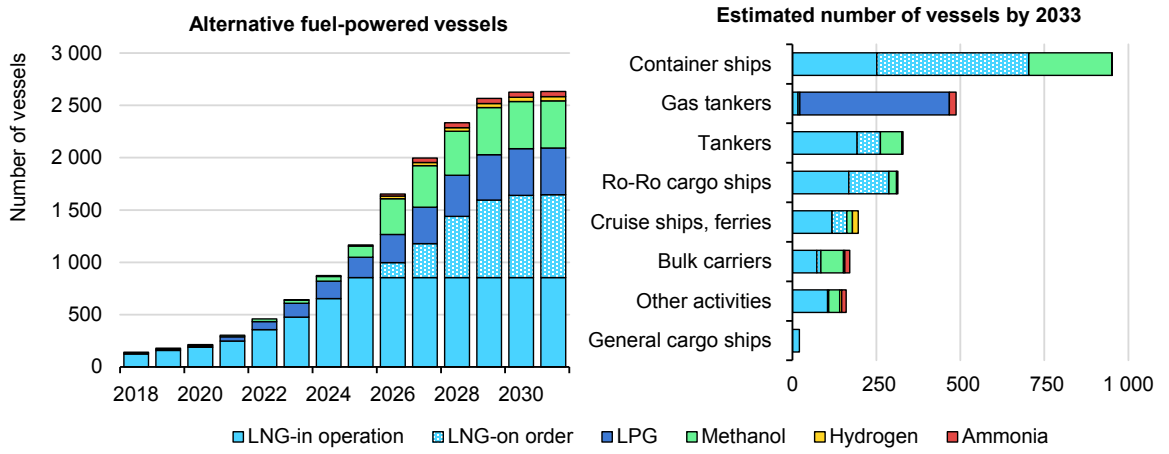
At the global level, the **IMO Net-Zero Framework** would have a substantial impact because it proposes a worldwide fuel-intensity standard and GHG pricing mechanism on a well-to-wake basis for ships above 5 000 GT, but its adoption has been delayed, meaning entry into force is now uncertain and could be postponed until 2028 the earliest.

Liquefied biomethane can be used as a drop-in fuel in LNG-fuelled and dual-fuel vessels that can switch between LNG and conventional fuel oils, and shipping companies can take advantage of existing LNG tanks and bunkering infrastructure, avoiding major changes, and benefit from the operational expertise already established for methane as a maritime fuel. The opportunity is particularly relevant for the growing LNG-capable fleet and bunkering network: in 2025, LNG bunkering was available at 222 ports globally, with 62 additional ones having facilities under construction.

LNG and dual-fuel vessel fleets are expanding rapidly: the number of LNG-fuelled ships more than doubled between 2022 and 2025 (853 vessels) and, based on the current orderbook, is expected to double again by 2030. LNG as a marine fuel was initially adopted in LNG carriers using boil-off gas from their cargo, before expanding into ferries, offshore supply vessels and subsequently large commercial vessels.

A range of vessel types currently use LNG as a fuel. LNG carriers, using boil-off gas from their LNG cargo, accounted for over 12 million tonnes of fuel use in 2024, while the use of LNG as a dedicated marine fuel is much lower, around 2.9 million tonnes in 2024. It has been adopted particularly rapidly by container ships (1.3 million tonnes used in 2024), for which the number of LNG-fuelled vessels and new orders grows 2.8-fold to 2033. Although LNG represented only 6.7% of total reported fuel oil use in ships in 2024, its consumption is growing faster than for other fuels, representing 8% of ships on order, compared with 0.84% of ships in operation.

Historical and ordered alternative fuel-powered vessels (left) and distribution per type of ship by 2032



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Notes: LNG = liquefied natural gas. LPG = liquefied petroleum gas. The two LNG categories do not include LNG carriers, powered by their cargo's boil-off LNG. "Gas tankers" does not include LNG carriers. "Ro-Ro cargo ships" refers to specialised roll-on/roll-off vessels designed to transport wheeled cargo that is rolled directly on and off the ship via ramps.
Source: Adapted from the IMO Future Fuels project, with data from DNV (2026), Alternative Fuels Insight platform, (accessed 31 August 2026).

Bio-LNG uptake can benefit from this rapid expansion. Some shipping companies are securing long-term bio-LNG supply and bunkering, not only in Europe but also in China, Singapore and the United States. On the supply side, several bio-LNG projects have been announced, well positioned to serve the maritime sector. Among the largest is the liquefaction and export terminal being developed by Straits Bio-LNG in Muar, Malaysia, on the Strait of Malacca.

For biomethane producers, the new regulations could make shipping a premium offtake market, particularly where low-carbon feedstocks such as manure generate very low or even negative well-to-tank emissions. FuelEU Maritime rewards low lifecycle carbon intensity rather than mandating a specific fuel, allowing bio-LNG to compete with other low-emissions fuels. Eligible fuels include biodiesel and HVO, for vessels using fuel oil or diesel engines, bio-LNG and liquefied e-methane for LNG-powered vessels, and low-emissions methanol,

ammonia and hydrogen, which generally require dedicated engines or fuel-cell systems. Among vessels using alternative fuels, LNG-fuelled ships currently account for the largest share of new orders, excluding conventional fuel-oil and diesel-powered vessels.

However, some regulatory questions remain around certificate trading, mass balancing, treatment of subsidised biomethane volumes and cross-border recognition. A final challenge is methane slip: even renewable methane must demonstrate robust lifecycle benefits, since upstream leakage, liquefaction emissions and onboard methane slip can erode climate gains.

Overall, these regulatory frameworks can create an opportunity for biomethane markets to diversify beyond road transport and gas-grid injection, with some analysts suggesting that FuelEU Maritime alone could become a significant demand pull for European bio-LNG, although dedicated European bio-LNG capacity remains limited at present. Considering current LNG fuel consumption and excluding LNG carriers, a 20% bio-LNG mix would result in bio-LNG consumption of just over 28 PJ/yr (around 0.8 bcme). Taking fleet expansion to 2031 into account, a conservative estimate of the potential market for bio-LNG would be around 2 bcme/yr by 2031[17]. Other analysts report higher estimates of around 6 bcme by 2035, expecting stronger growth in LNG use. Bio-LNG shares could be larger depending on market conditions, and whether sufficient sustainable biomethane supplies become available at the required scale.

[17] These growth estimates were not included in this year's forecast.

Chapter 5. Energy security and renewables

Summary

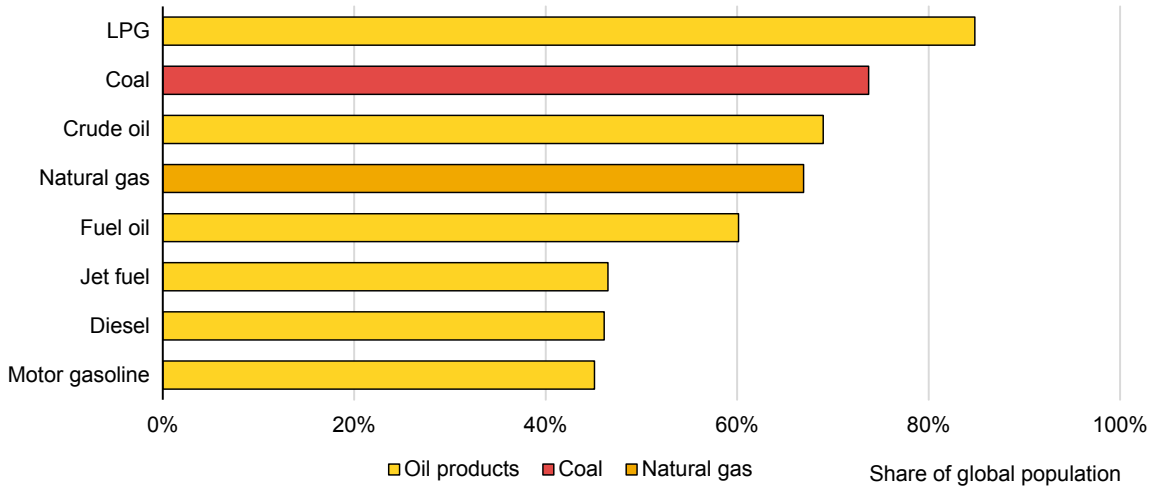
- Renewables can strengthen energy security by reducing dependence on imported fossil fuels and limiting exposure to fossil fuel price volatility.
- Without growth in renewable energy uptake since 2010, global fossil fuel demand would have been around 8% higher in 2025. The increase of renewable energy supply reduced fossil fuel demand by 41 EJ in 2025, avoiding 615 Mtce of coal, 515 bcm of natural gas and 2.4 mb/d of oil consumption.
- Most renewables-related fossil fuel savings during 2010-2025 came from the power sector (nearly 70%) followed by renewable heat (24%). Coal and natural gas replacement provided the most savings, while biofuel use in transport reduced oil product consumption by 4%.
- China achieved the largest absolute fossil fuel savings. In 2025, fossil fuel demand would have been 14% higher in India, 13% higher in Latin America, and 12% higher in the European Union, without renewables growth since 2010.
- Renewable heat production is strengthening energy security: without expansion since 2010, fossil fuel use for heating would have been around 15 EJ (8.5%) higher in 2025, including 150 bcm more natural gas demand.
- Buildings accounted for over 40% of avoided fossil fuel use for heating in 2025 and industry for more than half, thanks to heat pump, renewable electricity and modern bioenergy uptake.
- Biofuels are reducing oil import dependence in transport. Growth since 2010 avoided almost 20 EJ of oil product demand and lowered fuel import reliance by 24 percentage points in Brazil and 19 percentage points in Indonesia.
- Biogases provide a domestic alternative to imported natural gas. While reducing global gas imports by around 3%, they meet 36% of gas demand in Denmark and cut imports by 8-10 percentage points in several European markets.
- Renewable ammonia could become a strategic energy security option, reducing dependence on imported fossil fuels and fertilisers as renewable electricity, electrolyser and financing costs decline.

Introduction

Today, around 60% of the world's population lives in countries that import natural gas, oil and coal. Exposure ranges from around half for refined oil products to 85% for liquefied petroleum gas (LPG), while roughly two-thirds depend on imported natural gas and three-quarters on imported coal. Russia's invasion of Ukraine in 2022 and the current conflict in the Middle East have reignited concerns about energy security, particularly in countries dependent on imported fuels.

High fossil fuel prices, supply disruptions and greater market volatility highlight the macroeconomic and strategic risks associated with import dependence. As a result, governments are increasingly pursuing energy security alongside affordability and emissions-reduction objectives.

Share of global population living in net-fossil-fuel-importer countries, by fuel, latest available year



IEA. CC BY 4.0.

Note: LPG = liquefied petroleum gas.
Source: IEA (2026), World Energy Balances, (accessed July 2026).

Energy security depends on an energy system's reliability and affordability, and whether it can withstand supply, infrastructure and market disruptions. Expanding renewable energy use can reduce imported fossil fuel dependence and limit exposure to fossil fuel price volatility. However, integrating variable renewable energy sources such as wind and solar PV requires additional investment in power system flexibility, grids and storage.

Furthermore, renewable energy deployment can also create new dependencies on international supply chains for equipment and critical minerals. The overall impact of renewables on energy security therefore depends on the structure of each energy system and the policy priorities shaping deployment.

This chapter focuses on the contribution of renewables in reducing fossil fuel imports in the electricity, heat and transport sectors. Chapter 1 covers other emerging energy security dimensions, including supply chains and system integration.

Global overview

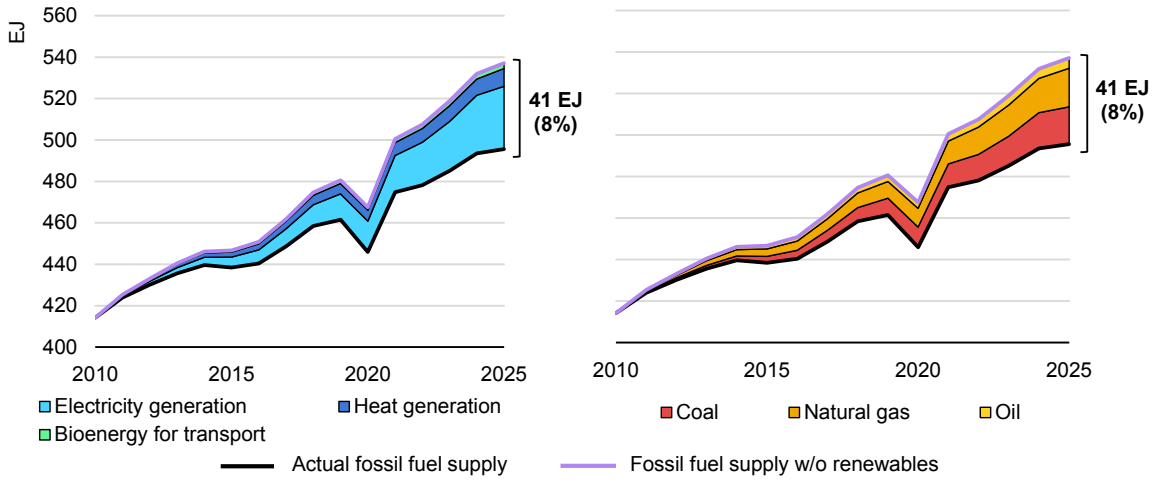
Between 2010 and 2025, the global renewable energy supply nearly doubled owing to rapid growth in the electricity, heat and transport sectors. Over the same period, however, the fossil fuel supply increased a further 18%, as renewable expansion was not sufficient to fully meet rising global energy demand. Fossil fuels therefore continue to make up most of the global energy supply.

Our analysis uses 2010 as the baseline, reflecting the start of large-scale deployment of modern renewable technologies, particularly solar PV and wind, while also capturing the continued expansion of renewable heat and biofuels.

Global fossil fuel demand would be 8% higher without renewable energy growth since 2010

Renewables have substantially reduced the amount of fossil fuels needed to meet growing energy demand. In 2025, their use avoided 41 EJ of fossil fuel consumption, broadly equivalent to India's total energy supply.

Fossil fuel demand avoided by use of renewables by sector and fuel, 2010-2025



IEA. CC BY 4.0.

Notes: "Heat generation" excludes electricity used for heat, which is covered under "electricity generation". The baseline is 2010 because it marks the start of a decade of accelerated growth in renewables across electricity, heat and transport, particularly with the large-scale expansion of solar PV and wind power.

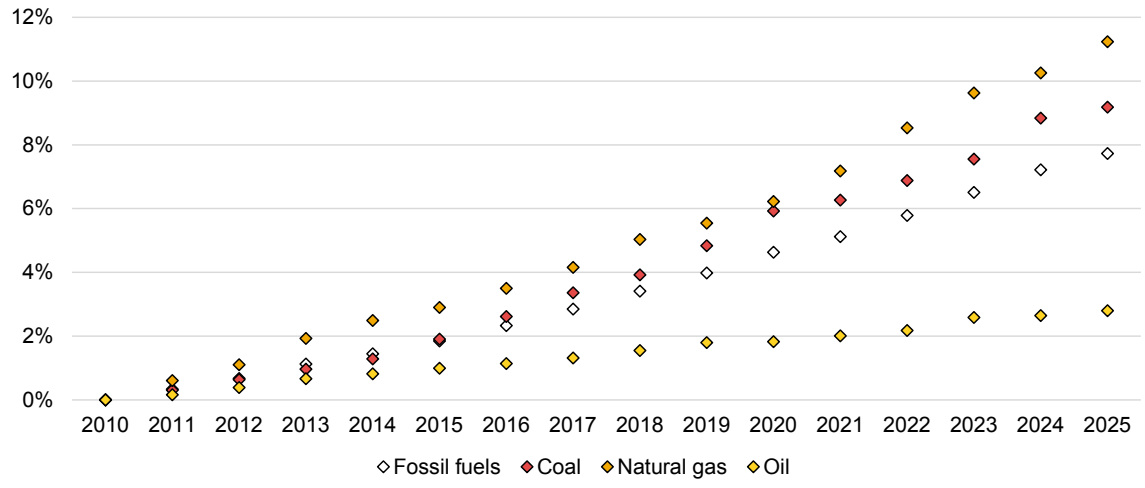
Without the expansion of renewables since 2010, global fossil fuel demand in 2025 would have been around 8% higher, requiring an additional:

- 615 Mt of coal equivalent, accounting for 43% of avoided fossil fuel demand.
- 515 bcm of natural gas, broadly equivalent to Europe's annual gas consumption and representing 45% of the total.
- 2.4 mb/d of oil, equivalent to nearly 3% of global oil demand and accounting for the remaining 12%.

Between 2010 and 2025, cumulative fossil fuel savings reached 275 EJ. Renewables avoided 116 EJ of coal and 120 EJ of natural gas demand between 2010 and 2025**.** These savings stemmed primarily from rapid expansion of renewable electricity, which increasingly displaced coal- and gas-fired generation. **Oil savings were considerably lower at 39 EJ**, reflecting the slower uptake of renewable alternatives for transport and other oil-dependent end uses.

As renewable energy deployment has expanded, avoided fossil fuel consumption has increased steadily. **Absent the growing use of renewables since 2010, global natural gas demand would have been 11% higher in 2025 and coal demand 9% higher**. The impact on oil demand was smaller, at around 3%. Renewables have therefore made their largest contribution to energy supply security in the power sector, where they directly reduce reliance on fossil fuel-based generation.

Additional fossil fuel supply (% over total) without renewable energy growth since 2010



IEA. CC BY 4.0.

Note: "Oil" includes primary and secondary oil.

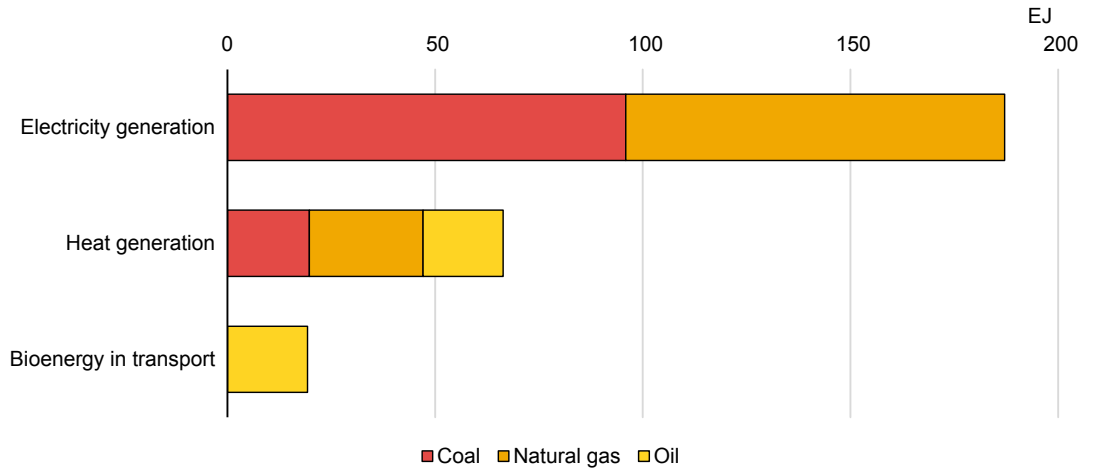
Renewables delivered most fossil fuel savings through power generation

Almost 70% of the fossil fuel reduction resulting from the use of renewables between 2010 and 2025 occurred in the power sector, reflecting the rapid expansion of renewable electricity technologies. Renewable energy use in heat accounted for a further 24% of total savings.

In the power sector, renewables have reduced coal and natural gas demand by broadly similar volumes globally, although their relative contribution varies by region depending on the composition of the electricity mix. Fossil fuel savings in heat are more diversified, reflecting the wider range of fuels used in the sector: renewables have displaced comparable volumes of coal and oil, while natural gas savings have been larger. In transport, biofuels have primarily reduced demand for oil-based fuels.

Avoided fossil fuel demand has grown most quickly in the power sector, thanks to solar PV, wind and hydropower expansion. As a result, electricity generation accounts for an increasing share of the total fossil fuel savings delivered by renewables. Progress has been slower in heat and transport, as renewable energy uptake depends more heavily on the deployment of end-use technologies, supporting infrastructure and targeted policies.

Fossil fuel energy consumption avoided by use of renewables by sector, 2010-2025



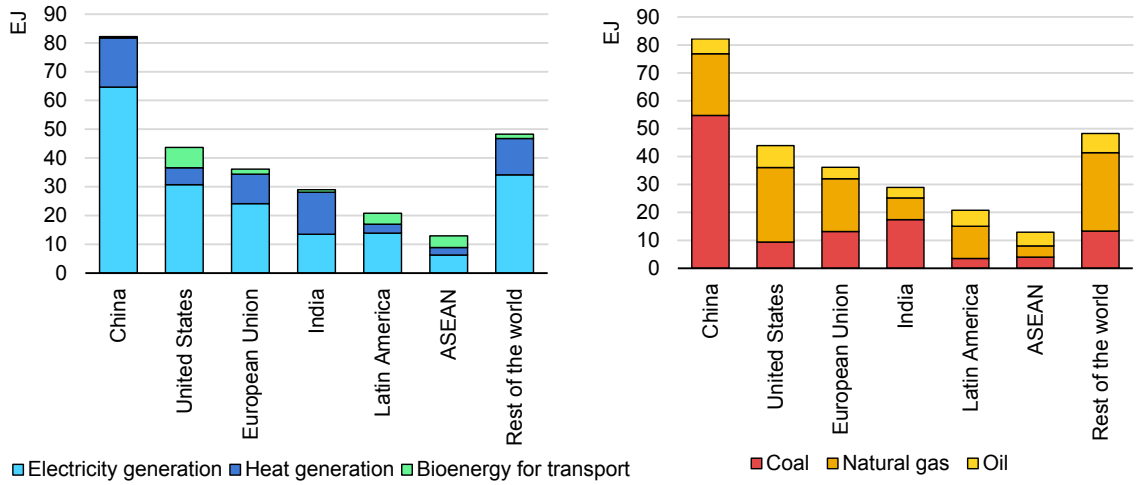
IEA. CC BY 4.0.

Notes: “Oil” includes primary and secondary oil. “Heat generation” excludes electricity used for heat, which is covered under “electricity generation”.

China had the largest fossil fuel savings from renewable energy use

Over 2010-2025, China registered the largest fossil fuel savings with increased renewable energy uptake, reflecting the scale of its energy demand and the rapidity of its renewable energy expansion. The United States, the European Union and India also achieved significant savings, as higher renewable energy use reduced the need for additional fossil fuel supplies.

Fossil fuel use avoided by renewables by region and sector (left) and by region and product (right), 2010-2025



IEA. CC BY 4.0.

Notes: ASEAN = Association of Southeast Asian Nations. Bioenergy used to generate electricity and heat is included under "electricity generation" and "heat generation". "Oil" includes primary and secondary oil.

In most regions, the power sector accounted for the majority of fossil fuel savings, reflecting rapid renewable electricity expansion. A notable exception was India, where renewable heat produced a larger share of savings owing to the importance of industrial heat demand. Biofuels made a smaller contribution globally but accounted for a greater share of fossil fuel savings in the United States, Brazil and Indonesia.

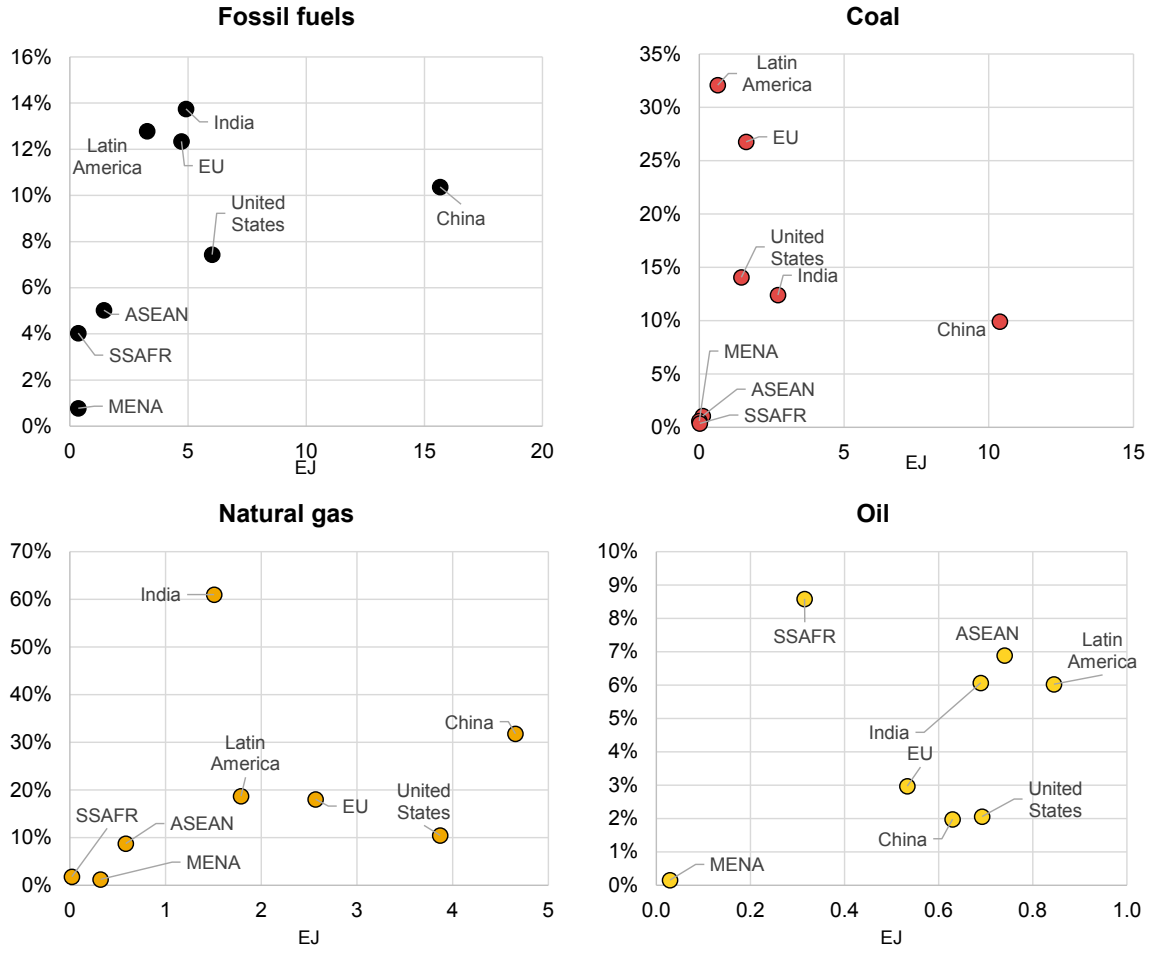
As most fossil fuel savings are delivered in the power sector, the fuels displaced reflect the composition of regional electricity systems. In China, where coal dominates power generation, renewables have primarily reduced coal demand. In the United States and the European Union, where natural gas plays a larger role in the electricity mix, renewables have delivered greater natural gas savings.

India recorded the largest relative reductions in fossil fuel demand from renewable energy deployment. Without the expansion of renewables since 2010, fossil fuel

demand would have been almost 14% higher in 2025. Meanwhile, it would have been roughly 13% greater in Latin America and 12% stronger in the European Union.

At the global level, renewables have reduced coal and natural gas demand by similar proportions. If the use of renewables had not risen considerably since 2010, coal demand would have been around 9% higher in 2025 and natural gas demand 11% stronger. However, relative impacts vary across regions according to energy system composition.

Absolute and relative fossil fuel supply reductions linked to renewables by region and product, 2025



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Notes: SSAFR = sub-Saharan Africa. ASEAN = Association of Southeast Asian Nations. MENA = Middle East and North Africa. "Oil" includes primary and secondary oil.

In China and India, renewables have had the largest relative impact on natural gas demand, reflecting the comparatively small role of gas in their energy mixes. In China, natural gas demand would have been around 32% higher without

renewables, compared with 10% for coal. Nevertheless, coal accounted for the largest volume of avoided fossil fuel demand because of its dominant role in China's energy supply.

In the European Union, renewables have had the greatest relative impact on coal demand, which would have been almost 27% higher in 2025. This reflects both the displacement of coal by renewables and the broader decline in coal consumption, which increases the relative contribution of avoided demand.

Electricity supply

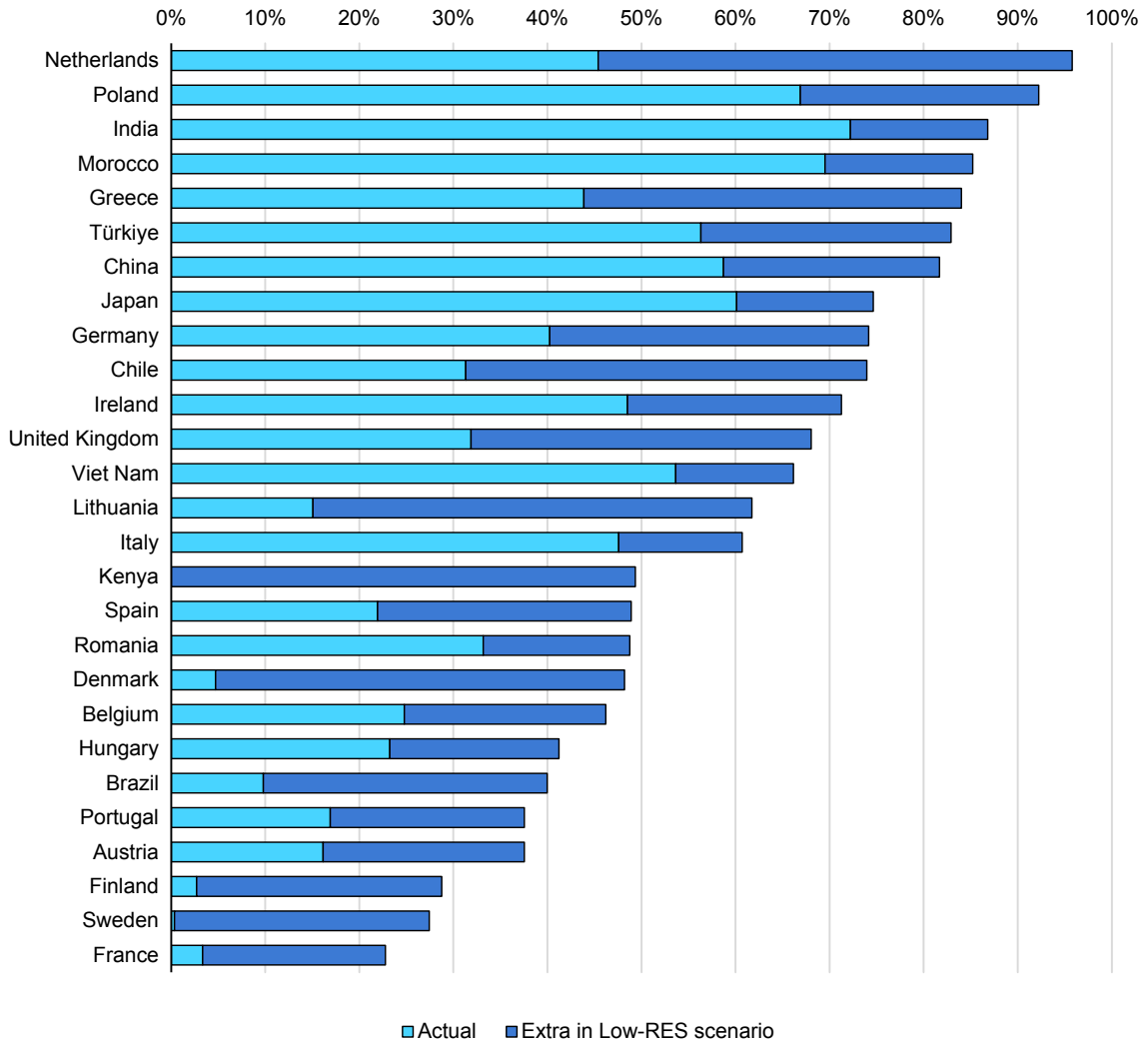
Renewable energy technologies strengthen energy security by generating electricity without continuous fuel inputs[18] and – when they displace imported fuels – reducing dependence on external energy supplies. Although renewable energy equipment may be imported, most assets require relatively limited external inputs once installed and can operate for decades. Their deployment therefore reduces exposure to fuel supply disruptions and fossil fuel price volatility, strengthening both energy security and economic resilience in fuel-importing countries.

More than 4 500 GW of renewable capacity was added globally between 2010 and 2025, led by solar PV, which accounted for more than 60% of additions, followed by onshore wind (25%) and hydropower (10%). By 2025, renewables were supplying one-third of global electricity generation. Without this expansion, countries would have had to rely more heavily on fossil fuels to meet their electricity demand, increasing the fossil fuel share of the power mix by more than 20 percentage points in several markets. In countries with rapidly rising electricity demand, including China and India, renewables met a significant share of demand growth. In markets with stable or declining demand, such as Germany and the United Kingdom, they largely displaced fossil fuel generation.

Around 80% of global renewable capacity additions since 2010 have taken place in countries that rely on imported coal or natural gas for electricity generation. By reducing dependence on imported fuels, renewable energy strengthens energy security while improving economic resilience. Unlike for fossil fuel imports, which direct much of a country's energy-related expenditures abroad, renewable energy investments are largely infrastructure-based and can generate domestic economic value by creating local jobs in installation, generation, maintenance and supply chains.

[18] Unlike wind, solar, hydropower and geothermal, bioenergy-based electricity generation requires continuous fuel inputs. Nevertheless, domestically produced bioenergy can enhance energy security when it replaces imported fossil fuels, reducing exposure to external supply risks and price volatility.

Actual fossil fuel shares in power generation in 2025, and additions without new renewable capacity growth since 2010

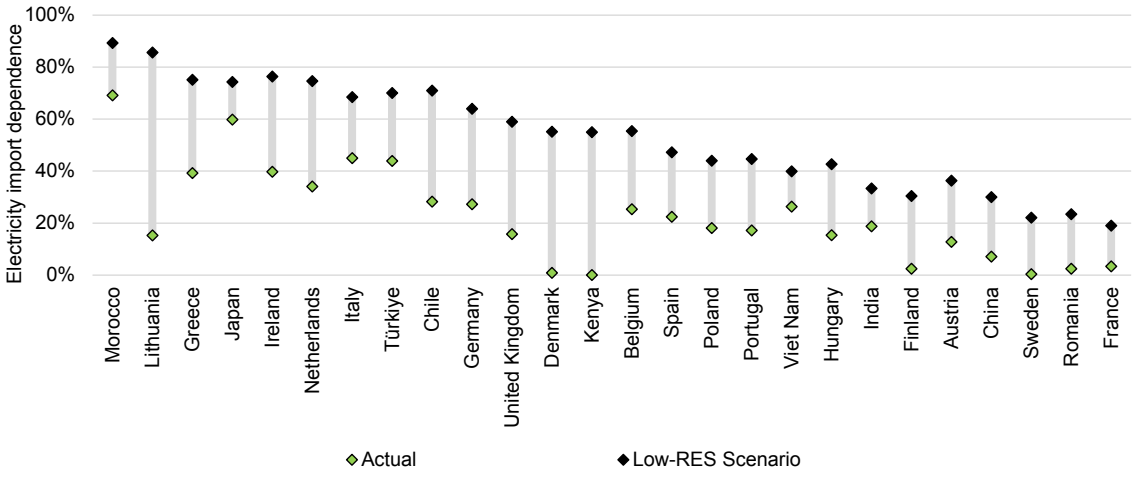


IEA. CC BY 4.0.

Note: RES = renewable energy source.

To assess energy security benefits, actual renewable energy deployment was compared with a low-renewable-energy-source (Low-RES) scenario in which no new renewable capacity was added after 2010. In this scenario, electricity generated by renewables is instead supplied by coal- and natural gas-fired plants, while other sources such as nuclear remain unchanged. The additional fossil fuel demand is assumed to be met through an increase in imports in countries already relying on them.

Actual and Low-RES fossil fuel import dependence of electricity supply, 2025



IEA. CC BY 4.0.

Note: RES = renewable energy source.

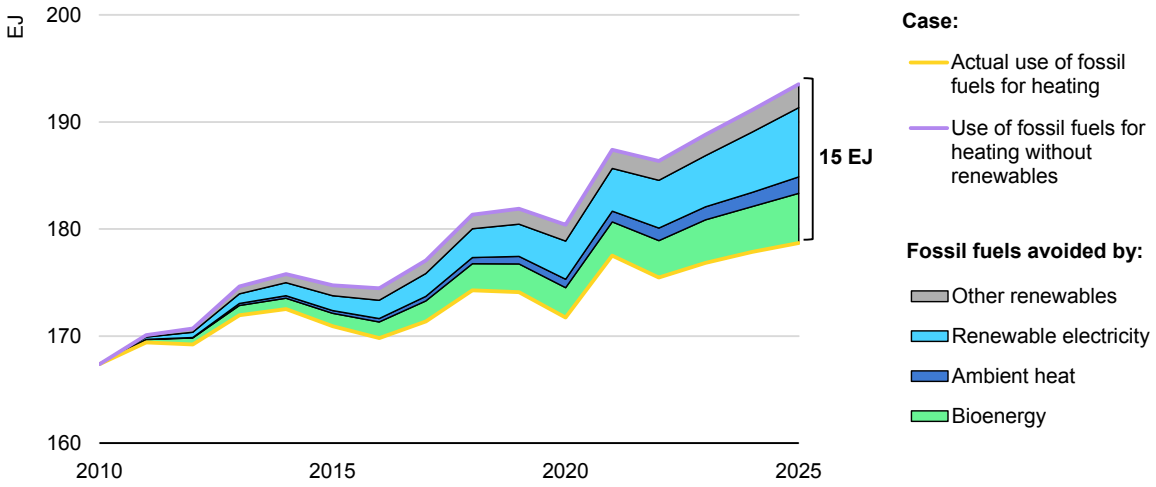
Without the expansion of renewables since 2010, many countries would be more reliant on fossil fuel-fired generation and, consequently, more exposed to fuel import risks and supply disruptions. Renewable energy deployment has reduced this exposure, particularly in fuel-importing countries such as the United Kingdom, the Netherlands, Greece, Chile, Germany, Morocco and Japan. The impact has been greatest in Lithuania and Denmark, reflecting strong wind power growth, and in Kenya, where renewables met all additional electricity demand.

Heat

The production of heat for industrial processes, for space and water heating in buildings and for agricultural applications is the largest energy end use, accounting for around half of global final energy consumption. It also remains highly fossil-fuel-intensive: modern renewables met just 15% of global heat demand in 2025, while the remaining 85% was supplied predominantly by coal, natural gas and oil, used directly or through electricity and district heat generation, leaving households and industry exposed to fossil fuel price volatility and, in many markets, to import dependence.

Renewable heat production has nevertheless made a measurable contribution to energy security since 2010. Ambient heat harnessed by heat pumps in buildings has more than doubled, solar thermal use has almost tripled, renewable electricity used for heat has grown more than 2.5-fold and modern bioenergy use in industry has expanded almost 50%. Had renewable heat consumption remained at the 2010 level, fossil fuel use for heating would have been some 15 EJ (8.5%) higher in 2025, equivalent to around 3% of total global fossil fuel supply. Avoided volumes in 2025 amount to over 150 bcm of natural gas – more than Russia's total gas deliveries to the European Union in 2021 – together with roughly 180 Mtce of coal and the equivalent of 1.8 mb/d of oil products.

Avoided use of fossil fuels for heating by renewable energy source, 2010-2025

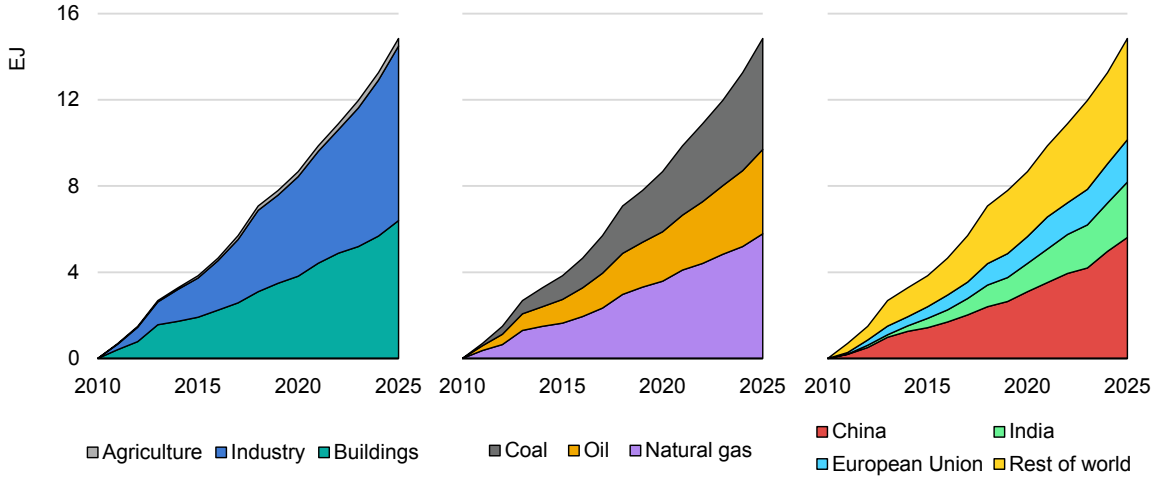


IEA. CC BY 4.0.

Notes: Avoided fossil fuel use is estimated relative to a counterfactual scenario in which renewable heat consumption stays at the 2010 level for each region and sector, with the shortfall met by coal, oil and natural gas in proportion to the fossil fuel heat mix for each region and sector. Renewable heat covers modern bioenergy (including biogas), solar thermal and geothermal energy, ambient heat captured by heat pumps, renewable district heat and the renewable share of electricity used for heat. Industrial bioenergy is counted as displacing fossil fuels.

Of total avoided fossil fuel use in 2025, two-thirds is covered by China (38%), India (17%) and the European Union (13%). Without any renewable heat growth since 2010, the renewable share of heat supply would have fallen to 9% by 2025 as demand expanded, rather than rising to 15%. Cumulatively, renewable heat expansion reduced fossil fuel demand by around 110 EJ during 2010-2025.

Avoided use of fossil fuels for heating per year by sector, avoided fuel and region, 2010-2025

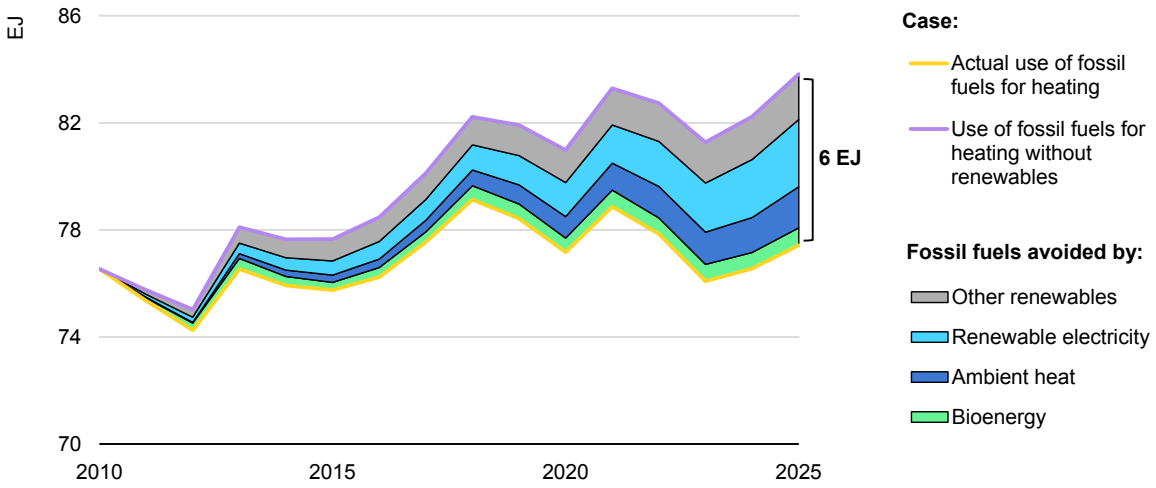


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Buildings

Buildings accounted for 6.4 EJ of avoided fossil fuel use in 2025, over 40% of the global total. More than half of the reduction was in natural gas (around 90 bcm in 2025) and a further one-third was heating oil, reducing household exposure to the fuels at the centre of the 2021-2023 energy price crisis.

Avoided use of fossil fuels for heating in buildings by renewable energy source, 2010-2025



IEA. CC BY 4.0.

Notes: Avoided fossil fuel use is estimated relative to a counterfactual scenario in which renewable heat consumption stays at the 2010 level for each region and sector, with the shortfall met by coal, oil and natural gas in proportion to the fossil fuel heat mix for each region and sector. Renewable heat covers modern bioenergy (including biogas), solar thermal and geothermal energy, ambient heat captured by heat pumps, renewable district heat and the renewable share of electricity used for heat. Industrial bioenergy is counted as displacing fossil fuels.

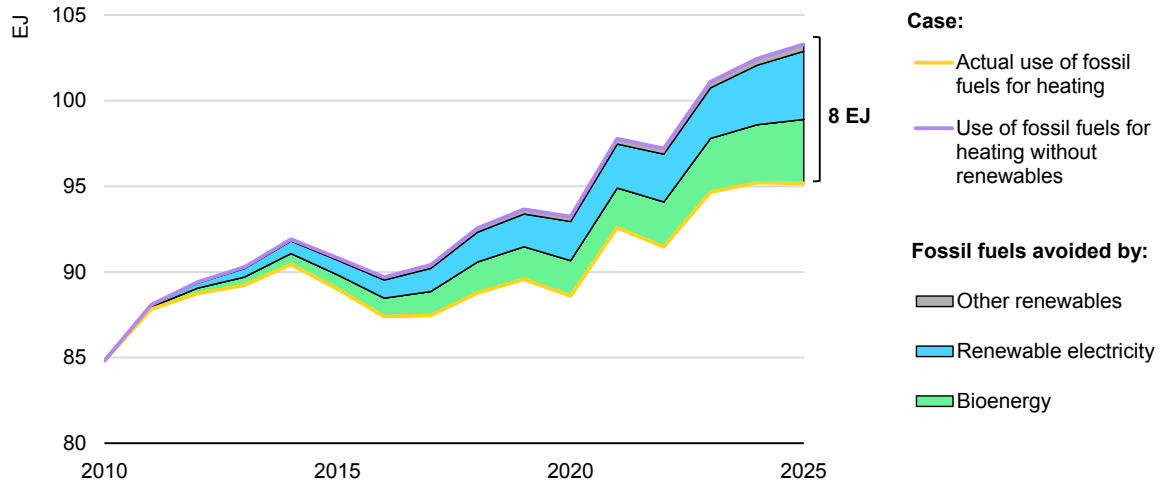
Electrification is the basis for most of the avoided fossil fuel use in buildings. Renewable electricity used for heating covered almost 40% of the buildings sector total, while ambient heat captured by heat pumps contributed a further 25%. Heat pump deployment has grown the most quickly where energy security concerns have been strongest: ambient heat use has increased almost eightfold in the European Union since 2010 and sixfold in China. The United States remains the largest user, at almost 40% of the global total. Solar thermal provided a further one-fifth of reductions in fossil fuel use in buildings, with China accounting for close to 70% of global solar thermal heat consumption. Renewable district heat, concentrated in the European Union and China, has also helped diversify urban heat supplies away from imported gas and coal.

Industry

Industry is the largest sectoral contributor to avoided fossil fuel use at 8.1 EJ in 2025 (55% of the total), and coal makes up more than half (approximately 152 Mtce). Two technologies dominate. Modern bioenergy made up for almost

half of the industry sector's avoided fossil fuel use, concentrated in emerging economies where biomass arises as a by-product of industrial processes: India accounts for 32% thanks to a 150% expansion since 2010, followed by Brazil (14%), where bagasse and black liquor provide process heat in the sugar, ethanol and pulp industries.

Avoided use of fossil fuels for heating in industry by renewable energy source, 2010-2025



IEA. CC BY 4.0.

Notes: Avoided fossil fuel use is estimated relative to a counterfactual scenario in which renewable heat consumption stays at the 2010 level for each region and sector, with the shortfall met by coal, oil and natural gas in proportion to the fossil fuel heat mix for each region and sector. Renewable heat covers modern bioenergy (including biogas), solar thermal and geothermal energy, ambient heat captured by heat pumps, renewable district heat and the renewable share of electricity used for heat. Industrial bioenergy is counted as displacing fossil fuels.

Renewable electricity contributed a similar share, led strongly by China, which represents over half of global renewable electricity used for industrial heat. For coal- and gas-importing economies these trends reduce exposure to volatile international coal, coke and gas prices, and where bioenergy is a domestic process by-product it constitutes an indigenous resource largely insulated from international fuel markets.

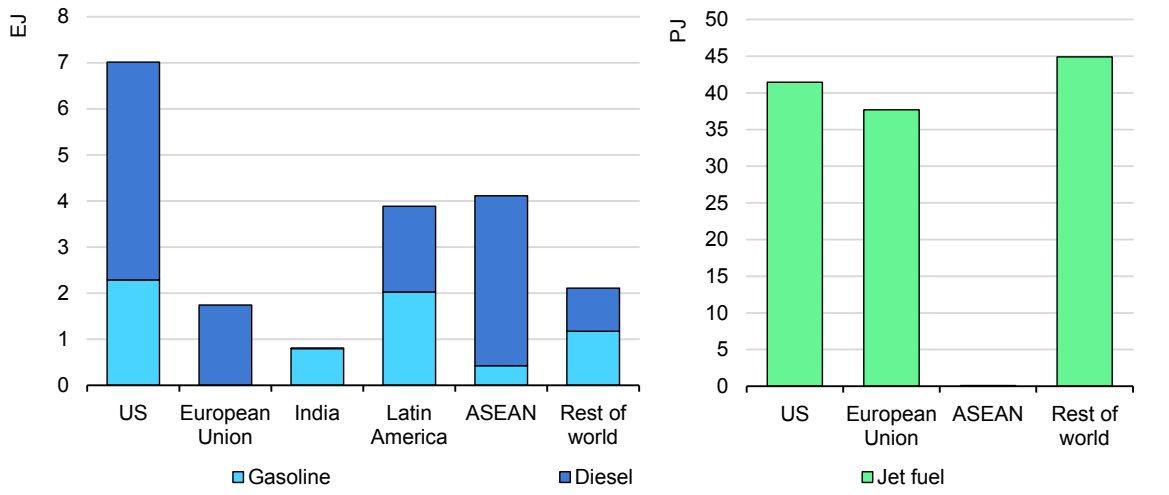
Transport

Biofuels

Biofuels strengthen energy security by reducing reliance on imported oil products, particularly in transport. Energy security has long underpinned policy support for biofuels, beginning after the 1973 oil embargo. More recently, renewed concerns over oil supply security have contributed to higher blending mandates in Indonesia, Brazil, Malaysia and Viet Nam.

Domestic biofuel industries can also generate additional revenue for the agricultural sector and, when production is sustainable, deliver significant lifecycle emissions reductions compared with fossil fuels. These benefits are encouraging some exporters of crude oil and refined products to invest in domestic biofuel production. Moreover, biofuels can be produced from a wide range of renewable feedstocks that are more geographically distributed than fossil resources, allowing countries to combine locally available resources with a diversified network of suppliers. Together with strong domestic industrial capabilities, this could support greater energy system resilience.

Fossil fuel consumption avoided through biofuel use, by region and product, 2010-2025



IEA. CC BY 4.0.

Notes: ASEAN = Association of Southeast Asian Nations. Avoided fossil fuel use is estimated relative to a counterfactual scenario in which biofuel consumption stays at the 2010 level for each region, with the shortfall met by oil products.

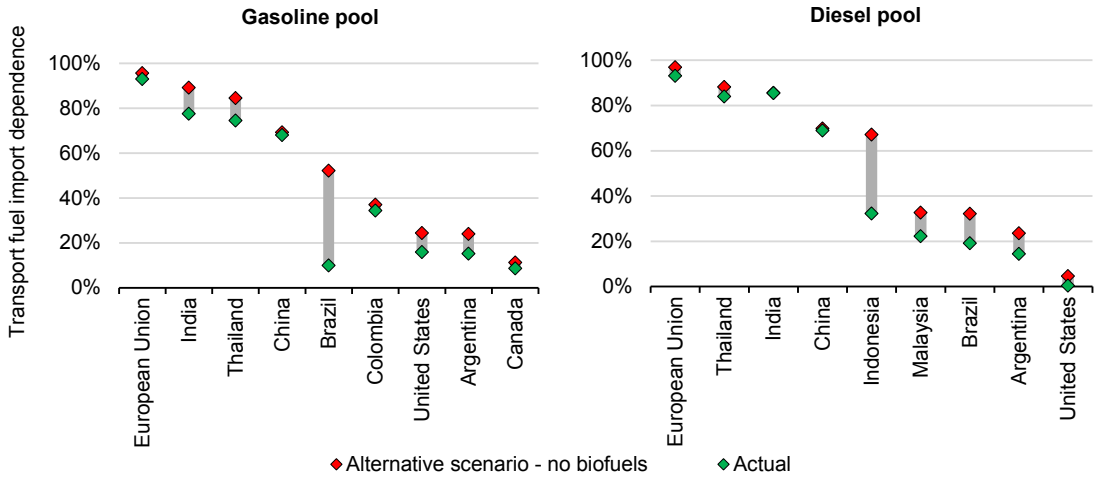
Global biofuel consumption reached 5 EJ in 2025, equivalent to around 4% of liquid transport fuel use. Growth since 2010 has avoided almost 20 EJ of oil product demand, with transport accounting for 93% (nearly 19 EJ) of the total. Biodiesel use in industry and agriculture displaced the remaining 1 EJ. Biodiesel and renewable diesel made up for 65% of avoided oil product demand by displacing fossil diesel, and ethanol for 34% in exchange for gasoline. Sustainable aviation fuels currently make a limited contribution, but mandates and incentives are expanding in the European Union, the United Kingdom, India and the United States.

To meet demand for oil products, most countries rely on either direct imports of refined fuels or of crude oil to be refined domestically. Even many crude oil exporters remain dependent on imported refined products due to insufficient refining capacity. On average, net oil-importing countries meet 55% of

their oil demand through imports. Without growth in biofuel consumption since 2010, this dependence would have risen to 57% and reached as high as 60% in the complete absence of biofuels.

The impact is substantially greater in several markets. In 2025, biofuel consumption reduced transport fuel import dependence by 24 percentage points in Brazil, and by 19 percentage points in Indonesia. In the European Union collectively, biofuels reduced import dependence by 3 percentage points. However, for individual member states the impact is as high as 14 percentage points for Finland and 10 percentage points for the Netherlands. Long-standing policy support and sustained investment in domestic production – and domestic feedstock availability – underpin the reductions in Brazil and Indonesia. By contrast, policy-driven demand encourages high levels of biofuel consumption across the European Union, which relies more heavily on imported feedstocks.

Transport fuel import dependence with and without biofuels for selected regions by fuel type, main case, 2025



IEA. CC BY 4.0.

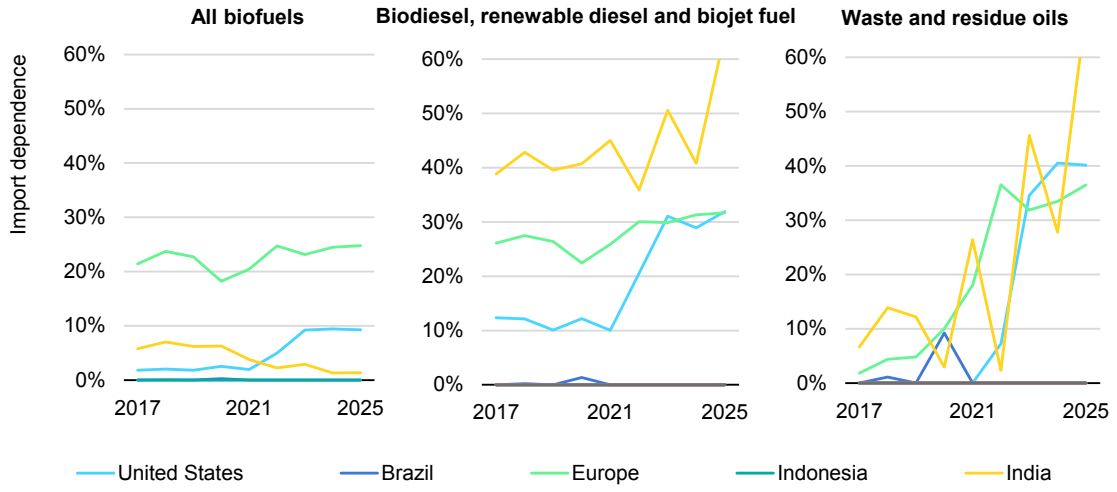
Notes: Import dependence is calculated as total net imports of oil products (gasoline and diesel), net imports of crude for domestically refined oil products, net imports of biofuels (ethanol, biodiesel and renewable diesel) and net imports of biofuel feedstocks for domestically produced biofuels, divided by total consumption of oil products and biofuels. The counterfactual scenario assumes that all biofuel consumption in the given year is directly replaced with imported oil products.
Source: IEA (2025), Oil 2025.

Impacts also vary by fuel. In Brazil, ethanol use reduces gasoline import dependence by 42 percentage points, supported by blending mandates, fiscal incentives, GHG intensity targets and widespread use of flex-fuel vehicles. In Indonesia, biodiesel lowers diesel import dependence by 35 percentage points, reflecting progressively higher blending mandates (announced target of 50% in 2026) and financial support that keeps it competitive with conventional diesel.

In most countries, however, biofuels reduce oil import dependence by less than 10 percentage points, as feedstock availability, production costs, infrastructure constraints and technical fuel standards prohibit higher blending levels. Sustained policy support addressing these conditions has been key for markets achieving the greatest energy security benefits to date.

Meanwhile, growing imports of feedstocks for biodiesel, renewable diesel and sustainable aviation fuels in Europe and the United States are drawing increasing attention to domestic supply chains. Delivering greater energy security benefits will require long-term strategies that align feedstock availability, production capacity and infrastructure development with affordability objectives. Standardised regional feedstock assessments are a practical tool to provide the data required by governments, project developers and lenders to align these objectives.

Biofuel feedstock import dependence, main case, 2017-2025



IEA. CC BY 4.0.

Notes: Feedstock import dependence is calculated as net imports divided by total domestic feedstock use for biofuel production based on the energy value of the fuels produced. Vegetable oil figures reflect trade in oils (e.g. soybean oil), not raw crops. Values for net imports of agricultural products are from the OECD, values for net imports of waste and residue oils are from Kpler and values for domestic demand are from the IEA.

Sources: OECD/FAO (2026), OECD-FAO Agricultural Outlook 2026-2035; Kpler (2026), World Annual Net Exports, Biofuels.

The use of biofuels continues to lower oil import dependence, but growing reliance on a narrow set of waste and residue oils is concentrating supply risks. Feedstock import dependence remains low in most major biofuel markets, averaging less than 10% in 2025. The three largest ethanol markets globally, the United States, Brazil and India (accounting for nearly 90% of global ethanol demand), were net exporters of ethanol feedstocks in 2025. This stems from a history of biofuel policies rooted in agricultural development and energy security, coupled with continued protection of domestic agricultural production. However,

demand for biodiesel, renewable diesel and biojet fuel is exceeding domestic feedstock supplies in several key regions, prompting a rise in imports, particularly of waste and residue oils, with 65% of imports originating in China, Malaysia and Indonesia.

Feedstock import dependence remains low for biodiesel in Indonesia and Brazil, where production is closely linked to domestic feedstock availability, and blending rates are adjusted to local supplies and cost. In India, domestic biodiesel production remains relatively small, at less than 1% of the global biodiesel market, with feedstock availability being the binding constraint on achieving the 5% blending target for 2030.

In the European Union and the United States, however, imports have increased rapidly, particularly for waste and residue oils, with combined imports more than doubling since 2022. Although annual US imports have fallen 12% from a 2024 peak of over 3 Mt, the United States and the European Union together accounted for nearly 70% of global waste and residue oil imports in 2025. In both regions, increasingly stringent sustainability criteria, production incentives and concerns over increased indirect land-use change (ILUC) risk from crop-based feedstocks have led governments to design policies favouring waste and residue oils in the production of bio-based diesels.

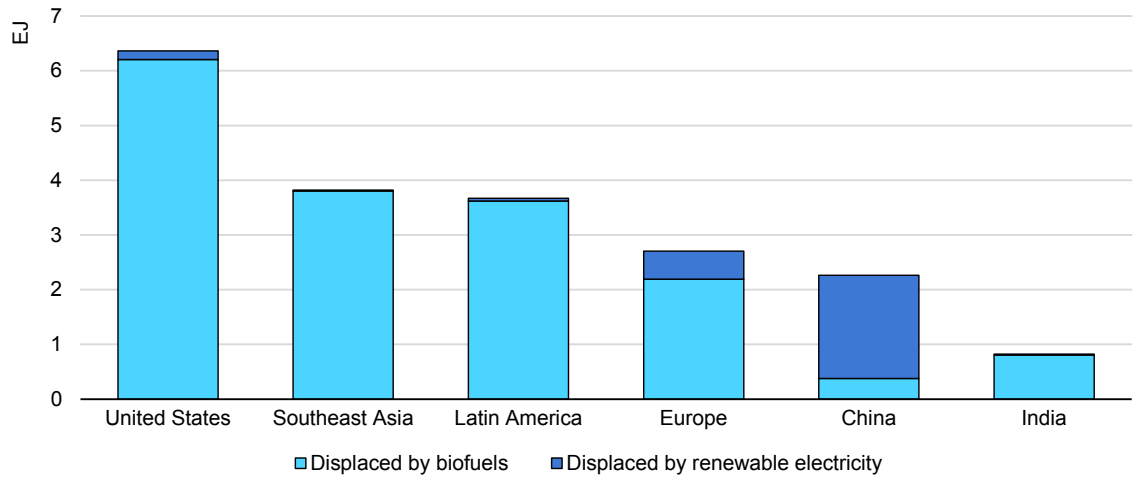
Following the rapid increase in imports – and subsequent concerns about supply fraud – both the European Union and the United States put oversight measures in place. The EU Union Database for Biofuels (UDB) is a global traceability tool used for tracking feedstocks from point-of-origin to EU market placement, to prevent double counting and fraud. In the United States, the California Low Carbon Fuel Standard (LCFS) now requires attestations and traceability obligations, the first phase of broader third-party sustainability certification to be fully implemented by 2031. Additionally, the Section 45Z Clean Fuel Production Credit (as amended by the One Big Beautiful Bill Act [OBBBA]) restricts credit eligibility to feedstocks grown/produced in the United States, Canada or Mexico only, effective 1 January 2026.

Overall, biofuels remain predominantly domestically sourced and continue to reduce import dependence in most markets. However, an additional 35% growth from 2025-2031 between the main and accelerated case would require greater trade in fuels, feedstocks and sustainability claims. Backed by robust certification and a diverse set of trading partners, such trade could support energy security, affordability and decarbonisation while limiting supply risks – but it will also be necessary to diversify beyond the currently narrow set of feedstocks, particularly waste and residue oils, as their concentration is already raising import levels and concerns over supply chain fraud.

Electric vehicles

Renewable electricity use is beginning to reduce transport sector fossil fuel dependence, though its contribution remains small relative to biofuels. Electricity demand in road transport reached nearly 850 PJ globally in 2025, almost 40% above the 2024 level, of which an estimated 280 PJ (33%) was supplied by renewable energy sources. As the shares of both renewable power generation and electrified transport demand rise, renewable electricity will further reduce reliance on imported fossil fuels in oil-importing countries.

Avoided fossil fuel demand in transport, by region and product, 2010-2025



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Notes: Avoided fossil fuel use in transport is estimated relative to a counterfactual scenario in which renewable energy consumption in transport (biofuels and renewable electricity) stays at the 2010 level in each region, with the shortfall in biofuels met by oil products, and the shortfall in renewable electricity met by natural gas- and coal-fired electricity. The counterfactual scenario assumes that growth in total electricity use in transport remains at the historical level.
Source: Based on IEA (2026), Global EV Outlook 2026.

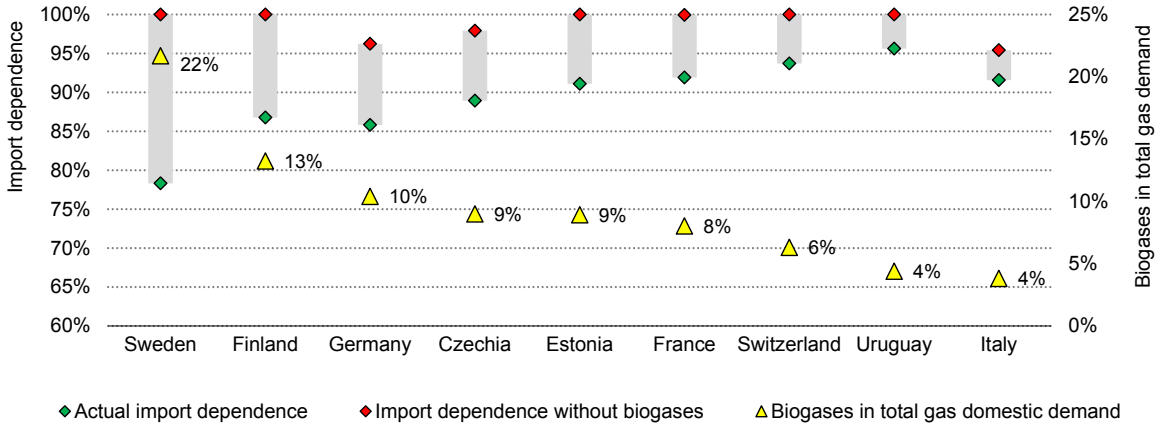
Over 2010-2025, transport consumed 3.3 EJ of electricity, with the renewable share replacing roughly 1 EJ of demand that would have been met with coal- and gas-fired generation. Accounting for average generation efficiencies, this avoided roughly 1.9 EJ of coal and 0.8 EJ of natural gas demand. At the same time, biofuels displaced nearly 19 EJ of oil products. The impact of renewable electricity is considerably greater in China and Europe, which together account for around 90% of coal and natural gas displaced by renewable electricity in transport globally.

In China, renewables growth in transport over 2010-2025 avoided nearly 2.3 EJ of fossil fuel demand, over 80% of which is coal and natural gas displaced by renewable electricity and the remainder oil products displaced by biofuels. In Europe, renewables avoided 2.7 EJ, but only 20% came from renewable electricity, with biofuels accounting for 80%.

Biogases

Biogas and biomethane uptake can strengthen energy security by diversifying gas supplies and reducing dependence on imported natural gas. As production relies mainly on locally available feedstocks, including organic waste and residues, biogases can be a domestic alternative to fossil gas. Their contribution remains modest globally, reducing natural gas imports in importing countries by around 3.3%, but is more significant in well-developed markets.

Natural gas import dependence with and without domestic production of biogases for selected countries in 2025



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Notes: NG = natural gas. Import dependence is calculated as natural gas imports divided by the sum of natural gas demand and demand for biogases. Total gas demand includes natural gas demand and demand for biogases. As a simplification, in a scenario without biogases, all biogas and biomethane production is assumed to be replaced by natural gas imports.

Despite the widespread availability of potential feedstocks, production remains geographically concentrated. In 2025, ten countries – China, Germany, the United States, the United Kingdom, France, Italy, Brazil, Thailand, Türkiye and Canada – accounted for 80% of global biogas and biomethane production.

The energy security benefits are greatest in countries without or with little domestic natural gas production. In Sweden and Finland biogases reduced natural gas import dependence by 13-22 percentage points in 2025, while in the larger markets of Germany and France they lowered the ratio by around 8-10 percentage points. Denmark recorded the highest penetration, with biogases meeting almost 36% of total gas demand. Although this does not directly reduce import dependence because Denmark is a net natural gas exporter, it demonstrates the contribution that biogases can make to domestic gas supply when supportive policies and production capacity are in place.

As production expands across regions, biogases are expected to account for a growing share of gas consumption and make a greater contribution to energy security.

Renewable ammonia

Energy security concerns are raising the strategic value of renewable ammonia, even though today it remains more expensive than fossil-based production. Ammonia is a key input for fertilisers, making its availability and price important for food security as well as industrial competitiveness. Recent disruptions around the Strait of Hormuz have reinforced the vulnerability of import-dependent economies relying on concentrated supply routes for natural gas, ammonia and urea, increasing concerns over fertiliser availability and price volatility.

Domestic renewable ammonia production, together with policies addressing fertiliser overuse, could provide an energy-security benefit by reducing exposure to volatile imported fossil fuel prices and externally priced fertiliser inputs. Renewable ammonia remains expensive today, but declining costs could strengthen its role as an energy-security option.

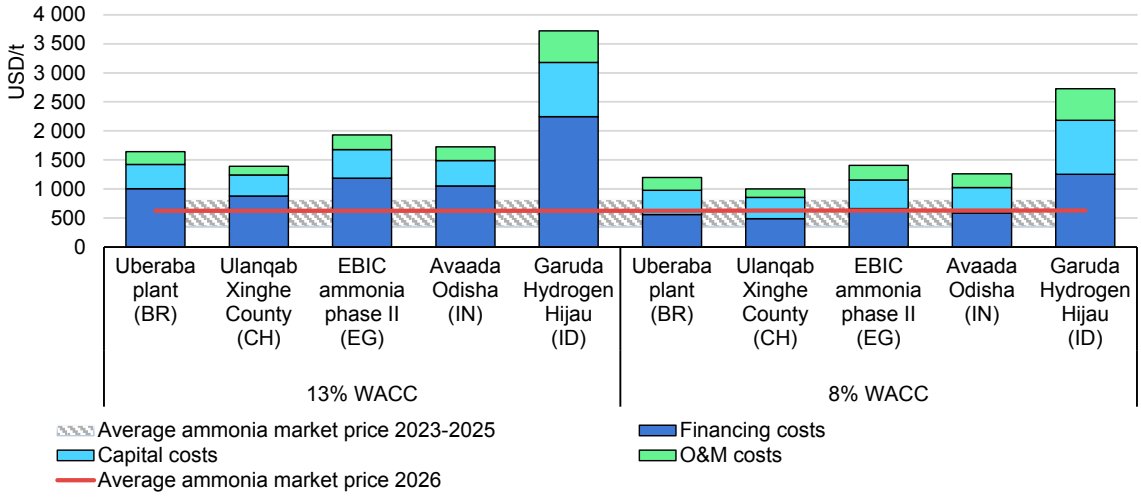
Renewable ammonia is not yet a low-cost alternative, as high upfront capital requirements, financing costs and technology costs continue to keep production costs above the fossil-based benchmarks. However, producing ammonia from domestic renewable resources would improve resilience by diversifying supply sources and limiting exposure to geopolitical shocks, even if this comes at a higher cost in the near term.

Whether renewable ammonia becomes a realistic energy-security option will depend on how quickly costs decline. Today, renewable ammonia production remains very costly for all major planned projects in Brazil, China, Egypt, India and Indonesia,[19] assuming a 13% weighted average cost of capital (WACC) and an optimal mix of wind and solar PV. Even in China (the lowest-cost case), production costs are close to USD 1 400/tonne, almost double current ammonia prices. High capital requirements for electrolysers, renewable electricity supply and ammonia synthesis make project economics particularly sensitive to financing costs, resulting in large cost differences across countries depending on renewable resource quality and capital costs.

[19] These countries were selected because they represent a broad spectrum of ammonia market profiles, including current major importers of ammonia and fertilisers and established producers of fossil-based ammonia, but all with strong renewable resource potential that could support future renewable ammonia production.

Lower financing costs can substantially improve project economics. Reducing the WACC from 13% to 8% lowers production costs for all assessed projects, highlighting the importance of access to affordable capital in determining competitiveness.

Levelised cost of ammonia for selected projects with 13% and 8% WACC in 2025



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Notes: WACC = weighted average cost of capital. BR = Brazil. CH = China. EG = Egypt. IN = India. ID = Indonesia. O&M = operations and maintenance. System lifetime: 25 years.

Projects: Brazil: Uberaba nitrogen fertiliser plant; China: Ulanqab Xinghe County Wind-Solar Power Generation Hydrogen Production Ammonia Integration; Egypt: EBIC ammonia plant phase II; India: Avaada Odisha; Indonesia: Garuda Hydrogen Hijau (GH_2).

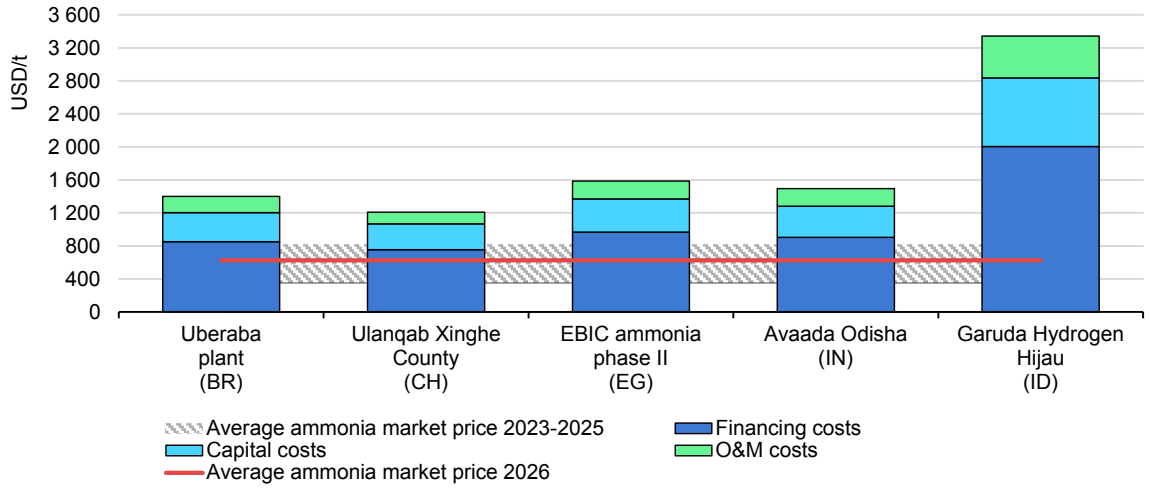
Performance assumptions (in lower-heating value): electrolyser efficiency 63% (China: 60%); H_2 to ammonia efficiency 86%. Capital expenditure (CAPEX) assumptions: Brazil (solar PV USD 661/kW, onshore wind USD 1 296/kW, Haber-Bosch synthesis USD 788/t NH_3); China (solar PV USD 537/kW, onshore wind USD 849/kW, Haber-Bosch synthesis USD 603/t NH_3); Egypt (solar PV USD 948/kW, onshore wind USD 1 327/kW, Haber-Bosch synthesis USD 719/t NH_3); India (solar PV USD 481/kW, onshore wind USD 1 102/kW, Haber-Bosch synthesis USD 567/t NH_3); Indonesia (solar PV USD 554/kW, onshore wind USD 2 455/kW, Haber-Bosch synthesis USD 571/t NH_3); electrolyser USD 2 200/kWe (China: USD 800/kWe); H_2 storage: USD 2 862/kg H_2. Operating expenditure (OPEX) assumptions: onshore wind 2.5% of CAPEX/yr; solar 1.6% of CAPEX/yr; electrolyser 3% of CAPEX/yr; Haber-Bosch synthesis 2.9% of CAPEX/yr.

These cost reductions alone may not be sufficient to bring renewable ammonia prices down to conventional ammonia's by 2030. However, this economic assessment does not capture the growing value governments are placing on supply security and resilience. Recent disruptions to trade routes serving global ammonia, urea and natural gas markets have highlighted the vulnerability of import-dependent economies to supply chain concentration and geopolitical shocks. As ammonia is the primary feedstock for nitrogen fertilisers, supply disruptions can have implications beyond energy markets, affecting agricultural production, food prices and industrial competitiveness.

In this context, renewable ammonia offers a different value proposition. Producing ammonia from domestic wind and solar resources allows countries to reduce dependency on imported fossil fuels while diversifying their fertiliser supply. The economics remain challenging today, but domestic production can

provide greater certainty about supply availability during periods of market disruption and can reduce exposure to volatile international commodity prices. As a result, renewable ammonia production should increasingly be assessed not only against fossil-based ammonia costs, but also against the economic consequences of supply disruptions and import dependence.

Levelised cost of ammonia for selected projects with 13% WACC in 2030



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Notes: WACC = weighted average cost of capital. BR = Brazil. CH = China. EG = Egypt. IN = India. ID = Indonesia. O&M = operations and maintenance. System lifetime: 25 years.

Performance assumptions (in lower-heating value): electrolyser efficiency 63% (China: 60%); H_2 to ammonia efficiency 86%. Capital expenditure (CAPEX) assumptions: Brazil (solar PV USD 518/kW, onshore wind USD 1 259/kW, Haber-Bosch synthesis USD 788/t NH_3); China (solar PV USD 409/kW, onshore wind USD 821/kW, Haber-Bosch synthesis USD 603/t NH_3); Egypt (solar PV USD 722/kW, onshore wind USD 1 282/kW, Haber-Bosch synthesis USD 719/t NH_3); India (solar PV USD 365/kW, onshore wind USD 1 066/kW, Haber-Bosch synthesis USD 567/t NH_3); Indonesia (solar PV USD 392/kW, onshore wind USD 2 314/kW, Haber-Bosch synthesis USD 571/t NH_3); electrolyser USD 1 700/kWe (China: USD 750/kWe); H_2 storage: USD 2 255/kg H_2. Operating expenditure (OPEX) assumptions: onshore wind 2.5% of CAPEX/yr; solar 2% of CAPEX/yr; electrolyser 3% of CAPEX/yr; Haber-Bosch synthesis 2.9% of CAPEX/yr.

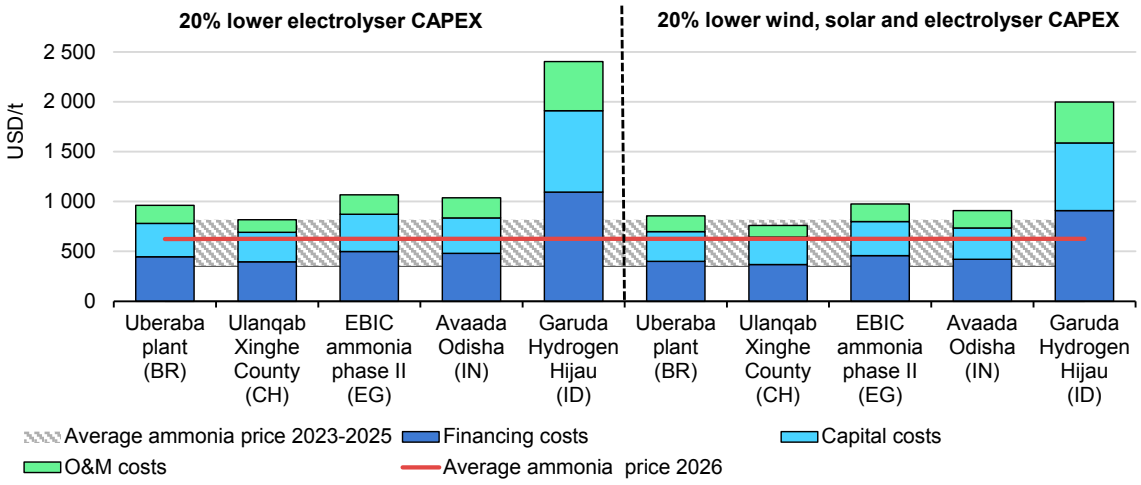
The country analysis suggests that this trade-off could become increasingly favourable over time. In markets with strong renewable resources and improving financing conditions, declining electrolyser and renewable electricity costs could narrow the competitiveness gap substantially by 2030. While renewable ammonia is unlikely to replace conventional ammonia at scale in the near term, it could emerge as a strategic complement to imported supplies, particularly for countries seeking to strengthen energy security, diversify fertiliser supply chains and reduce exposure to geopolitical risks. The question for policy makers is therefore not whether renewable ammonia is the lowest-cost option today, but whether continued cost reductions can reduce the security premium sufficiently to make domestic production an economically justified component of long-term energy and fertiliser security strategies.

However, when we combine a lower WACC of 8% with electrolyser, wind and solar cost reductions, production costs decline significantly, bringing them

closer to fossil-based ammonia market prices in several cases. These production cost declines highlight the importance of improving access to affordable capital alongside continued clean energy technology cost reductions. However, the contribution of each cost-reduction measure differs by country, reflecting variations in renewable resource quality, technology costs and financing conditions.

China and India benefit from comparatively low solar PV, wind and electrolyser costs, and they have the lowest-cost cases of the selected projects. Brazil is also moving closer to competitiveness, thanks to its abundant renewable resources, while Egypt remains more sensitive to financing costs. Indonesia has the smallest overall reductions, largely due to higher onshore wind costs, and continues to be the furthest from fossil-based ammonia market prices.

Levelised cost of ammonia for selected projects with 8% WACC and lower CAPEX values for electrolysers, wind and solar PV in 2030



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Notes: WACC = weighted average cost of capital. BR = Brazil. CH = China. EG = Egypt. IN = India. ID = Indonesia. O&M = operations and maintenance. System lifetime: 25 years.

Performance assumptions (in lower-heating value): electrolyser efficiency 63% (China: 60%); H_2 to ammonia efficiency 86%. Capital expenditure (CAPEX) assumptions: Brazil (solar PV USD 518/kW, onshore wind USD 1 259/kW, Haber-Bosch synthesis USD 788/t NH_3); China (solar PV USD 409/kW, onshore wind USD 821/kW, Haber-Bosch synthesis USD 603/t NH_3); Egypt (solar PV USD 722/kW, onshore wind USD 1 282/kW, Haber-Bosch synthesis USD 719/t NH_3); India (solar PV USD 365/kW, onshore wind USD 1 066/kW, Haber-Bosch synthesis USD 567/t NH_3); Indonesia (solar PV USD 392/kW, onshore wind USD 2 314/kW, Haber-Bosch synthesis USD 571/t NH_3); electrolyser USD 1 700/kWe (China: USD 750/kWe); H_2 storage: USD 2 255/kg H_2. Operating expenditure (OPEX) assumptions: onshore wind 2.5% of CAPEX/yr; solar 2% of CAPEX/yr; electrolyser 3% of CAPEX/yr; Haber-Bosch synthesis 2.9% of CAPEX/yr.

The development of renewable ammonia projects remains uncertain, primarily because demand creation has not kept pace with project announcements. Limited offtake agreements, policy and regulatory uncertainty, and the significant cost premium relative to conventional ammonia continue to delay final investment decisions in many markets. In addition, because ammonia is both a globally traded commodity and a key fertiliser input, project economics remain exposed to trade

disruptions, commodity price volatility and policy uncertainty. As a result, it remains difficult to assess the extent to which announced projects will translate into additional wind and solar PV deployment over the forecast period, with financing conditions, infrastructure readiness and offtake arrangements likely to determine whether projects proceed on schedule.

Annex

Abbreviations and acronyms

ASU	air separation unit
ATR	autothermal reforming
BEV	battery electric vehicle
BF-BOF	blast furnace-basic oxygen furnace
CAES	compressed air energy storage;
CAPEX	capital expenditure
CCGT	combined-cycle gas turbine
CH_3OH	methanol
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
CCS	carbon capture and storage
CCUS	carbon capture, utilisation and storage
CNG	compressed natural gas
CSA	Central and South America
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DAC	direct air capture
DRI	direct reduced iron
DRI-EAF	direct reduced iron-electric arc furnace
EAF	electric arc furnace
EOR	enhanced oil recovery
FC	fuel cell
FCEV	fuel cell electric vehicle
FLH	fuel load hours
FT	Fischer-Tropsch

Glossary

bbl	barrel
bbl/d	barrels per day
bcm	billion cubic metres
bcm/yr	billion cubic metres per year
cm/s	centimetres per second
gCO_2	gram of carbon dioxide
gCO_2/kWh	grams of carbon dioxide per kilowatt hour
GJ	gigajoule
Gt/yr	gigatonnes per year
$GtCO_2$	gigatonne of carbon dioxide
$GtCO_2$/yr	gigatonnes of carbon dioxide per year

See the IEA glossary for a further explanation of many of the terms used in this report.

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