

From shock to strategy:

How the Hormuz crisis is reshaping
the global energy transition

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Introduction

On February 28, 2026, U.S. and Israeli strikes on Iranian nuclear and military infrastructure triggered the effective closure of the Strait of Hormuz, the world's most critical energy chokepoint. Within days, crude oil transit through the Strait had fallen from 20 million barrels per day to less than 4 million, liquified natural gas (LNG) flows to Asia were severely disrupted, and energy markets entered the most severe supply crisis since the 1973 Arab oil embargo.

I wrote this global energy markets overview for the 28th edition of WEMO during the Hormuz Strait shock, and I used it as the starting point for my analysis.

The crisis has made energy sovereignty a first-order political priority in many large economies. I believe that the correct strategic response is to accelerate the energy transition, but on terms that prioritize realistic sovereignty alongside decarbonization, and that include cost and reliability.

Four analytical threads run through the nine chapters that follow.

First, the “triple test” for clean energy: a source must be non-fossil, non-emitting, and sovereign—that is, producible and operable without dependence on a foreign state. Wind and solar and associated stationary batteries pass the first two tests but fail the third mainly at the construction stage because China is dominant on production of clean technologies (photovoltaic, or PV, wafers/cells/modules, wind turbines, and batteries), and processing of strategic minerals including rare earths. The ways to improve the “clean energies” value chain sovereignty in Europe without increasing costs significantly and depriving European customers from Chinese technical innovations are explored in this report. Nuclear, geothermal, and hydropower pass all three tests. The further deployment of large nuclear plants alongside small modular reactors (SMRs) is analyzed, as well as possible geothermal generation expansion thanks to new technologies as enhanced geothermal systems (EGSs).

Second, the real cost of intermittency: as renewable penetration rises, the system cost of integrating variable generation is significantly higher than its plant-level levelized cost of electricity (LCOE). Grid reinforcement and backup capacity investments, along with increased balancing service needs, can double the real cost of solar and wind electricity generation at high penetration levels. In weak or poorly managed grids, their massive and intermittent character can lead to blackouts.

Third, the technology landscape: hydrogen has underdelivered against its promise, geothermal has been under-deployed against its potential, and fusion remains a long-term option. Regarding future clean technologies there are no silver bullets, present technologies must be deployed at scale and increased efforts in R&D (that are often a very small portion of industrial deployment costs) are needed to improve existing technologies, for example by developing new materials.



Massive deployment of generative AI and physical AI will bring improvement in grids and plant generation at all stages of their lifetime.

Fourth, on electricity consumption: data centers have emerged as the largest demand driver in global electricity markets with exponential growth projections. However, data center growth will increasingly be constrained by the grid's ability to accommodate new connections, resulting in lengthy interconnection queues. Sustained solutions include off-grid generation when there is enough space to build renewables associated with battery parks, nuclear generation plants, or smaller size fuel cells. In the U.S., new gas turbine construction is growing fast, but it is not a sustained solution. In certain locations, negative public opinion is rising, resulting most notably from the fear of retail price increases. Finally other factors, such as financing and regulations, will limit data center expansion. Nevertheless, data center electricity demand is poised to grow fast with significant repercussions on the grid.

This WEMO 2026 overview closes with seven recommendations for energy companies and governments, including the electrification imperative, grid investment and grid flexibility needs, nuclear deployment, more sovereign supply chains development, and the climate change adaptation imperative. The Hormuz crisis will probably end, but the structural vulnerabilities it has exposed will not resolve themselves without deliberate policy action. The window to act is open.

I wish you a pleasant read.



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01

The 2026 energy shock



The U.S.-Israel war against Iran, that begun on February 28, 2026, triggered the effective closure of the Strait of Hormuz, the world's most critical energy chokepoint. The Strait, barely 50 kilometers wide between Iran and Oman, is the passage for approximately 20 million barrels per day (Mb/d) of oil (20% of global petroleum trade) and approximately 75 million tons per annum (Mtpa) of LNG (~20% of global LNG trade)

1.1 The conflict chokepoint: Strait of Hormuz

The effective closure of the Strait of Hormuz since March 4, 2026 represented the most severe supply disruption in recorded history. Crude transit dropped from 20 Mb/d to 3.8 Mb/d. As a result, 84% of crude destined for major Asian markets was missing. The crisis simultaneously impacted crude oil, LNG, and refined products supply.

Supply losses

- Strait closure: transit fell from 20 Mb/d to just 3.8 Mb/d by early April, an effective loss of ~16 Mb/d.
- Gulf producer output was cut: Saudi Arabia output fell from 10.4 Mb/d to 7.25 Mb/d; Iraq from 4.57 Mb/d to 1.57 Mb/d; Kuwait from 2.54 Mb/d to 1.19 Mb/d.
- Damaged infrastructure: Saudi Arabia's Ras Tanura (550,000 b/d) temporarily halted; UAE Ruwais refinery was damaged.
- Iran's own losses: pre-war exports of ~1.5 Mb/d via Kharg Island dropped to zero.
- Cumulative toll: by mid-June, analytics firm Kpler estimated the war had cost the world 1.15 billion barrels of lost oil supply, with none flowing out of the Middle East for nearly four

months; the IEA's own strategic reserves fell to their lowest level since 1990, and the U.S. Strategic Petroleum Reserve (SPR) hit a 43-year low.¹

Supply additions were small compared to the losses

- IEA emergency release: 400 million barrels (mb), the largest in the agency's 50-year history (vs 182 mb at the beginning of the Russia/Ukraine war). The U.S. contributed 172 mb from its SPR.
- Venezuela: U.S. Treasury authorized sales from Petróleos de Venezuela (PDVSA), the state-owned oil and natural gas company. Best case: +250,000 b/d by the end of 2026.
- IEA confirms the scale: Gulf output remained 14.4 Mb/d below pre-war levels as of May, with global oil supply for 2026 now projected to average 102.2 Mb/d (a decline of 3.9 Mb/d) even as flows gradually resumed from June; 2026 demand is now projected to decline 420,000 b/d to average 104 Mb/d.²

1.2 Comparison of hydrocarbons supplies severity

The Iran war creates three overlapping crises regarding supply of crude oil, LNG, and refined products. The LNG shock is structurally more severe. Except in the European Union (EU), there is no strategic gas reserve equivalent to the oil SPR, most LNG terminals already operate at near-full capacity, and Qatar's 3–5-year repair timeline means the market remains structurally tense after any ceasefire.³

Following the sharp reduction in Russian gas supplies after the 2022 invasion of Ukraine, the EU introduced a regulation which mandates that all member states fill their underground gas storage facilities to at least 90% of capacity, roughly 3,750 billion cubic feet (bcf),

before November 1 of each year. However, as the Hormuz crisis started at the end of the winter when the reserves were at a low point, European seasonal gas purchasing to refill the reservoirs has amplified price volatility.



¹International Energy Agency, Oil Market Report, May 2026 (13 May 2026), Paris; David Goldman, "More than 1 billion barrels of oil have gone missing," CNN Business, 19 June 2026, citing Kpler data.

²International Energy Agency, Oil Market Report, May 2026 (13 May 2026), Paris; David Goldman, "More than 1 billion barrels of oil have gone missing," CNN Business, 19 June 2026, citing Kpler data.

³S&P Global, ICIS, Kpler and Rystad — 2026 global LNG supply outlook cut by up to 35 Mtpa.

Table 1 — Severity comparison of the three overlapping supply crises⁴

Dimension	Crude oil	LNG (gas)	Refined products
Volume missing	~14–16 Mb/d	~10 bcf/d (20% of trade)	~4.8 Mb/d total
Strategic buffer	Yes (IEA SPR)	No (except EU gas stocks)	Partial
Price shock	+25–40% Brent	+96–143% Asia	+100% Diesel/ Jet
Recovery time	Weeks to months	3–5 years (damaged plants)	Months

1.3 Crude and gas prices—regional variations

Brent crude reached an intraday 52-week high of \$120.88 on April 30, but never spiralled to the \$150–180/barrel scenarios that some banks had warned of in the early weeks of the war, thanks in large part to China's behavior. The Chinese buyers effectively cushioned the global oil market by utilizing China's massive SPR, estimated at nearly 1.4 billion barrels. Instead of panic-buying, they stopped global spot market acquisitions and drew down from their domestic inventories, preventing oil prices from spiralling to the levels initially feared.^{5,6,7,8}

Following the ceasefire framework agreed on June 14, 2026, and the phased reopening of the Strait⁹, Brent fell back below \$80/barrel by late June—more than 30% lower than its March peak.

⁴WEMO 2026 analysis based on IEA Oil Market Report (April 2026); Vortexa / Kpler Analytics; Global LNG Hub.

⁵<https://www.brookings.edu/articles/from-chokepoint-to-crisis-the-strait-of-hormuz-and-global-oil-markets/>

⁶Vortexa / Kpler Analytics. (2026). Seaborne Crude Flows and Shadow Inventories: How Chinese Commercial and Strategic Stockpiles Buffered the 2026 Supply Disruption.

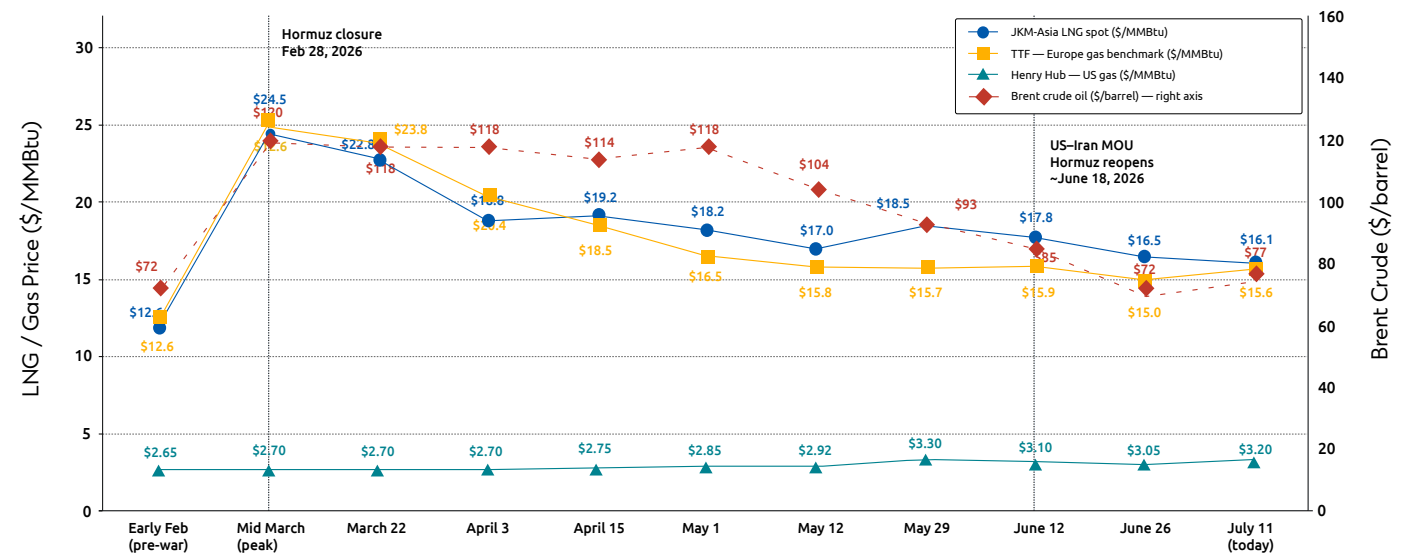
⁷International Energy Agency (IEA). (2026). Oil Market Report: Global Inventory Dynamics and Geopolitical Shock Absorbers. Paris.

That relief proved short-lived: on July 7–8, President Trump declared the ceasefire “over,” ordered fresh strikes on Iranian targets, threatened to reimpose the naval blockade, and seize Kharg Island, Iran's main export terminal, sending oil prices up more than 4% in a single session¹⁰. J.P. Morgan revised its outlook accordingly, projecting Brent to average \$86/barrel in Q3 and \$80/barrel in Q4 2026, and exiting the year near \$78/barrel¹¹. This is a marked de-escalation from its earlier worst-case scenarios, but a reminder that the crisis remains unresolved.

The most striking divergence has been in gas markets. While the Asian Japan/Korea Marker (JKM) and the European Title Transfer Facility (TTF) spiked sharply, U.S. Henry Hub remained broadly unchanged, giving U.S. industrial companies a significant competitive advantage and directly benefiting U.S. LNG exporters.

Figure 1

LNG and Brent crude price variations by region, February–July 11, 2026¹²



Sources: EIA; ICIS; Wood Mackenzie; Global LNG Hub / JOGMEC weekly updates (May–July 2026); JFX; CNBC/Reuters oil price reporting (May–July 2026)

Note: JKM = Japan Korea Marker (\$/MMBtu); post-May 12 points are weekly assessed levels compiled from Global LNG Hub and market reporting, not exchange settlement prices.

⁸US Energy Information Administration, “Crude oil and petroleum product prices increased sharply in the first quarter of 2026,” Today in Energy, 2026; EIA, Europe Brent Spot Price FOB (daily), 9 March and 30 April 2026 data points.

⁹US, Iran reach deal to extend ceasefire, open strait,” Axios, 14 June 2026; “US-Iran ‘peace deal’ announced; Trump says Strait of Hormuz reopening,” Al Jazeera, 14 June 2026; CENTCOM announcement of naval blockade removal, 18 June 2026.

¹⁰Matt Egan, “Trump is playing with economic fire by calling the peace deal with Iran ‘over,’” CNN Business, 8 July 2026, <https://edition.cnn.com/2026/07/08/business/iran-oil-trump-strait-of-hormuz/>; “U.S. military completes latest strikes on Iran after Trump says ceasefire is ‘over,’” NBC News, 8 July 2026.

¹¹J.P. Morgan Research, oil price scenarios cited in “JP Morgan Warns Oil Could Hit \$120 if Hormuz Stalemate Drags Into July” and “JP Morgan Sees \$150 Oil if Hormuz Remains Closed Through Mid-May,” OilPrice.com, 2026; revised Q3–Q4 2026 Brent forecast per “JPMorgan resets oil price target for rest of 2026,” TheStreet, June 2026.

¹²Trading Economics; Global LNG Hub; CNBC; LNG Price Index.



1.4 Oil demand and GDP impact

The demand shock has been swift and severe. The IEA's pre-crisis forecast in February 2026 had projected global oil demand growth of +850,000 b/d for the year; its April revision flipped that to -80,000 b/d, a 930,000 b/d decrease in eight weeks. The Q2 2026 quarterly forecast of -1.5 Mb/d represents the sharpest single-quarter contraction since COVID-19. The macroeconomic implications are comparably important: in July the IMF cut its baseline global growth forecast to 3.0% for the year, citing the lingering effects of the energy shock even as an AI-driven investment boom partly offset the growth slowdown. The feared "close call for a global recession" has, for now, been avoided. The Middle East and Central Asia suffered the biggest shock¹³ as their growth forecast there is downgraded to 1.9%.

That said, the same oil price surge a decade earlier would have hit harder. A fundamental structural shift has taken place in the relationship between economic output and energy consumption: the world now requires substantially fewer fossil fuels to generate a unit of GDP than it did in previous decades. Across most industrialized economies, the oil intensity of GDP has fallen by roughly 50% since the Gulf War of 1990.

1.5 Regional breakdown

Asia: The epicenter

84% of crude oil and 83% of LNG shipped through the Strait of Hormuz is bound for Asian markets. China, India, Japan, and South Korea account for 69% of all crude flows. At the beginning of the war, Japan had 254 days of strategic oil reserves.

The situation was different on the LNG side as Japan had only ~19 days of LNG imports on hand.

¹³International Monetary Fund, World Economic Outlook Update, July 2026; "IMF cuts 2026 world growth forecast, citing Iran war fallout," Al Jazeera, 9 July 2026.

¹⁴World Bank/UN Comtrade (WITS), Japan liquefied natural gas imports by partner country, 2024 data; IEEFA, Australian Gas and LNG Tracker, 2026.

Even though Australia is Japan's largest LNG supplier by far¹⁴, Japanese gas prices still surged because LNG is priced as one fungible global market. Qatar alone used to supply close to 20% of the world's LNG, and its loss through Hormuz pushed Asian and European buyers into a bidding war for the same non-Hormuz cargoes. With only ~19 days of LNG in storage and no strategic buffer comparable to its oil reserve, Japan had to keep buying spot cargoes at whatever price cleared the market. This resulted in an increase of the JKM benchmark well above pre-war levels.¹⁵ This price increase passed straight through into Japan Electric Power Exchange (JEPX) electricity prices given gas and coal's dominant role in the generation mix (see figure 2).

Middle East: Direct victim

Gulf oil production dropped by at least 10 Mb/d collectively by March 12. 70% of the region's food imports were disrupted; Iranian strikes on desalination plants—the source of 99% of drinking water in Kuwait and Qatar—have worsened the crisis.

United States: A relative winner

Domestic production insulates the U.S. from physical shortages. U.S. LNG exporters are benefiting directly from the crisis: Hormuz disruption tightens global LNG markets, widening the spread between Henry Hub (~\$3.20/million British thermal units, or MMBtu¹⁶) and European TTF or Asian JKM (~\$20+/ MMBtu at the peak).

Europe: Asymmetric shock

EU strategic oil reserves cover ~90 days of net imports and Europe imports only ~7% of its oil from Saudi Arabia and ~5.7% from Iraq. On the gas and electricity prices side, the shock is asymmetric: Italy and the UK are most exposed (gas-heavy power mix), while France and Spain are relatively protected (nuclear and renewables).

¹⁵"Iran War Upends LNG Market and Jolts Gas Prices," OilPrice.com, 2026; S&P Global Commodity Insights, "Asian LNG markets assess supply risks amid escalating Israel-Iran conflict," 13 June 2026.

¹⁶MMBTU: Million of British Thermal Units. 1MWh=3.412 MMBTU

1.6 EU electricity price divergence

The Strait of Hormuz closure induced a decoupling in European electricity markets. Peak volatility in mid-March 2026 revealed France and Spain to be better insulated due to nuclear baseload and solar, while Germany and Italy were exposed to high gas-to-power dependency. The crisis confirms that electricity mix composition is a determinant of energy cost resilience.

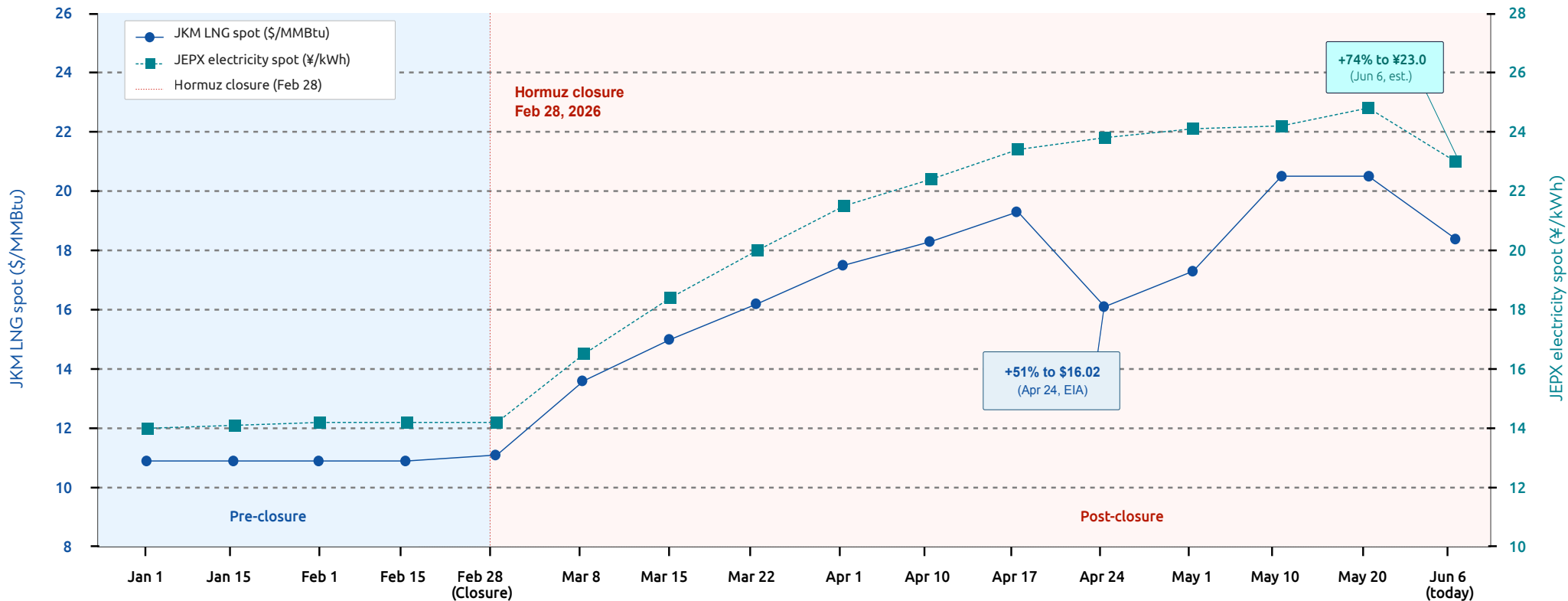
1.7 Japan: LNG exposure despite partial nuclear restart

Japan faces unique isolation risks as an energy island. Despite the partial restart of nuclear plants, Japan's heavy reliance on LNG exposes it disproportionately to the Hormuz disruption. The crisis has reinforced Japan's accelerated nuclear restart program and domestic renewables targets.





Figure 2

Japan LNG (JKM) vs. electricity spot (JEPX) prices since the Strait of Hormuz closure, January–June 2026¹⁷

Sources: EIA (Apr 29, 2026) · IEEFA (Mar 27, 2026) · Wood Mackenzie (Mar 11, 2026) · Global LNG Hub (Jun 1, 2026) · JEPX

Note: JKM = Japan-Korea Marker (Asia LNG benchmark), JEPX post-Apr data estimated from published trajectory.

¹⁷EIA (29 Apr 2026); IEEFA (27 Mar 2026); Wood Mackenzie (11 Mar 2026); Global LNG Hub (1 Jun 2026); JEPX.



1.8 Iran played its Hormuz card, but it can only use it once.

Since the Russian invasion of Ukraine and the Houthi attacks on tankers in the Bab el-Mandeb Strait, global energy markets have been fragmenting as trade flows once governed by cost optimization are now dictated by politics and security. The Hormuz crisis has taken this further. Tehran attempted to monetize the Hormuz Strait while tolling would be illegal under international law.

The sequence of events since February has borne this dynamic out. A ceasefire framework, agreed on June 14, 2026, and formalized in a memorandum of understanding three days later, provided for a phased reopening of the Strait and the lifting of the U.S. naval blockade.¹⁸ The agreement lasted only until July 7–8, when the U.S. declared the ceasefire “over”.¹⁹

The episode has also exposed a second crisis: OPEC’s own struggle for relevance. The United Arab Emirates left the 59-year-old cartel on May 1, 2026, frustrated with production quotas that constrained its spare capacity,²⁰ as well as the episodes of reopening of the Strait, which has revived old disputes over who recaptures lost market share. Vikas Dwivedi, global oil and gas strategist at Macquarie Group, has warned that if following the Hormuz crisis end, Saudi Arabia would opt to flood the market rather than defend prices, OPEC+ discipline could collapse—a scenario he says could send crude toward \$40/barrel, barely months after \$120 oil.^{21 22} That scenario illustrates how quickly the crisis could flip from a supply-scarcity shock to a demand-and-market-share problem.

History suggests that acute energy shocks, however disruptive, tend to trigger structural responses that permanently reduce the vulnerability they exposed to. The 1973 Yom Kippur War and the subsequent OPEC oil embargo quadrupled oil prices and caused widespread

shortages. However, it also catalyzed the development of North Sea oil and gas production and France’s nuclear program launch, decisively reducing European dependence on Middle Eastern oil.

Three decades later, rising demand and tightening supply—with OPEC playing a central role—triggered the oil price surge of the mid-2000s, driving prices from \$20–30 per barrel to nearly \$140 in 2008. Combined with advances in horizontal drilling and hydraulic fracturing, these sustained high prices made U.S. shale commercially viable, transforming America into the world’s largest oil and gas producer and reshaping global supply geography.

The Hormuz crisis is likely to prove the third such inflection point. As energy analyst Leslie Palti-Guzman observes: “The silver lining is that the Strait of Hormuz is a one-time source of leverage for Iran. Now that Tehran has shown it can effectively close the Strait, countries that depend on it will diversify their routes and energy supplies at all costs. It may take months; it may take years — but I think we have seen the peak of Iran using the Strait as a weapon.”²³

1.9 Structural diversification: Bypassing the Strait

This restructuring is not theoretical—it is already under construction. Three projects illustrate how quickly producers and buyers are re-routing around the Strait:

- United Arab Emirates and the West-East Pipeline: Abu Dhabi National Oil Co. (ADNOC) is fast-tracking a new pipeline that will double export capacity from Habshan to the port of Fujairah on the Gulf of Oman just beyond Hormuz. It runs alongside the existing 380-kilometer Abu Dhabi Crude Oil Pipeline (ADCOP), which carries 1.5 Mb/d and has been operating since 2012).

The new line was roughly 50% completed by May and is due onstream in 2027.²⁴

- The Israeli prime minister and energy minister have proposed a roughly 700-kilometer pipeline linking Gulf crude to Eilat, where it would connect to the existing Eilat-Ashkelon (Trans-Israel) Pipeline for export to Europe via Mediterranean tankers. The project remains at the proposal stage, contingent on Saudi and wider Gulf region political buy-in.²⁵
- TotalEnergies and Pacific LNG: On Mexico’s Baja California coast, TotalEnergies shipped its first LNG cargo to Asia in July from the ECA LNG Phase 1 terminal, where it holds a 16.6% stake and a 1.7 Mtpa offtake agreement. Fed by U.S. Permian gas, the terminal reaches Asian buyers via the Pacific, the shortest maritime route to Asia, and one that never touches the Strait of Hormuz or the Gulf at all.²⁶

Combined with Saudi Arabia’s existing 1,200-kilometer East-West pipeline to Yanbu on the Red Sea, these routes will not replace the Hormuz Strait, but they materially shrink the share of crude oil, LNG, and refined products that transit through it.

¹⁸US, Iran reach deal to extend ceasefire, open strait,” Axios, 14 June 2026; “US-Iran ‘peace deal’ announced; Trump says Strait of Hormuz reopening,” Al Jazeera, 14 June 2026; CENTCOM announcement of naval blockade removal, 18 June 2026.

¹⁹Matt Egan, “Trump is playing with economic fire by calling the peace deal with Iran ‘over,’” CNN Business, 8 July 2026, <https://edition.cnn.com/2026/07/08/business/iran-oil-trump-strait-of-hormuz/>; “U.S. military completes latest strikes on Iran after Trump says ceasefire is ‘over,’” NBC News, 8 July 2026.

²⁰“The UAE is leaving OPEC on Friday,” NPR, 28 April 2026; “UAE’s departure from the OPEC oil cartel is not without precedent. Who could be next?” CNBC, 29 April 2026.

²¹Vikas Dwivedi, global oil and gas strategist, Macquarie Group, quoted in Krystal Hur, “Trump is gaining surprising leverage over Iran,” CNN Business, 7 July 2026, <https://edition.cnn.com/2026/07/07/business/iran-trump-oil-price-supply/>.

²²Krystal Hur, “OPEC is in a struggle for its survival. It could mean \$40 oil,” CNN Business, 6 July 2026, <https://www.cnn.com/2026/07/06/economy/the-fight-for-the-future-of-opec-begins-now/>.

²³https://lesliepaltiguzman.substack.com/p/iran-used-its-one-time-hormuz-card?utm_source=post-email-title&publication_id=3743321&post_id=201151692&utm_campaign=email-post-title&isFreemail=true&rs=5ra1xl&triedRedirect=true

²⁴“UAE to accelerate oil pipeline project to bypass Strait of Hormuz,” Al Jazeera/Reuters, 15 May 2026; “UAE says new pipeline that will bypass Strait of Hormuz is nearly 50% complete,” CNBC, 20 May 2026.

²⁵“Israeli PM Proposes Mediterranean Pipeline to Bypass Strait of Hormuz as Iran Mulls Tolls,” Pipeline Technology Journal, 2026; “Energy Minister Cohen proposes oil pipeline to bypass Hormuz,” The Jerusalem Post, 2026.

²⁶“Mexico: TotalEnergies Ships to Asia the Very First Cargo Produced by the ECA LNG Plant,” TotalEnergies press release, July 2026; “TotalEnergies Ships First LNG Cargo from Mexican Pacific Coast to Asia,” Rigzone, 9 July 2026.



02

Energy sovereignty





The Hormuz closure has triggered a reassessment of what energy security means. This Outlook introduces a triple classification framework that moves beyond the conventional focus on clean electricity (criteria 1 and 2) to include sovereignty (criterion 3).

**Criterion 1:
Non-fossil**

Does generating electricity require burning fossil fuels? Fossil fuels are finite, price-volatile and geopolitically concentrated.

**Criterion 1:
Non-emitting**

Does generating electricity release CO₂ or greenhouse gases (GHGs), including full lifecycle emissions from manufacturing, mining, and construction?

**Criterion 1:
Sovereign**

Can a country produce, operate, and maintain this energy source independently, without depending on a foreign supplier for fuel, components, or technology?

The critical finding: Only hydropower, nuclear and geothermal satisfy all three criteria simultaneously. Wind and solar satisfy criteria 1 and 2 but fail on criterion 3 as China controls more than 80% of solar manufacturing and about 60% of wind turbine production globally. A country deploying renewables at scale replaces dependence on Gulf fossil exporters with dependence on Chinese industrial production.

2.1 The wrong temptations: Coal and Russian gas

The Hormuz crisis has generated a set of short-term policy reflexes that, if acted upon, would be damaging in the long term. Two temptations stand out: returning to coal, when it is regionally sovereign, and postponing the phase-out of Russian gas. Both are understandable responses to energy price shocks. Both are strategic mistakes.

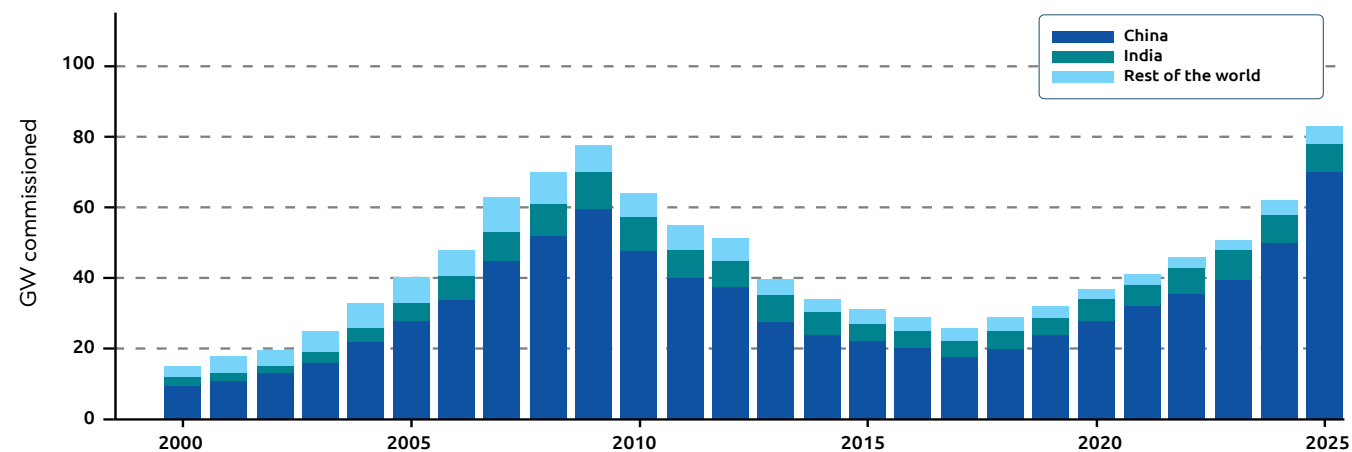
Temptation 1: Coal as a “sovereign” response

Coal is undeniably sovereign in several major economies. The U.S., China, India, Poland and Australia control large domestic reserves and do not depend on imports. This could make it politically attractive in the current crisis.

New coal fired electricity plant capacity continues to grow as shown in Figure 3. It hit a 10-year record in 2025, driven almost entirely by China and India, with approximately 84 GW of new capacity brought online—comparable to the entire installed nuclear capacity of the United States.

Figure 3

New coal capacity commissioned per year (GW, 2000–2025).²⁷



Source: Global Energy Monitor — Global Coal Plant Tracker (May 2025).

²⁷Global Energy Monitor — Global Coal Plant Tracker (May 2025); Les Echos, May 2025.

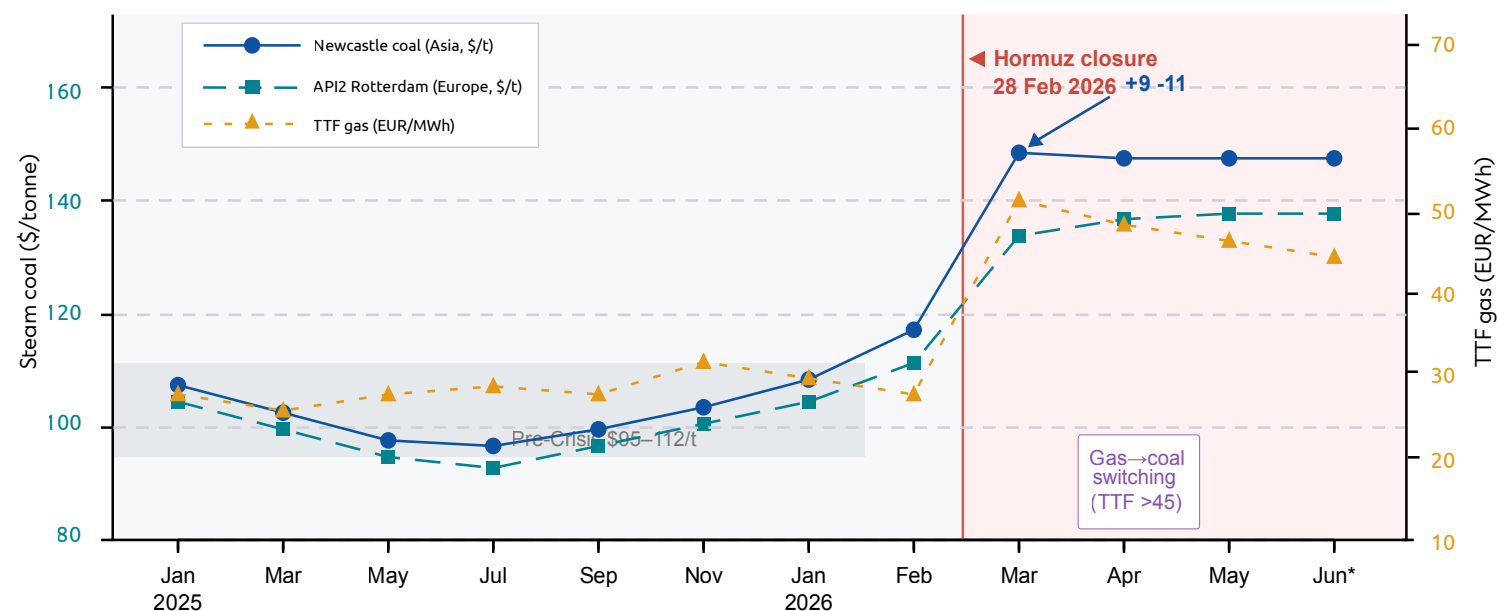


Why coal is a trap, not a solution. Coal satisfies criterion 3 (sovereign) but fails criteria 1 and 2 because it burns fossil fuel and emits CO₂. Beyond that, it does not deliver the price insulation one might hope for.

Steam coal prices are structurally correlated with natural gas prices because coal is the primary substitute fuel for power generation when gas becomes expensive. When the Hormuz closure drove European TTF gas up 88% to €53/MWh in March 2026, some utilities across Europe and Asia switched to coal, driving the Newcastle coal benchmark up 9–11% to \$150/tonne and API2 Rotterdam coal quotation up to \$135–139/tonne—gains not seen since the 2022 Russian gas crisis. As illustrated below, both coal benchmarks tracked the TTF gas spikes closely. A country turning to coal in response to an oil or gas price shock does not escape the energy price crisis.

The only scenario in which a return to coal would be defensible is one where carbon capture and storage (CCS) is cost-effective and deployed at scale alongside coal-fired plants, making coal “clean” in addition to sovereign. That scenario does not exist today: CCS costs remain \$80–120/tonne CO₂ at scale, no large-scale coal-CCS project is operating commercially, and CCS efficiency penalties reduce net plant output by 15–25%. Until cost-effective CCS is demonstrated at commercial scale (which could arrive in China), coal is sovereign but neither clean nor price-insulating.

Figure 4

Steam coal and European gas prices before and after the Hormuz closure, January 2025–June 2026²⁸

Jun 2026 provisional. Sources: Trading Economics; EIA; Bloomberg/OilPrice.com; WEMO analysis.

Coal prices (Newcastle Asia and API2 Rotterdam, left axis) tracked the TTF gas spike (right axis) after the Hormuz closure on February 28, 2026, confirming coal’s role as a gas substitute rather than a price shield. **Sources: Trading Economics; EIA; Bloomberg/OilPrice.com.**



Temptation 2: Postponing the ban on Russian gas

The United Kingdom's decision in May 2026 to delay its planned phase-out of Russian LNG purchases—citing supply security concerns in the context of the Hormuz crisis—is the most prominent recent example of this second temptation. The U.K. government justified the delay as a temporary bridge measure, arguing that sanctioning Russian LNG while the Strait of Hormuz is effectively closed would expose British industry and households to unacceptable price spikes. Similar pressures were visible in central European markets, such as Hungary and Slovakia, which never fully severed pipeline gas ties with Russia.

- **The strategic contradiction:** Russian gas fails all three tests of the framework introduced in this chapter—and it funds a government at war with a European neighbor.
- **The U.K. precedent:** By publicly reactivating Russian LNG as a “bridge” option, the U.K. signals to global markets that European energy policy can be reversed under pressure, undermining the credibility of future phase-out commitments and reducing the investment incentive for alternative infrastructure.
- **The alternative already exists:** The U.S., Qatar (once repairs are complete), Norway, and Australia collectively have sufficient LNG export capacity to replace Russian volumes. The bottleneck is European regasification terminals capacity (though Floating Storage and Regasification Units can be built in 2–3 years) not a long-term supply shortage.

Policy conclusion:

The correct response to the Hormuz shock is to accelerate the clean and sovereign energy transition. Coal and Russian gas are short-term analgesics that defer the structural reform. The countries that will emerge strongest from this crisis are those that engage and commit to large electrification plans.

2.2 Clean energy cost and sovereignty comparative

Table 2 — LCOE and sovereignty assessment by energy source²⁹

Energy source	LCOE (\$/MWh)	Build time	Sovereign?	Intermittent?
Onshore wind	\$24 – \$75	1 – 2 years	No (China turbines)	Yes
Utility solar PV	\$28 – \$117	6 – 18 months	No (China panels)	Yes
Offshore wind	\$72 – \$140	3 – 5 years	Partial (EU capacity/China)	Reduced
Large hydro	\$47 – \$68	5 – 15 years	Yes (site-limited)	No
Nuclear	\$62 – \$220	6 – 15 years	Largely yes	No
Geothermal	\$50 – \$350	5 – 10 years	Yes	No

The table above reflects LCOE figures for new-built plants. Three important qualifications apply. First, the LCOE of existing nuclear plants in lifetime extension is approximately \$60/MWh, making refurbishment and life extension, where safety conditions are met, one of the most cost-competitive options available today. Second, the LCOE figures for wind and solar do not capture the additional system costs generated by their inherent intermittency, such as grid balancing, backup capacity, transmission reinforcement and storage. These costs can be substantial when variable renewables reach a high share of the electricity mix. They are examined in detail in section 2.4. Third, geothermal requires up-front geological risk-taking; with the present drilling technologies, its potential is limited (see pages 19–20).

²⁹Own analysis based on Lazard, Levelized Cost of Energy+ (2025); IRENA, Renewable Power Generation Costs in 2024; IEA, Projected Costs of Generating Electricity (2025 update).





Policy conclusion:

Only hydropower (where geography allows), nuclear, and geothermal (with limited potential) satisfy all three criteria simultaneously. The Hormuz stress test has confirmed this. The countries with the highest energy security scores (i.e., Norway with hydropower and France with nuclear) are those least affected by the crisis.

2.3 Solar and wind: Achievements and limits (2020–2025)

Wind and solar power have achieved a genuine industrial revolution over the past five years. Global solar PV capacity more than tripled, from 714 GW in 2020 to 2,350 GW in 2025, while the LCOE for utility-scale solar fell by 51%, from \$57/MWh to \$28/MWh. Today, at the plant level, solar is the world's cheapest source of electricity plant. Wind capacity grew from 733 GW to 1,250 GW, an increase of 71%. Wind capacity factors (CF)³⁰ are higher than solar with an offshore wind CF range of 35–55%, compared to 25–45% for onshore wind and 10–25% for PV solar.³¹ Roughly speaking, it means that replacing one watt of conventional fossil electricity generation capacity requires the installation of roughly two watts of wind power and up to four watts of solar PV capacity.

In the last two years, offshore wind has encountered a few difficulties:

Supply chain and macroeconomic shocks: Offshore wind has suffered from severe supply chain bottlenecks, soaring material costs, and rising interest rates, leading developers to cancel or renegotiate legacy power contracts.

Heavy losses and project delays: European offshore wind manufacturers (e.g., Siemens Gamesa, Vestas, and developer Ørsted) have experienced both losses and delays, largely due to the too rapid scale-up of next-generation 15 MW+ turbines, which has led to quality defects and rising warranty costs.³²

Policy and subsidy retractions: In the U.S., the industry faces added friction due to reduced federal clean energy subsidies.

Project pauses and financial stress: These combined economic pressures have forced project delays, multi-billion-dollar write-downs, and large projects pauses.



³⁰The capacity factor represents the ratio of the actual electricity generated by a power plant over a given period to its maximum potential output if it operated continuously at full nameplate capacity

³¹Bolson et al., 2023, IRENA

³²Siemens Gamesa quality issues and provisions: Siemens Gamesa, Vestas, Ørsted Updates <https://weatherguardwind.com/siemens-gamesa-vestas-orsted-updates/>

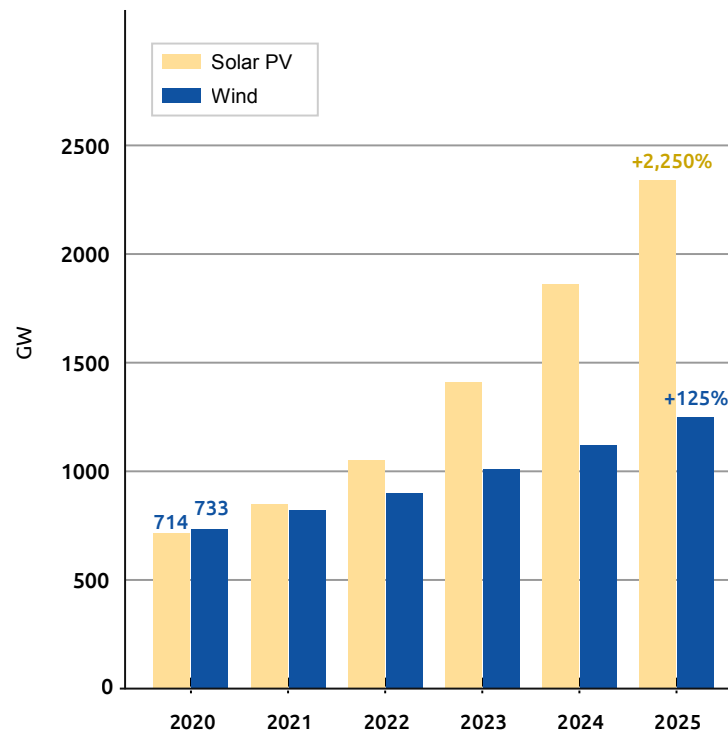


Together, solar and wind generated approximately 5,900 terawatt-hours (TWh) in 2025, up from 2,412 TWh in 2020—an increase of 145%. These sources now cover roughly 15% of global electricity demand.

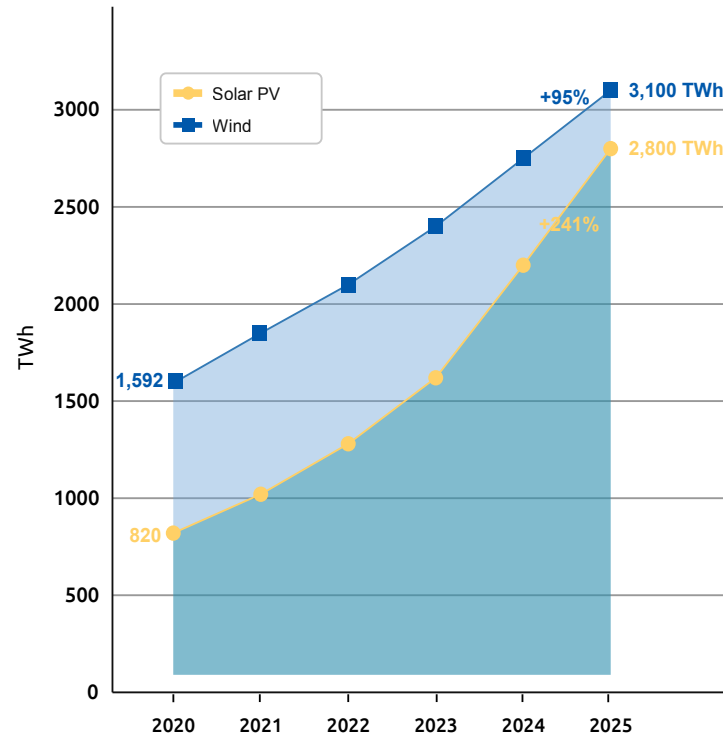
Figure 5

Solar PV and wind installed capacity, electricity generation and solar LCOE trajectory, 2020–2025³³

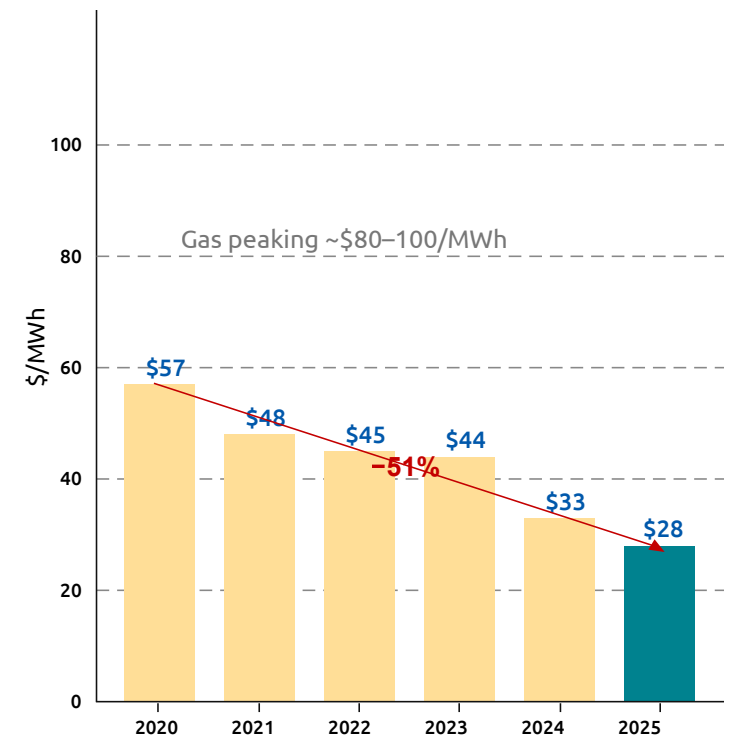
Installed Capacity (GW) 2020–2025



Electricity Generation (TWh) — 2020–2025



Utility Solar PV LCOE (\$/MWh) — 2020–2025



Sources: IRENA Renewable Capacity Statistics 2025; IEA World Energy Statistics 2025; BNEF Solar LCOE Index Q1 2025. Onshore wind LCOE global average: \$24–50/MWh (2025).

³³IRENA Renewable Capacity Statistics 2025; IEA World Energy Statistics 2025; BNEF Solar LCOE Index Q1 2025. Onshore wind LCOE global average: \$24–50/MWh (2025).



Despite this success, three structural limits remain. First, the cost of solar and wind continues to fall at the module and turbine level, while the system costs (e.g., grid connection, backup capacity, storage, and land) are increasing. Second, the pace of deployment has caused solar curtailment and negative electricity prices to surge in markets with high penetration (see section 2.4). Third, and most critically, as highlighted by the Hormuz crisis, both technologies fail the sovereignty test: China controls over 80% of all solar manufacturing stages and approximately 60% of global wind turbine production. This means that the energy dependency on fossil fuels is partly replaced by industrial dependency on China.

Bottom line: Solar and wind are now the lowest-cost source of new electricity generation in most markets, and their five-year deployment record is unmatched in energy history. But they require firm backup, grid reinforcement, and local supply chain investment to deliver truly sovereign, reliable clean power to the benefit of end customers.

Clean energy sovereignty challenges in the EU and solutions

Building industrial sovereignty for Europe's clean energy transition is a complex balancing act. Unlike natural gas or coal, which require continuous import from volatile regions to keep plants running, wind turbines, solar panels, and, to a certain extent, batteries are sovereign assets once installed. They produce localized, independent power regardless of ongoing global trade dynamics. However, the initial equipment and the critical raw materials—particularly metal and rare earth elements and lithium-ion battery inputs (as anodes)—are overwhelmingly dominated by China.

To address this, the EU has introduced legislative frameworks like the Net-Zero Industry Act (NZIA) and the proposed Industrial Accelerator Act (IAA), which aim to localize at least 40% of Europe's clean tech manufacturing by 2030 using non-price resilience criteria in public tenders and subsidy schemes. For example, the June 2026 very large French offshore wind tender for 11 offshore wind projects totaling ~10 GW³⁴ introduces, for the first time, eligibility and scoring criteria tied to European supply chain resilience under the NZIA, effectively requiring bidders to source a share of components from European (notably French) manufacturers.

Yet, achieving this sovereignty must be progressive. Imposing immediate, rigid protectionist walls would trigger devastating green energy price shocks and deprive EU citizens of needed Chinese expertise and innovations.

Europe's battery gigafactory ambitions have stumbled badly: The collapse of Sweden's Northvolt—once viewed as Europe's flagship gigafactory project—highlighted the risks of scaling production. The company, that was unable to reach nominal production because of quality issues, declared bankruptcy in November 2024 and then again in March 2025 with \$5.8 billion in debt, just \$30 million in cash and monthly losses of around \$100 million. The situation was worsened by the cancellation of the €2 billion offtake contract with BMW because of unacceptable delivery delays.³⁵ The Franco-French hopes fared little better: Stellantis-backed Automotive Cells Company (ACC) shelved its planned gigafactories in Italy and Germany in February 2026 and its French plant near Douvrin is experiencing ramp-up pushed difficulties that pushed it to seek help from the Chinese cell makers Eve Energy. Verkor's Dunkirk plant, meanwhile, remains well behind schedule.³⁶

By contrast, AESC, which is owned by China's Envision, is already producing at its Douai gigafactory. In April 2026, the facility reached its

first gigawatt-hour of battery cell output to supply Renault's R5. Four of its six production lines are now operational, with full 10 GWh annual capacity targeted by the end of 2027. AESC successfully deployed its advanced operational know-how on French soil, creating local jobs and transferring critical industrial skills to French workers.³⁷

To reach its equipment localization requests, Europe could look to structured partnerships that mirror the policies China itself utilized decades ago—conditioning strategic market access on European-majority (51%) joint ventures. This trend is emerging, as evidenced by the major clean tech framework proposed by think tanks like France's Institut Montaigne, or concrete market examples like the Vetrozelena wind project in southeastern Europe, which is a joint development between Europe's CWP and PowerChina Resources designed to blend local asset ownership with Chinese deployment speed.

Orano and China's XTC New Energy have also established Neomat CAM, a 49:51 joint venture to build a €1.5 billion cathode active material (CAM) plant in Dunkirk. The project reached final investment decision in March 2026 and is expected to deliver up to 80,000 tonnes of annual capacity and create approximately 1,300 direct jobs by the end of 2027.³⁸ Launched under the Sino-French Choose France framework, it is a JV-based localization model—rather than a Chinese-owned greenfield site—bringing to Europe a link in the gigafactories supply chain that the region currently lacks and complementing cell-assembly gigafactories like AESC's in Douai.

Over the longer term, true European independence cannot rely solely on foreign capital and technologies. The EU and member states must heavily ramp up public and private R&D funding, facilitate large-scale financing mechanisms for local clean tech, and aggressively streamline and reduce the bureaucratic regulations that currently stall factory construction and project deployment.

³⁴<https://presse.economie.gouv.fr/le-gouvernement-annonce-la-publication-du-cahier-des-charges-de-lappel-doffres-n10-dit-ao10-pour-lelien-en-mer/>

³⁵<https://techcrunch.com/2025/03/12/battery-manufacturer-northvolt-nears-the-end-as-it-files-for-bankruptcy-in-sweden/>

³⁶<https://www.euronews.com/business/2026/02/07/stellantis-backed-acc-shelves-plans-to-open-battery-gigafactories-in-italy-and-germany>

³⁷<https://www.usinenouvelle.com/auto/a-douai-lusine-de-batteries-daesc-envision-surfe-sur-le-succes-de-la-renault-r5-et-devient-la-premiere-veritable-gigafactory-francaise.2Q7G4UBKQNCY5DVNJRPHYCHOGVM.html>

³⁸<https://www.orano.group/en/news/news-group/2026/march/xtc-new-energy-and-orano-announce-the-construction-of-their-first-battery-cathode-active-material-manufacturing-plant-in-northern-france>





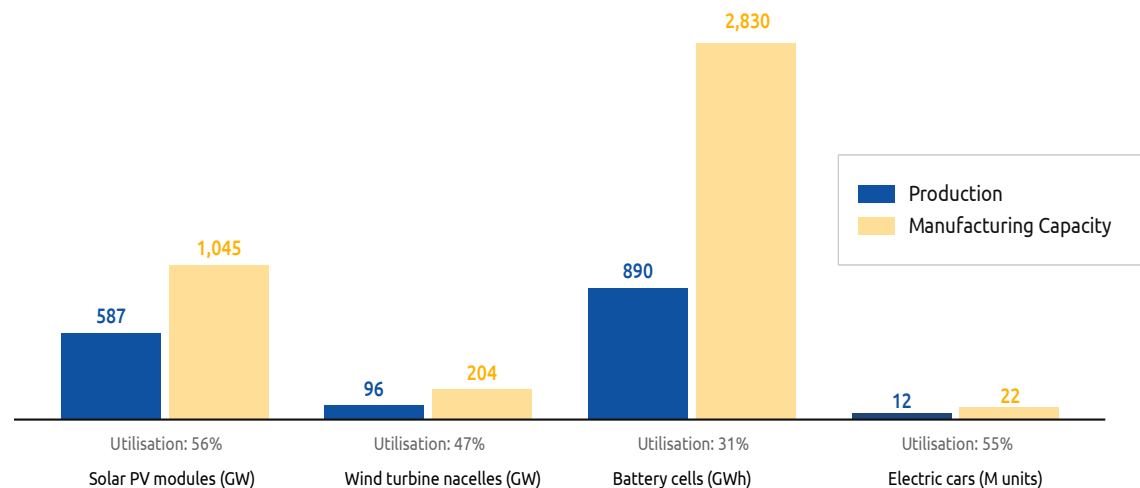
China's clean energy overcapacity: Why it can flood markets at unbeatable prices

China has built manufacturing capacity for clean energy hardware that exceeds demand—and the gap between capacity and production is widening.

In 2024, China's solar PV module manufacturing capacity stood at 1,045 GW against production of 587 GW (a 56% utilization rate); battery cell capacity reached 2,830 GWh against production of 890 GWh (31% utilization); wind turbine nacelle capacity was 204 GW against 96 GW produced; and electric car manufacturing capacity of 22 million units against 12 million sold. State-directed financing policy means that Chinese producers could operate at negative margins without facing the capital market discipline that would shut down a Western competitor. As a result, Chinese solar module export prices fell below \$0.10/W in 2025, which is below the cash cost of production for non-Chinese manufacturers. Chinese solar companies are almost all loss-making (net profit margins of -10% to -50% for major listed producers in 2025³⁹), yet they continue to expand capacity.

Figure 6

China manufacturing capacity vs actual production, 2024. Utilization rates of 31–78% reflect state-supported structural overcapacity enabling persistent below-cost export pricing.⁴⁰



Source: IEA 2025; J.P. Morgan Eye on the Market, 2026

⁴⁰IEA 2025; J.P. Morgan Eye on the Market, March 2026.

³⁹Eye on the market, Michael Cembalest, JP Morgan, March 3, 2026



Critical minerals and rare earths: The new resource chokepoint

The energy transition requires vast quantities of lithium, cobalt, nickel, copper, graphite, rare earth elements, and gallium. China controls not only a large share of global mining for several of these minerals (in China, Myanmar, Laos, and Africa) but, more importantly, also dominates the processing and refining stages that convert raw ore into battery-grade or magnet-grade material. This includes 97% of PV wafer production, 92% of permanent magnets (essential for wind turbines and EV motors), 95% of graphite processing, 98% of gallium production, and 87% of rare earth processing.

The 2025 Chinese rare earth export control episode—in which Beijing temporarily cut off rare earth exports to the U.S. in April 2025 before a partial easing in October—demonstrated precisely how this leverage can be activated.

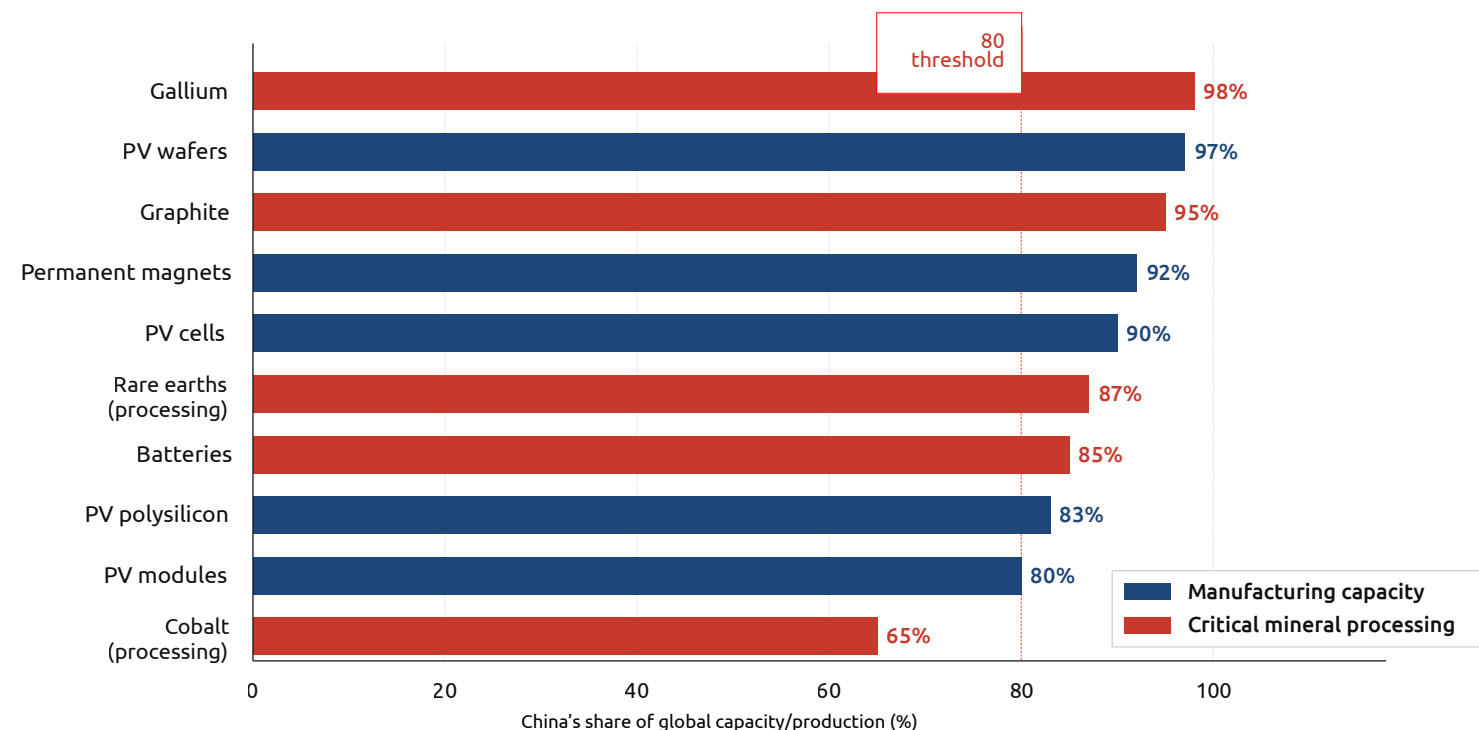
Diversification is underway: U.S., Canada, Australia, and the EU are all building strategic mineral reserves and developing local mining and refining capacity. However, the timelines are long—a new rare earth processing facility takes 7–10 years to secure permits, complete construction and get qualified. Shortening these timelines is becoming a strategic imperative.

Other ways to reduce dependence on Chinese rare metals and rare earths include developing recycling, as seen through the EU's new Batteries Regulation (EU) 2023/1542, which imposes minimum recycled content thresholds (mandatory from August 2031) for key metals. Another approach is to develop new technologies that avoid these minerals altogether, such as sodium-ion batteries, which use no lithium and rely on sodium, a far more abundant mineral.

Without localization of supply chains, recycling, developing rare metal-free new technologies, and building strategic reserves, the energy transition could become a new form of geopolitical dependency.

Figure 7

China's share of global clean energy manufacturing capacity and critical mineral processing. The 80% threshold (dashed line) is exceeded for virtually every key input to the energy transition.⁴¹



Source: IEA 2025; J.P. Morgan Eye on the Market, 2026

⁴¹IEA Global Critical Minerals Outlook 2025; J.P. Morgan Eye on the Market, March 2026.



Plant-level LCOE: An incomplete metric for intermittent generation costs

Levelized cost of energy has become the dominant metric for comparing electricity generation technologies. However, it is misleading when applied to intermittent sources. LCOE measures the average cost per MWh over a plant's lifetime, capturing capital, fuel, and operating costs. What it omits is what matters for grid reliability: the cost of making variable generation firm. This is the central economic question of the energy transition.

For a dispatchable generator—gas, nuclear, hydro—plant-level LCOE is a reasonable proxy for the system cost it imposes. For wind and solar, it is not because the full system cost includes five additional categories that LCOE ignores:

- **Profile and utilization costs:** Because solar and wind produce electricity in patterns that may not match demand, their effective utilization is lower than nameplate capacity suggests. A solar plant with a 25% capacity factor in Europe, which produces nothing at night and very little in winter, cannot be compared to a gas plant running at 80% based on LCOE alone.
- **Balancing and frequency services:** Synchronous generators (gas, nuclear, and hydro) provide inertia—physical resistance to sudden frequency changes—as a free by-product of generation. Wind and solar inverters provide none. As their share increases, grids must procure frequency regulation, fast-responding reserves, and synthetic inertia explicitly from other sources. These ancillary service costs are not reflected in any wind or solar LCOE estimate.
- **Grid and connection costs:** Renewable resources are often located far from demand centers (e.g., offshore wind or solar desert) and require long transmission lines. In France, the grid operator

RTE estimates that connecting the 18 GW of planned offshore wind will require €10–15 billion of dedicated transmission investment. In the U.S., ERCOT's Competitive Renewable Energy Zones program cost \$7 billion to connect west Texas wind to Houston. These costs are typically socialized across all ratepayers rather than attributed to the renewable capacity that triggered them.

- **Backup capacity costs:** Even with 80% renewable penetration, a grid must maintain near-100% backup capacity for periods of prolonged low generation. That backup, which is almost always gas, must earn sufficient revenue over limited running hours to remain economically viable. As renewable market share rises, gas plants run less but must still be available; their fixed costs are recovered through rising capacity payments or elevated spot prices during shortages.
- **Price cannibalization:** As solar capacity grows, it produces its maximum output during the same hours in every market (e.g., midday) driving wholesale prices towards zero or below during those hours. This means that each additional solar plant earns progressively less revenue per MWh, undermining the financial case for new investment and pushing the cost burden onto the residual system.

Excess renewables (and mainly solar) generation compared to demand leads to negative prices. France set a European record of a negative price of -€460/MWh on April 26, 2026, driven by low Easter demand and peak solar output exceeding 15 GW.

While both Europe and many U.S. states are experiencing a boom in solar capacity without a matching increase in storage capacity—leading to a surge in negative price hours during peak production—California has successfully begun decreasing the number of such hours (see figure 8). Between 2019 and 2025, the state aggressively increased the battery fleet from 500 MW to around 16 GW.

Here is a breakdown on how this battery fleet is operating:

- **The Battery Energy Storage System (BESS) “sponge” effect:** Instead of allowing mid-day solar gluts to overwhelm the grid, California's massive battery fleet acts as a strategic sponge. By charging (buying power) when solar output peaks, batteries create a demand floor that prevents prices from reaching negative territory.
- **Automated market integration:** California's charging infrastructure operates via automated real-time algorithms, which allows absorbing excess electricity faster and more efficiently than the battery frameworks currently found across Europe and other U.S. grids.

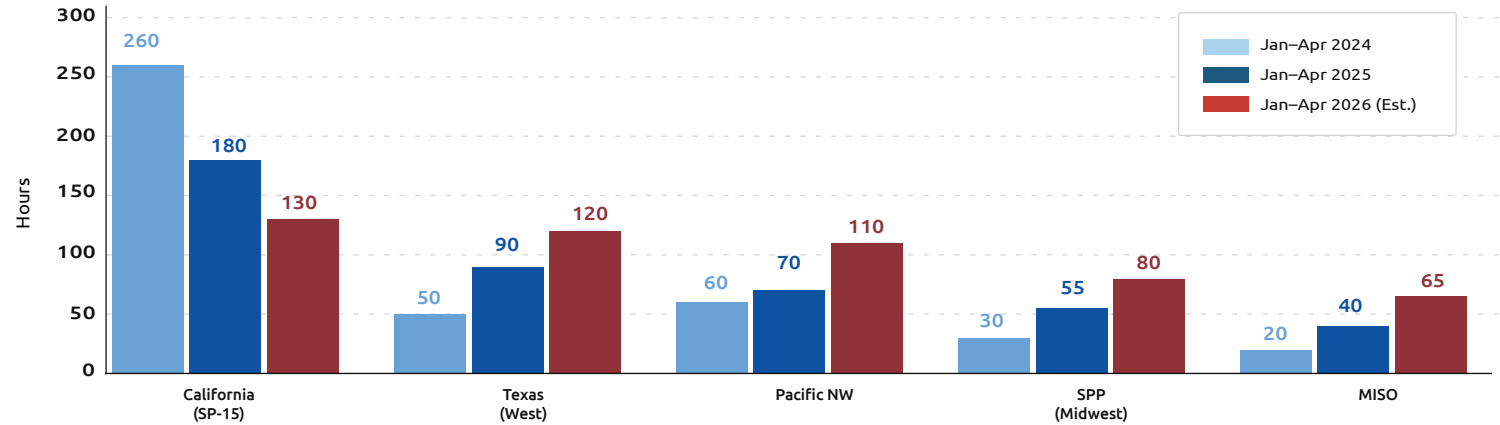




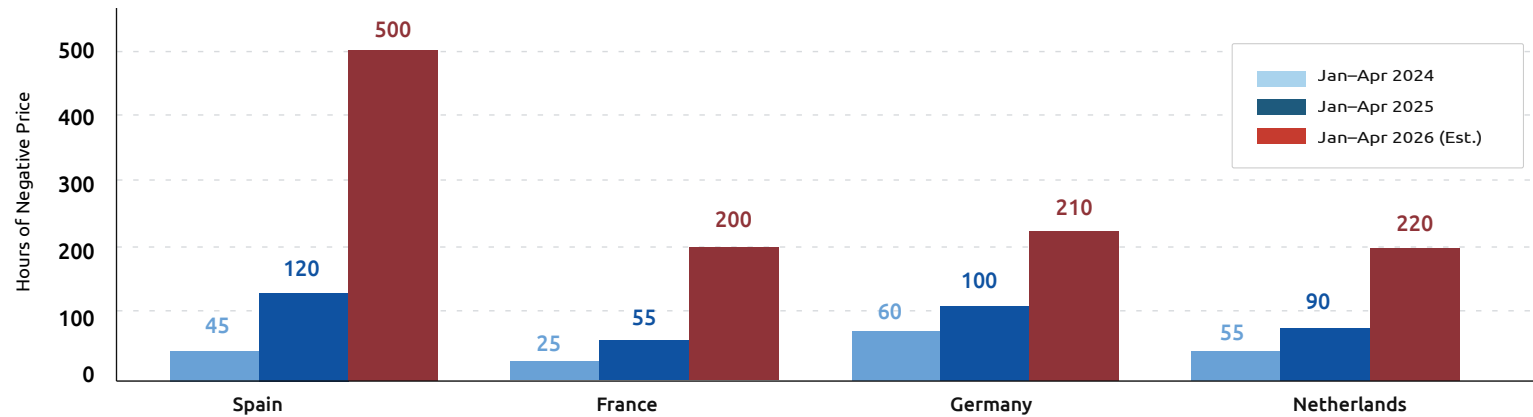
Figure 8

Hours of negative electricity prices in the US and Europe, Jan–Apr 2024–2026

US Hours of Negative Electricity Prices (Jan–Apr 2024–2026)



Accelerating Negative Price Hours in Europe (Jan–Apr)

Source⁴²: Ember; ACER; WEMO 2026 analysis.⁴²Ember; ACER.**Conclusion:**

LCOE comparisons between intermittent and dispatchable sources become increasingly misleading as renewable penetration rises. System wide levelized cost—which includes incorporating profile adequacy, balancing services, grid extra cost, inertia requirements, backup and cannibalization costs—is the only honest metric for policy comparison. The gap between the two is not a technical detail; it is part of the cost of the energy transition.





03

Clean and sovereign energies



The previous chapter concluded that hydropower, nuclear, and geothermal are the only non-fossil, emissions-free, and sovereign energy sources available.

However, hydropower is constrained by geography, requiring mountainous regions and suitable river systems for large-scale dam construction. While most developed countries have largely exhausted their viable sites, developing economies continue to build mega-scale hydroelectric projects. These include China's Three Gorges Dam (22.5 GW), Brazil's Belo Monte (11.2 GW), the Itaipu Dam on the Brazil-Paraguay border (14.0 GW) and Ethiopia's Grand Ethiopian Renaissance Dam (5.15 GW). At peak output, the Three Gorges Dam alone can generate electricity equivalent to roughly 15–20% of France's annual electricity consumption. This analysis will bypass further examination of hydropower to focus exclusively on nuclear and geothermal energies.



⁴³<https://www.edf.fr/groupe-edf/espaces-dedies/journalistes/tous-les-communiques-de-presse/le-groupe-edf-partage-les-principaux-enseignements-de-son-rapport-sur-la-modulation-de-son-parc-de-production>

3.1 Nuclear: Global existing fleet

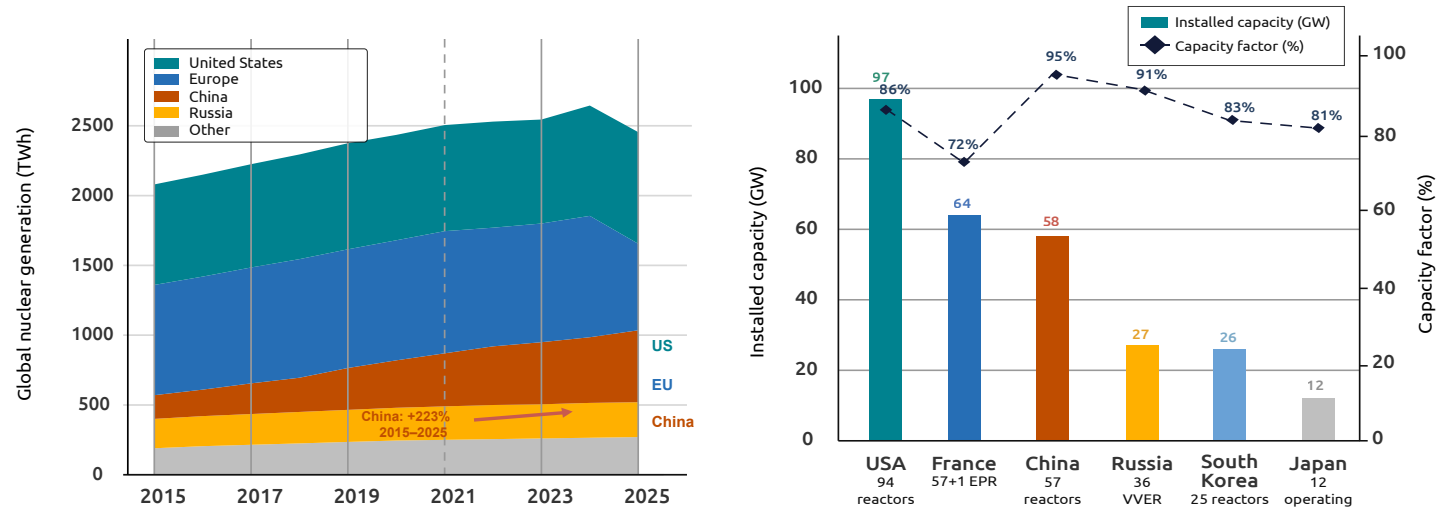
Nuclear power delivered 2,677 TWh globally in 2024—a record surpassing the previous peak set before the 2011 Fukushima accident. As of May 2026, 416 reactors operate in 31 countries (376 GW net capacity) and 74 reactors totaling 66 GW are under construction. The global average capacity factor stands at 83%, the highest ever recorded.

The French reactor's lower capacity factor (see Figure 9) is linked to the high share of nuclear electricity in France. Because of current rules, when there is excess generation, nuclear power plants will almost always reduce their output before non-dispatchable renewables (solar and wind) are curtailed by the grid operator. French nuclear reactors can safely perform load following and modulate their output by up to 80% of their nominal capacity in under 30 minutes. However, cycling a reactor's output up and down to match renewable volatility introduces significant technical challenges and it can accelerate the aging of components and potentially decrease the overall lifetime of the plant.⁴³

China is now the fastest-growing nuclear nation, with a 223% generation increase between 2015 and 2025.

Figure 9

Global nuclear generation by region 2015–2025 (record 2,677 TWh in 2024) and installed capacity/capacity factor by country (May 2026)⁴⁴



⁴⁴IAEA PRIS May 2026; World Nuclear Performance Report 2025; IEA; WNA 2026.



Existing fleet LCOE stands at \$35–80/MWh, making it the cheapest firm, clean, 24/7 power source. Where safety cases are supported, lifetime extension to 60–80 years is the quickest and cheapest route to sustained nuclear electricity, in that capital is fully depreciated, fuel costs are low, and the operational workforce is trained. The U.S. Nuclear Regulatory Commission is processing applications for 80-year operating licences for 20 reactors. France’s €51 billion Grand Carénage program (2014–2035) will extend all 57 pressurized water reactors (PWRs) to at least 50 years, with a further 60-year assessment in progress.

Case Study | Belgium: Nationalizing nuclear as a sovereign asset

In April 2026, the Belgian government announced the full nationalization of the Doel and Tihange nuclear power stations, acquiring Engie-Electrabel’s remaining 50%+ stakes for an estimated €4 billion. The move is explicitly framed as an energy sovereignty decision. Belgium generates ~50% of its electricity from nuclear power, and the government concluded that this strategic national asset cannot remain under majority private foreign ownership. Belgium joins France (EDF is fully state-owned), Finland (Fortum is state majority) and Sweden (Vattenfall is fully state-owned) in treating nuclear generation as a national sovereign asset.

The table below shows as of May 2026 the five major nuclear fleet countries and Germany that had an important fleet:

Table 3 — Global nuclear fleet as of May 2026⁴⁵

Country / Region	Reactors	Capacity	2025 Output	Key notes
United States	94	97 GW	~800 TWh	~19% of U.S. electricity; 20 reactors seeking 80-year extensions.
France	57 PWR + 1 EPR	63 GW	~400 TWh	67% of French electricity; highest share globally.
China	57 (+37 building)	55–61 GW	488 TWh (record)	~5% of electricity; Chinese nuclear installed capacity will surpass U.S. by 2030.
South Korea	26 (+2 building)	26 GW	~190 TWh	~30% of electricity; APR1400 is a leading export technology.
Russia	36 VVER	27 GW	~225 TWh	~20% of electricity; Rosatom leads global nuclear exports.
Germany	0	0	0	Nuclear total exit April 2023; negative prices surging as a direct consequence.

3.2 Nuclear renaissance: The new large reactor pipeline

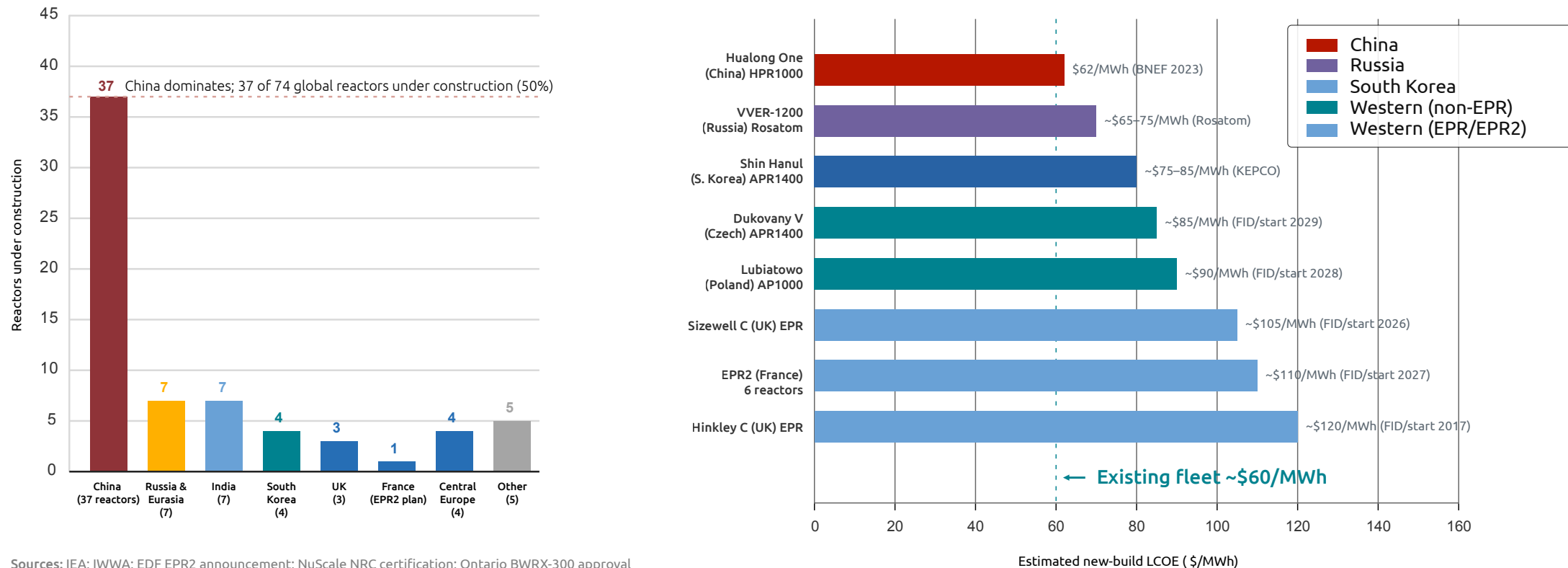
After two decades of stagnation in Western markets, a genuine nuclear renaissance is underway. The term “renaissance” was used prematurely in the 2000s, but this time the evidence is structural: 74 reactors are under construction globally as of May 2026, representing the largest pipeline since the 1980s; governments are committing to new nuclear plants in France, Poland, Czech Republic, Hungary, and the U.K.; and data center operators are signing nuclear power purchase agreements worth tens of billions of dollars. The Hormuz crisis has acted as a catalyst, in that governments that had hesitated on nuclear permitting are now accelerating their delivery. China dominates with 37 of 74 reactors under construction, roughly 50% of the global pipeline. Its Hualong One (HPR1000) has achieved an estimated LCOE of \$62/MWh. Russia’s VVERs are competitive at \$65–75/MWh through serial construction, proving that large nuclear can compete with gas on cost when

⁴⁵IAEA PRIS; World Nuclear Association.



Figure 10

Reactors under construction by region (May 2026, 74 total) and new-build LCOE comparison. China and South Korea prove serial construction delivers competitive costs; Western programs are rebuilding supply chains.⁴⁶



Sources: IEA; IWWA; EDF EPR2 announcement; NuScale NRC certification; Ontario BWRX-300 approval

built in series. South Korea's APR1400, deployed in the UAE and Czech Republic, is the leading Western-compatible design, with KEPCO quoting \$75–85/MWh for the Dukovany V project. Western Europe is at an earlier stage of supply chain reconstruction: France's EPR2 program (6 reactors, FID 2027, ~\$110/MWh estimated) and the U.K.'s Sizewell C (FID 2026, ~\$105/MWh) carry higher costs but are critical for renewing each country's respective nuclear fleets. The key lesson from the cost comparison: nuclear LCOE falls sharply with serial construction (as seen in France in the 1980s). No Western country has yet committed to the serial program required to achieve Asian and Russian cost levels, but the policy direction is now clearly set.

⁴⁶IEA; WNA; EDF EPR2 announcement; NuScale NRC certification; Ontario BWRX-300 approval, May 2026.



The structural drivers for nuclear expansion or development, including energy sovereignty, data center demand for 24/7 clean power, and the Hormuz security shock, are more durable than any previous wave. For the first time since 1979, the question is not whether new nuclear will be built in Europe and elsewhere, but how fast. However, many hurdles must be overcome: financing the very large capital expenditures, local public oppositions, project management, construction length, supply chain readiness, and qualified workforce availability.

3.3 Small modular reactors (SMRs): Global status

SMRs (generally defined as reactors below 300 MWe) promise factory fabrication, shorter build times, and lower upfront capital. Figure 11 shows the global reactor landscape as of May 2026 across six technology families: pressurized water reactors (PWRs); boiling water reactors (BWRs); high-temperature gas-cooled reactors (HTGRs), sodium-cooled fast reactors (SFRs), molten salt reactors (MSRs) and lead-cooled fast reactors (LFRs). Each differs in its choice of moderator, coolant, fuel, fuel cycle, risk profile and regulatory pathway.

SMALL MODULAR REACTORS — GLOBAL STATUS (MAY 2026)

Only Russia and China have delivered. Canada BWRX-300 (Ontario, 2030) is the Western bellwether. LCOE projections are aspirational.

Figure 11
Small modular reactors: global status (May 2026). Only Russia and China have delivered operational units. Canada’s BWRX-300 (Ontario, 2030) is the Western bellwether.⁴⁷

Country / Project	Status	Key facts
Russia Akademik Lomonosov FNPP 2 × KLT-40S, 35 MWe each	OPERATIONAL since 2019	World’s first floating SMR, moored at Pevek (Arctic). 2nd FNPP (Yakutia) under construction. Land RITM-200N programme (Yakutsk, 6×55 MWe) targeted 2027. Most mature SMR programme globally.
China HTR-PM (Shidaowan) 2×100 MWt → 210 MWe	COMMERCIAL Dec 2023	World’s first commercial HTGR. TRISO pebble fuel — China plans 18 additional HTR-PM modules at Shidaowan. Commercially proven; replication slow.
China CFR-600 (sodium fast reactor) 300 MWe	NEAR OPER. grid ~2026	Sodium-cooled fast reactor; bridge to China’s closed fuel cycle. Will be the world’s largest operational fast reactor if successful. Grid connection expected 2026.
United States NuScale VOYGR 77 MWe / module (PWR)	NRC CERTIF. NO ORDER	First Western NRC Design Certification (May 2025). Idaho Carbon Free Power Project cancelled Nov 2023 at \$89–130/MWh. Gap between regulatory approval and commercial viability.
United States TerraPower Natrium 345 MWe SFR, Wyoming	CONSTR. started 2024	First privately financed advanced reactor in US (DOE ARDP). Sodium SFR + molten salt thermal buffer. Target 2030. Risk: HALEU fuel (20% enriched) not in commercial supply.
Canada BWRX-300 (Darlington, ON) 300 MWe BWR — GEH design	APPROVED May 2025	The western bellwether. Ontario approved May 2025. Target: 1st unit 2030; 4 units by mid-2030s. If delivered on time and budget, it transforms the Western SMR outlook.
United Kingdom Rolls-Royce SMR 470 MWe PWR (factory-built)	GDA Phase pre-licensing	UK national SMR champion. £210m government support. GDA with ONR underway. UK target: 24 GWe nuclear by 2050 (SMRs central). Operational target: early 2030s.
France Calogena CAL30 + Newcleo 300 MWt heat / 74 MWe LFR	DEVT pre-licensing	Calogena: heat-only PWR for urban heating and industry. Newcleo: 74 MWe lead-cooled FBR using MOX. Both are 2035+ propositions.

Key Conclusions	
1) Six technology families PWR, BWR, HTGR, SFR, MSR and LFR. Each has different fuel, coolant, risk profile and regulatory pathway.	2) Only Russia & China delivered Western SMRs are 5–10 years behind. Russia’s advantage: serial production, vertical fuel cycle, state financing.
3) BWRX-300 is the bellwether. If Ontario delivers on time & budget (2030), it transforms the entire Western SMR outlook.	4) LCOE does not apply yet. Vendor projections are aspirational. Credible LCOE requires a serial programme — no Western country has committed to one yet.

Sources: IAEA PRIS (May 2026); Rosatom; CNNC; CIAE; NuScale/NRC; TerraPower/DOE; OPG/GEH; Rolls-Royce SMR/ONR; Calogena; Newcleo; World Nuclear Association 2026; WNA Performance Report 2025.

⁴⁷IAEA; WNA; NRC; GEH; KEPCO; Rolls-Royce SMR; EDF; BWXT (May 2026).





Four key conclusions emerge:

- First, only Russia and China have delivered operational SMRs. Western programs are years behind. Russia's advantage is state financing and serial production; in China it is the state-directed industrial system that built HTR-PM from concept to commercial operation in 15 years.
- Second, Canada's BWRX-300 (Ontario Power Generation, approved May 2025, target 2030) is the decisive Western test case. If it is delivered on time and within budget, it would give a serious example for Western SMR development.
- Third, the NuScale VOYGR, the first Western SMR to receive an NRC Design Certification (May 2025), is a warning. The project was cancelled at \$89–130/MWh, revealing the gap between regulatory approval and commercial viability.
- Fourth, LCOE projections for unbuilt Western SMRs are aspirational, as credible cost estimates require a serial construction program that no Western country has yet committed to.

Bottom line on SMRs: The technology works (Russia and China prove it). The commercial challenge in the West is building and financing the first-of-its-kind unit at an acceptable cost—and then committing to the serial program that makes the economics of building dedicated equipment parts and nuclear fuel manufacturing plants work. Over time, the market is likely to consolidate around just two or three reactor technology families, which may differ from the light water reactor (PWR and BWR) technologies that dominates today's large-scale nuclear fleet.

3.4 Nuclear fusion: The longtime horizon

Fusion—the energy source of stars, which fuses hydrogen isotopes rather than splitting heavy atoms—remains the most consequential long-term bet in energy. It produces no CO₂, no long-lived radioactive waste, and is fuelled by deuterium, which is extractable from seawater in unlimited quantities. This very promising technology is still far from proven results and the commercialization timeline remains highly uncertain.

Recent milestones should be mentioned.

In December 2022 the U.S. National Ignition Facility achieved the first fusion ignition by inertial confinement, generating 3.15 megajoules (MJ) from a 2.05 MJ laser input. While this represents a scientific milestone, it did not deliver a net positive energy, as it required 300 MJ of grid electricity to drive the lasers.

In January 2025, China's Experimental Advanced Superconducting Tokamak (EAST) maintained high-confinement plasma for 1,066 seconds, a record subsequently broken by the French-hosted WEST tokamak at 1,337 seconds in February 2026. These milestones demonstrate plasma stability, a necessary—but not sufficient—condition for commercial fusion.

Private capital has arrived in force: 53 companies have raised a cumulative \$9.7 billion (2025) across radically different approaches: tokamaks with high-temperature superconducting magnets (Commonwealth Fusion Systems' SPARC, targeting first plasma 2027); inertial confinement (National Ignition Facility (NIF) approach); magneto-inertial confinement (Helion, backed by Microsoft); and Z-pinch designs. Commonwealth Fusion's SPARC device, currently under construction in Massachusetts, is the most technically advanced Western privately funded project. The International Thermonuclear Experimental Reactor (ITER) tokamak in France, now targeting first plasma in 2034, remains the world's largest publicly funded fusion experiment and the most rigorous test bed for materials and plasma physics at scale.



Fusion is a genuine long-term electricity generation option, but “commercially viable fusion” before 2040 or even 2050 is extremely unlikely according to a majority of plasma physicists. However, investing in R&D should continue as electricity generated by fusion is a potential transformational option for mid-century and beyond.

Conclusion:

In developed countries, SMRs are not an alternative to building large reactors. It is likely that we will see the coexistence of both reactor types. To safely construct and operate SMRs, developing countries must acquire the necessary technical and regulatory expertise, as well as the means to control nuclear materials. Nuclear fusion is a genuine but very long-term option.

3.5 Geothermal energy

Geothermal is the only renewable source capable of generating electricity and heat continuously, with capacity factors of 88%, compared to ~25% for solar and ~35% for onshore wind.⁴⁸ Geothermal output does not vary with weather, time of day, or season. However, at present, this energy source is available only in certain geological areas.

Global geothermal power capacity stands at 17,173 MW in 2025; direct heat use reached 245 TWh in 2024, a 20% increase.⁴⁹ Crucially, ~80% of geothermal energy is consumed as heat rather than being converted to electricity. This supports use cases like district heating,

greenhouse growing, aquaculture, and food processing. China, the U.S, and Turkey represent approximately 65% of global geothermal energy production.

Conventional geothermal vs enhanced geothermal systems (EGS)

Conventional geothermal requires tectonic hotspots—natural reservoirs of hot water or steam accessible within 0.5 to 3 km depth. This limits deployment to Iceland, Indonesia, Kenya, Nevada, New Zealand, France, and a handful of other geological settings. This geographic constraint explains why conventional geothermal has barely grown over two decades despite its favorable baseload profile. Geothermal power plants capture and process the heat differently depending on the temperature of the geothermal fluid (hot water or steam).

Conventional hydrothermal flash technology is used for high temperature reservoirs while hydrothermal binary cycle plants are a more modern technology designed for lower-temperature reservoirs.

EGS technology extends the geothermal potential. By injecting fluid into hot dry rock, fracturing it to create heat-exchange pathways, and recovering thermal energy anywhere on Earth at sufficient depth, it dramatically increases potential geothermal production sites. EGS received the majority of the \$800 million invested in novel geothermal globally in 2024–2025.⁵⁰

The cost gap: Geothermal vs wind and solar

The plant-level LCOE of conventional geothermal power is approximately \$70/MWh for flash plants and \$103/MWh for binary plants, compared with around \$58/MWh for utility-scale solar and \$62/MWh for onshore wind. On a plant-level LCOE basis, conventional geothermal is therefore somewhat more expensive. But this comparison is misleading: geothermal has an 88% capacity factor, versus ~25% for

solar, allowing it to provide firm, dispatchable power without the same backup capacity requirements. When adjusted for the full system value of geothermal versus intermittent renewables, geothermal economic position improves significantly—though a cost gap persists. For example, 2025 geothermal PPAs signed by Ormat for commercial projects reached \$100–110/MWh, compared to wind at \$75/MWh and solar at \$60/MWh.⁵¹ For EGS, deep binary costs remain high (\$200–380/MWh on National Renewable Energy Laboratory (NREL) central estimates), though costs are declining rapidly with drilling learning curves. The chart below illustrates the full cost range across technology types and provides direct comparison with wind and solar.



⁴⁸U.S. EIA, Electric Power Annual 2025 — average capacity factors by generating technology.

⁴⁹IEA Future of Geothermal Energy (2023); ThinkGeoEnergy (January 2026).

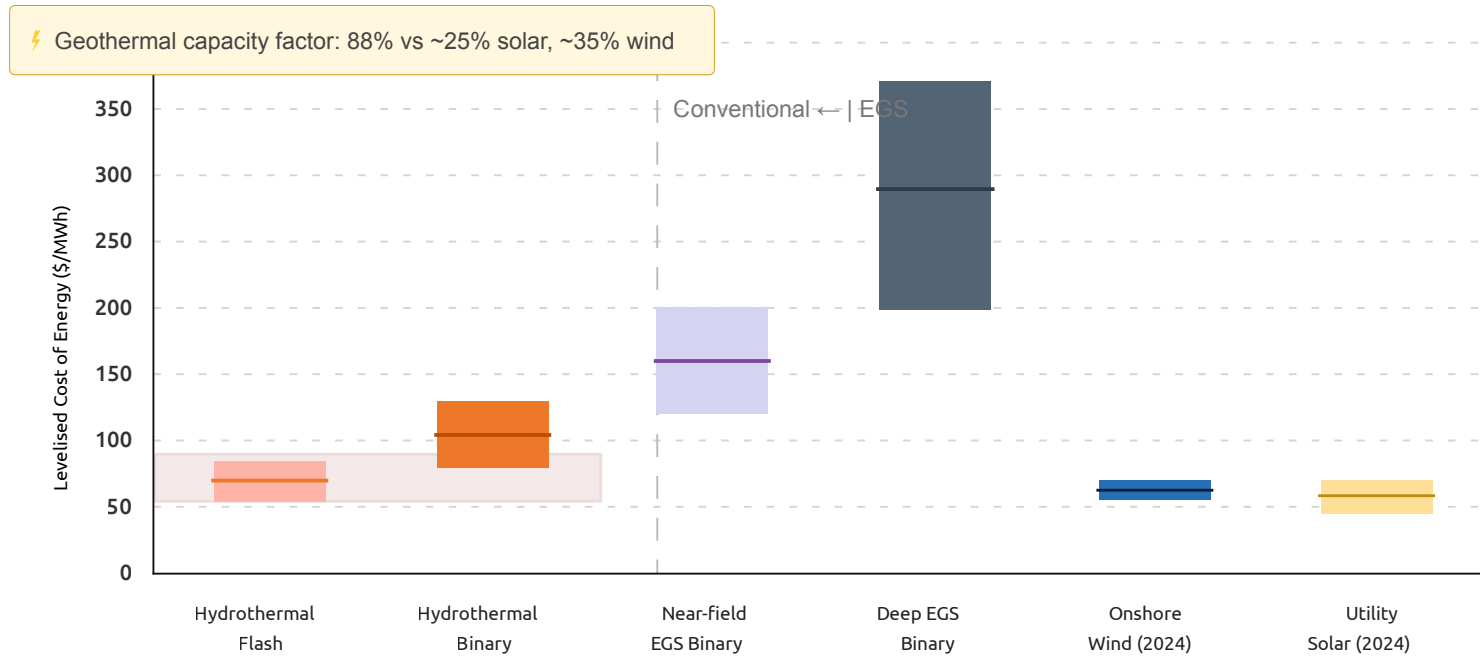
⁵⁰Sightline Climate, Climate Tech Investment Trends 2025: geothermal funding reached \$558m in 2024 alone, with cumulative 2024–2025 funding approaching \$800m, concentrated in EGS developers.

⁵¹LevelTen Energy, PPA Price Index, Q4 2025 (geothermal, wind and solar benchmark contract prices); Ormat Technologies, Form 10-K (FY2025).



Figure 12

LCOE ranges for geothermal technologies vs wind and solar, 2024. Geothermal's 88% capacity factor (vs ~25% solar) significantly changes the system value comparison beyond plant-level cost.⁵²



Source: NREL / National Laboratory of the Rockies, Jan 2026; Ormat; LBNL 2023; J.P. Morgan, 2026

Pathways and limitations

Several constraints limit near-term geothermal scaling. Permitting takes 7–10 years, drilling costs rise non-linearly with depth, and drilling may pose seismic risks that local communities fear. These factors, along with high upfront capital cost, makes geothermal electricity significantly riskier than solar or wind electricity generation.

⁵²NREL / National Laboratory of the Rockies, Jan 2026; Ormat; J.P. Morgan, 2026.

⁵³NREL life-cycle GHG emissions data for geothermal power plants; IPCC AR6 Working Group III, Annex III (lifecycle emissions factors).

⁵⁴U.S. Department of Energy / Lawrence Berkeley National Laboratory, Salton Sea Lithium Resource Assessment (December 2023).

Conventional geothermal plants emit approximately 45 g CO₂/kWh from naturally occurring CO₂ trapped in rock formations. This is comparable to solar on a lifecycle basis and 10–20 times lower than gas.⁵³

The most robust near-term applications—ground-sourced heat pumps for buildings and low-temperature industrial heat—carry far lower cost and technology risk than utility-scale geothermal electricity plants.

Lastly, in certain locations, geothermal brines contain lithium. This is the case in geothermal reservoirs in Eastern France, as well as in the U.S. The U.S. Department of Energy (DOE) estimates that geothermal brines beneath California's Salton Sea—known as "Lithium Valley"—contain enough lithium to produce up to 375 million EV battery packs. The resource could be extracted using Direct Lithium Extraction (DLE) alongside geothermal power generation⁵⁴

Conclusion:

Geothermal is an under-deployed clean energy resource precisely because it requires up-front geological risk-taking that markets under-reward. Its 88% capacity factor makes it a complement to wind and solar in a high-renewable grid, providing a firm base-load. EGS is the technology to watch over the next 3–5 years. If drilling costs decline quickly, it could extend geothermal production areas and make it competitive with gas peakers by 2030 (in geologically favorable locations). That outcome is not guaranteed, but it is no longer implausible.



04

Electrification as a shield to fossil dependency





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When the TTF gas spot benchmark spiked, day-ahead electricity prices in gas-reliant nations like Italy and Germany soar, reaching €120–150/MWh. In contrast, countries with diverse energy mixes such as France and Spain experienced much more limited impacts, maintaining prices closer to €60–80/MWh.

IEEFA, April 2026

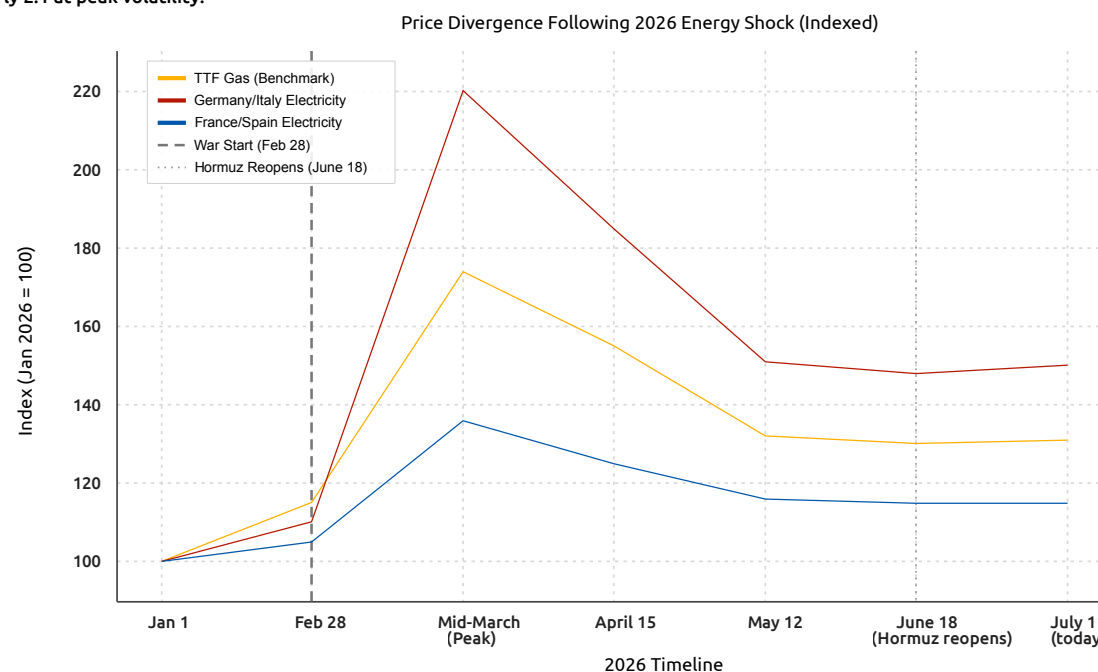
The Iran conflict has illustrated a fundamental principle: the more an economy is electrified—and the more that electricity comes from non-fossil sources—the less vulnerable it is to fossil fuel shocks. Replacing gas boilers with heat pumps, petrol cars with EVs, and oil-fired industrial processes with non-fossil electricity will progressively shield the economy from oil and gas supply crises.

4.1 EU electricity price divergence: The clean mix advantage

The Hormuz crisis provided a live stress test of European electricity markets. Figure 13 captures this divergence in real time, indexed from January 2026.

Figure 8

EU electricity price divergence following the 2026 energy shock (indexed, Jan 2026 = 100), through July 11, 2026. France and Spain outperform Germany and Italy by a factor of nearly 2:1 at peak volatility.⁵⁵



At the peak of market volatility in mid-March 2026, wholesale electricity prices in Germany and Italy—both heavily reliant on fossil fuel generation—rose to an indexed level of around 220, more than double their January baseline, closely tracking the TTF natural gas benchmark. By contrast, France, with its predominantly nuclear power system (around 70%), and Spain, with a high share of renewables, peaked at around 135—less than 35% above their pre-war baseline

⁵⁵Ember European Electricity Review 2026; IEEFA Europe Electricity Prices April 2026; IEA Electricity 2026; Eurostat; ENT-SO-E. Norway/France prices estimated from grid operator data.





4.2 Government policies: The comparative picture

Because of the Hormuz crisis, many governments, with the exception of the U.S., decided to increase the electrification share of their economies. The table below summarizes some of these plans.

Table 4 — Comparative electrification policy landscape⁶²

Dimension	EU / France	United States	India	China
Policy ambition	Very high — binding legislation Energy Performance of Buildings Directive (EPBD), Internal Combustion Engine (ICE) ban 2035)	Reversed — Inflation Reduction Act (IRA) partially repealed July 2025	High — NEP 2026 ⁵⁶ , SHANTI Act ⁵⁷	NDRC ⁵⁸ Highest — mandates + subsidies + manufacturing overcapacities
Buildings (heating)	Fossil boiler ban (FR 2026, EU 2040); heat pump grants	IRA heat pump credits partially maintained	Limited — mainly urban	District heating electrification
Transport (EVs)	EU ICE ban by 2035 (likely to be postponed or amended) ⁵⁹ ; French EV leasing; subsidies	EV credits partially repealed; state action continues	PM E-DRIVE ⁶⁰ ; 8% EV share 2025	16.5 million New Energy Vehicles ⁶¹ sold in 2025; fleet mandates
Clean power base	Nuclear (nuclear renaissance in Europe); wind plus solar are growing	Gas ~40% of electricity	50% non-fossil capacity reached 2025	Wind and solar ~22%; coal still at 55%

- **Legacy contract trap:** Spain, Italy, and Germany carry multi-billion-euro obligations to pre-2014 renewables at €150–200/MWh. France’s annual Contribution au Service Public d’Electricité (CSPE) levy of €3.5 billion is largely committed to legacy solar contracts.
- **Workforce and execution gaps:** 750,000 additional heat pump installers needed in Europe by 2030.
- **Policy incoherence and reversibility:** Germany’s Buildings Energy Act (GEG) reversal (2024)⁶³ and U.S. IRA rollback (July 2025) demonstrate electoral fragility. Sweden’s carbon tax (€134/tonne since 1991) is the counter-model.⁶⁴

One durable solution: Carbon pricing, a mechanism that is resilient to gas price swings, budget cycles, and electoral change. ETS2—the extension of the EU Energy Trading System (ETS) in 2027 for heating fuels—is a lever for the next phase but will increase costs for European citizens.

However, as seen in the past, these plans could be delayed or partially reversed. Here are a few risks that need to be overcome:

- If fossil fuel prices go down after the Hormuz crisis, heat pump ROI is decreasing (e.g., Germany’s heat pump market fell 48% in 2024 when gas prices declined).
- **Budget reallocation:** ReArm Europe allocated €800 billion to defense over four years, which could cannibalize EU energy transformation funds. France’s debt at 113% GDP creates a fiscal pressure and could reduce energy transition spending.

⁵⁶Draft National Electricity Policy (NEP) 2026 – PIB <https://www.pib.gov.in/PressReleasePage.aspx?PRID=2216661®=3&lang=2>
⁵⁷Sustainable Harnessing and Advancement of Nuclear Energy for Transforming India Act, <https://idsa.in/publisher/issue-brief/shanti-act-and-indias-nuclear-energy-governance-framework>
⁵⁸National Development and Reform Commission <https://www.sciencedirect.com/science/article/pii/S2949720524000298>

⁵⁹<https://www.cleanenergywire.org/news/commissioner-says-eu-amend-2035-ban-new-combustion-engine-cars>
⁶⁰PM Electric Drive Revolution in Innovative Vehicle <https://pmedrive.heavyindustries.gov.in/>
⁶¹New Energy Vehicle <https://dieselnet.com/standards/cn/nev.php>
⁶²WEMO 2026 analysis based on national policy announcements (European Commission, US Congress, India NEP 2026, China NDRC/NEA).

⁶³Germany’s Buildings Energy Act (GEG) originally mandated that nearly all newly installed heating systems must run on at least 65% renewable energy starting in 2024, but it was heavily diluted after intense political debate Rilling, B. (2024). Renewable gases fueling the energy transition in residential heating and private transportation: A multi-level perspective. Heidelberg University. https://archiv.ub.uni-heidelberg.de/volltextserver/35842/1/Dissertation_Rilling_final.pdf
⁶⁴Sweden ETS data — Swedish Energy Agency.

4.3 Electric vehicles: From niche to mass market

Electric car sales are projected to top 23 million units worldwide in 2026, rising approximately 11% year-on-year—meaning roughly one in every four new cars sold globally is now electric. China continues to dominate the market, accounting for over 55% of global volume, followed by Europe at 20–22%, whereas the U.S. market share lags due to regulatory shifts.

Beyond regulation (see Table 4), several factors continue to support EV growth, though setbacks remain possible.

The 2026 ‘Hormuz effect’ on EV sales

The 2026 closure of the Strait of Hormuz led to gasoline price surges and reversed the plateau in European EV adoption. EU EV registrations increased more than 23% year-on-year, as consumers rushed to insulate themselves from volatile and rising gasoline prices.⁶⁵ This crisis showed that vehicle electrification meets not only a climate change mitigation objective, but also a national energy sovereignty objective, provided cars are manufactured locally and electricity is CO2 emissions free.⁶⁶



⁶⁵International Energy Agency (IEA) Global EV Outlook & Market Tracker (2026 mid-year update).

⁶⁶Firstpost Vantage Geopolitical Infrastructure Report, ‘How the Strait of Hormuz Crisis Reshaped Global Fleet Transport & Fuel Premiums’ (2026).

Battery pack prices fell from ~\$700/kWh (2015) to \$115/kWh (2024) and ~\$95/kWh (2025)—an 84% decline. Total cost of ownership is approaching parity with ICE cars, even without subsidies in many market segments.

Battery technology is also evolving as shown below:

Table 5 — Battery technology evolution: chemistry comparison (May 2026)⁶⁷

Chemistry	Status	Key characteristics and trajectory
LFP (Lithium Iron Phosphate)	Dominant and growing	No cobalt or nickel. Lower cost, better supply resilience. Two-thirds of Chinese EVs in 2024. China controls 92% of LFP cathode mineral processing.
NMC (Nickel Manganese Cobalt)	Premium segment, declining share	Higher energy density for long-range vehicles. More expensive. ESG concerns on cobalt mines exploitation in Congo driving shift to lower-cobalt NMC market share.
Sodium-ion	Commercial in China 2024	No lithium uses abundant sodium. CATL first commercial deliveries in 2024, Envision AESC delivery in 2026. Lower energy density adequate for urban EVs
Solid-state	Targeting 2027–2028	Potentially doubles energy density, eliminates fire risk, enables faster charging. Analysts project 2028–2030 for meaningful commercial production.
Silicon anode (Li-ion)	Technology Readiness Level (TRL): 7 early commercialization	~10× more lithium storage than graphite anode—higher density, faster charging. Near-term (2025–27) improvement.

⁶⁷IEA Global EV Outlook 2025; ACEA; Bloomberg NEF Battery Price Survey 2024–2025.

Why EV sales growth could be slower than forecasted

Five structural headwinds could cause EV adoption to fall significantly below the most optimistic projections:

- **Price gap persists:** The average EV car in Germany costs 20% more than an equivalent internal combustion car; in the US it is 30% more.
- **U.S. policy reversal:** The One Big Beautiful Bill Act (July 4, 2025) significantly limits IRA EV incentives. Federal targets have been abandoned; the U.S. market now depends on state-level policies that vary widely and are less durable.
- **EU–China trade tensions:** 35.3% tariffs on Chinese EVs (October 2024) increases the cost of Chinese EVs.
- **Low oil prices:** Post-Iran war Brent settling near \$70/barrel makes the EV total cost of ownership case less compelling than at \$100/barrel.
- **Charging infrastructure:** Only around 7 million public charging points exist globally.⁶⁸ A 6.5X increase to ~45 million is needed by 2030. This physical infrastructure build could take years and requires financing and grid connection capacity that is already queued.
- **Fiscal revenue losses:** Governments are losing fuel taxes and could be tempted to reduce the operating cost advantage of EVs.

⁶⁸IEA, Global EV Outlook 2026 — Electric vehicle charging; IEA: 1.8 million public EV charge points added globally in 2025, China accounts for 65% — EV Infrastructure News <https://www.evinfrastructurereports.com/ev-networks/iea-1-8-million-public-ev-chargepoints-added-globally-in-2025-china-accounts-for-65>



The net outlook:

EV growth will continue, but the decade-end trajectory is likely to be 40 million annual sales globally by 2030 rather than the 50+ million that the most bullish scenarios assumed in 2022–2023. However, the direction is clear: EV growth will continue though the growth rate may fluctuate.

Vehicle-to-grid (V2G): An uneven deployment

The grid could benefit from storage capabilities provided by 40 million EVs equipped with V2G technology. This fleet could provide 200 GW of grid flexibility. However, V2G deployment is low and uneven.

V2G is operational mainly in fast, second-by-second balancing markets: PJM in the U.S. pioneered EV frequency regulation via the University of Delaware/NRG project in 2013, with demonstration fleets since introduced in Denmark, the U.K., Japan, and China.⁶⁹

Grids without that structural need—France’s nuclear-and-hydro-heavy system, for instance—simply have weaker demand, which partly explains uneven adoption.⁷⁰

The bigger brake is consumer reluctance. Owners worry about not having full charge when needed, a top barrier in EV-owner surveys.⁷¹

Adoption is also limited by thin market infrastructure, as dedicated aggregators to pool vehicles into tradeable grid resources, and bidirectional standards like ISO 15118-20, remain immature. In addition, battery degradation concerns outpace current warranty and insurance treatment.⁷²

⁶⁹<https://news.delaware.gov/2013/04/26/in-first-electric-vehicle-to-grid-technology-sells-power-to-pjm-power-grid/>

⁷⁰<https://www.sciencedirect.com/science/article/pii/S0957178726000342>

⁷¹A systematic review of citizen perceptions and expectations of V2G adoption — Discover Sustainability

⁷²<https://www.patsnap.com/resources/blog/articles/vehicle-to-grid-how-it-works-and-barriers-to-adoption/> and <https://enabler.com/resource/v2g-challenges-and-risks>

Vehicle-to-grid is still largely at pilot scale despite over a decade of proven technical viability.

4.4 Heat pumps: The central building decarbonization technology

Heating accounts for ~50% of EU final energy consumption and over 70% still comes from fossil fuels.

Technological efficiency & innovation

Heat pumps offer vastly superior thermodynamic performance compared to standard resistive direct electric heating. While direct electric systems achieve a maximum coefficient of performance (COP) of 1.0 (converting 1 kW of electricity into 1 kW of heat), modern heat pumps routinely deliver COPs of 3.0–4.5 under standard operations, effectively transferring 3–4.5 times more heat energy than the electrical input consumed. Efficiency increases further with advanced air-to-water systems tied into shallow geothermal loop water networks, which tap into stable underground aquifer temperatures to maintain optimal performance even during periods of extreme atmospheric frost.⁷³ Moreover, heat pumps are reversible, providing heat in winter and refreshed air in summer.

Current regional deployment and 2030 projections

European Union: Driven by legislative decarbonization mandates and volatile gas prices, the EU’s heat pump stock sits at ~24 million units, with conservative forecasts aiming for over 45 million operational units by 2030 despite near-term subsidy rollbacks in some states.⁷⁴

United States: U.S. heat pump stock now stands at over 23 million systems, having grown steadily since heat pumps began outselling

⁷³International Energy Agency (IEA), ‘The Future of Heat Pumps’ / Technology Deep-Dive on Aquifer Geothermal Integration.

⁷⁴European Heat Pump Association (EHPA) Market Report & 2030 Policy Target Update/Integration.

⁷⁵<https://rmi.org/insight/tracking-the-heat-pump-water-heater-market-in-the-united-states/>

⁷⁶<https://rmi.org/what-a-20-million-heat-pump-commitment-means-for-the-us/>

gas furnaces in 2021.⁷⁵ A 25-state coalition (the U.S. Climate Alliance) has separately pledged to quadruple heat pump installations in their geographies by 2030⁷⁶, though the IRA tax credit that helped drive recent growth expired at the end of 2025.

China: China represents the single largest manufacturing and domestic installation baseline globally, with over 35 million installed systems. Focused on building-density electrification, domestic stock is on track to reach more than 70 million units by 2030.⁷⁷

Macroeconomic & structural drivers

Four catalysts are accelerating global heat pump adoption curves:

Sustained high fossil fuel prices: Lingered fossil fuel price shocks make high-efficiency electric thermal solutions heavily competitive against traditional oil and natural gas boilers.

Climate-induced heat waves and reversibility: Exceptional, intensifying summer heat waves probably tied to global climate change have shifted consumer priorities. Because heat pumps feature structural reversibility, a single asset serves as both an ultra-efficient winter heater and an indispensable summer air conditioner.

National sovereignty policies: Heat pumps boost energy sovereignty by replacing imported fossil fuels with domestically produced electricity to meet heating needs. Thus, many countries allocate subsidies for heat pumps (see Table 4).⁷⁸

Demand side flexibility: With 60 million heat pumps across Europe by 2030, demand flexibility from the buildings sector could provide 20–40 GW of virtual storage—a significant contribution to managing solar surplus that drives negative prices.⁷⁹

⁷⁷China Energy Storage & Electrification CAICT Infrastructure Data Tracking Brief.

⁷⁸Bloomberg NEF, ‘Decarbonizing Buildings: Global Heat Pump Climatic Drivers and Price Shock Adaptation’.

⁷⁹BNEF Energy Storage Market Outlook 2025.



The net outlook:

Heat pump adoption will keep accelerating on efficiency, reversibility and energy-sovereignty grounds, but reaching the most optimistic 2030 targets will depend on subsidy continuity, upfront cost reduction, and installer capacity—all of which remain uneven across markets. However, as with EVs, the overall direction is clear

4.5 Data centers and AI: The new dominant electricity demand driver

Generative AI moved from a niche research curiosity to a mainstream enterprise and consumer tool in barely three years. The hyperscalers' response has been to invest at a pace with few precedents in industrial history. The largest cloud and technology companies are now racing to build large data centers. Electricity availability and chip supplies are the binding constraint on how fast AI services can scale.

AI infrastructure build-out is not a U.S.-only phenomenon, it is a global CapEx cycle

In the U.S., the scale of the response is unprecedented. The four largest U.S. hyperscalers—Amazon, Microsoft, Alphabet (Google), and Meta—guided to date, a combined 2026 capital expenditure of roughly \$700–725 billion⁸⁰, up more than 75% from approximately \$400 billion in 2025.⁸¹ The overwhelming majority of investments is directed at AI data center construction, power procurement, and chip deployment. Stargate, the joint venture between OpenAI, SoftBank, Oracle, and MGX, announced in January 2025, targets up to \$500 billion in AI infrastructure investment in the United States by 2029.⁸²

⁸⁰<https://valueadvc.com/blog/big-tech-ai-capex-in-2025-microsoft-google-meta-amazon-and-the-spending-race>
⁸¹<https://www.tomshardware.com/tech-industry/big-tech/big-techs-ai-spending-plans-reach-725-billion>

⁸²<https://openai.com/index/announcing-the-stargate-project/>

⁸³https://en.ndrc.gov.cn/news/mediar/sources/202202/t20220218_1315947.html

In China; State-backed initiatives, like the “Eastern Data, Western Computing” program launched by the National Development and Reform Commission (NDRC) in 2022⁸³, are driving major capitalization in China's data centers, with state-sanctioned hubs alone projected at up to \$63 billion/year. Investment isn't purely state-directed, as China's four largest internet companies—Alibaba, Tencent, ByteDance, and Baidu—are committing to a combined \$84 billion in AI infrastructure investment by 2027.⁸⁴ That's a 60% jump from 2025 levels, and it's happening while profits are under pressure and cloud businesses are only just turning profitable.

Europe's data center buildout totals a ~\$114 billion pipeline by the end of the decade, with electricity demand growing around 15% annually. Frankfurt, London, Amsterdam, Paris, and Dublin (FLAP-D) will remain Europe's core hubs, even as land, power, and regulatory and policy limitations challenge their dominance. Over time, growth could shift to other regions which offer grid access without the typical constraints of major metropolitan areas.⁸⁵

Japan's market, though smaller, is accelerating fast: SoftBank's Hokkaido campus, Blackstone's ~\$30 billion commitment, and Microsoft's \$2.9 billion investment are pushing the sector from ~\$6.3 billion in 2025 toward a forecast of \$59 billion by 2035.⁸⁶ However, land scarcity, construction costs, and power availability are important limitation factors.

India: Private investments are dramatic: Reliance and Adani jointly pledged ~\$210 billion for hyperscale AI data centers in February 2026, aiming to build a \$250 billion domestic AI infrastructure ecosystem.⁸⁷

⁸⁴<https://www.jonpeddie.com/news/data-center-build-out-in-china/>

⁸⁵<https://www.datacenterknowledge.com/data-center-site-selection/ai-demand-and-policy-shifts-redraw-europe-s-data-center-map-for-2026>

⁸⁶<https://www.datamintelligence.com/research-report/japan-ai-data-center-market>

The two facets of AI: AI is both the cause of surging data center electricity and water demand and an important tool for moderating its resource footprint.

AI-driven systems (like Google DeepMind's data center controller) continuously analyze sensor data, including temperature, humidity, pump speeds, and weather forecasts, to dynamically adjust cooling systems in real time, cutting cooling-related energy use by up to 40% in pilot deployments. AI also optimizes workload placement and scheduling, shifting compute to times/locations with cheaper or cleaner power, and improves water efficiency by precisely matching evaporative cooling to actual thermal load rather than fixed setpoints. Some hyperscalers are now using AI predictively to pre-cool facilities ahead of demand spikes, further reducing both energy and water draw.



⁸⁷<https://www.lightreading.com/ai-machine-learning/reliance-and-adani-commit-210b-to-make-india-an-ai-infra-hub>



Table 6 — Global data center electricity capacity by region, 2025 vs 2030 estimate. U.S. and China together account for ~80% of total global growth.⁸⁸

Region	Base capacity (2025)	Projected 2030 capacity	Primary structural drivers & constraints
United States	~54 GW	90 – 106 GW	Massive hyper-scaler buildout (Virginia, Texas, Midwest); heavily constrained by transmission queue wait times.
China	~20 GW	60 GW	Governed by state-backed infrastructure plans, private initiatives and high-density, centralized computing clusters.
Europe (EMEA)	~21 GW	34 – 38 GW	Concentrated in FLAP-D hubs. Grid connexion issues favour brown field on land with grid access.
Japan	~2.3 GW	3.7 – 5.0 GW	Accelerating to support localized sovereign AI networks and cloud regional availability zones.
Canada	~1.5 GW	3.5 – 4.5 GW	Targeted for non-latency critical training workloads due to cool climates and clean green energy mix.

Data centers’ rapid expansion is straining electrical grids systems

Data centres’ rapid, high-density expansion is straining power systems. According to a recent study by the Capgemini Research Institute⁸⁹, 83% of data-center executives and 70% of electricity executives expect AI-led sites to significantly increase regional demand within 3–5 years, with nearly 80% of utilities anticipating far more volatile, “peaky” load patterns.

The bottleneck is increasingly the grid itself rather than generation: 76–84% of power executives cite slow permitting and lengthy interconnection studies as binding constraints, compounded by aging infrastructure and thinning reserve margins.

In the U.S., this shows up concretely in the interconnection queue, where roughly 2,600 GW of proposed capacity were waiting for grid connection at the end of 2025, with median wait times now exceeding five years.⁹⁰

Demand is also geographically clustered, with over half of electricity executives flagging localized “hot spot” clustering of new data centres as a major reliability risk. At the same time, roughly one-fifth of load requests are believed to be speculative, complicating capacity planning and risking stranded assets.

Off-grid power solutions

In response to grid connection difficulties, data centers are increasingly bypassing the grids⁹¹: 29% already deploy on-site or behind-the-meter generation and a further 39% plan to do so within one to two years—a shift that risks fragmenting grid visibility and control even as it relieves near-term pressure.

These off-grid power solutions differ on time scale, size, and land availability.

Immediate: Bloom Energy⁹² solid oxide fuel cells, which deploy in weeks, can provide data center power independently of the congested grid.

Quick: U.S. data centers are increasingly turning to on-site gas turbines to bypass grid interconnection delays, but they’re running into a manufacturing bottleneck of their own: turbine makers. GE Vernova, Siemens Energy, and Mitsubishi Heavy Industries are booked solid through 2028, with lead times now exceeding three years.⁹³

This gas-power buildout appears to be showing up in Big Tech’s own emissions data: Microsoft reported a 25% jump in carbon emissions in 2025, driven mainly by data-center construction and its pause on certain renewable energy credit purchases; and Alphabet observed a 48% emissions increase since 2019 on similar AI-driven data-center growth.⁹⁴ As Microsoft’s leadership put it, “sustainability solutions are not scaling fast enough to meet demand.”

These decisions run counter to many companies’ net-zero pledges, but speed-to-power is winning out.

⁸⁸Synergy Research Group; McKinsey & Company / Goldman Sachs Research

⁸⁹https://www.capgemini.com/wp-content/uploads/2026/06/CRI_Data-centers_V10_interactive.pdf

⁹⁰<https://emp.lbl.gov/news/backlog-power-plants-seeking-transmission-grid-connection-eased-somewhat-2025-amidst>

⁹¹https://www.capgemini.com/wp-content/uploads/2026/06/CRI_Data-centers_V10_interactive.pdf

⁹²<https://www.bloomenergy.com/>

⁹³<https://www.power-eng.com/gas/turbines/data-centers-drive-record-surge-in-ge-vernova-power-equipment-orders-as-turbine-slots-tighten-through-2030/>

⁹⁴<https://fortune.com/2026/07/09/microsoft-carbon-emissions-2025-data-centers/>



Short term: (2026-2027) Co-located solar, wind and battery energy storage systems (BESS). Chinese technology and industrial leaders are pioneering the integrated deployment of these low-carbon energy systems:

- **Envision and Tencent** have jointly built what they describe as “the world’s first 100% green power direct-supply data center”. Located in Chifeng, part of Inner Mongolia’s Gobi Desert region, it combines onsite wind, solar, and battery storage via Envision’s smart microgrid controls to cut energy costs by over 40% and avoid an estimated 180,000 tonnes of CO₂ annually. It sits within Envisions broader ‘Mission Gobi’ initiative, which targets 5 GW of similar green AI data center capacity across desert regions by 2030.⁹⁵
- **The Shanghai Lingang Subsea Project:** Co-developed by China Communications Construction and HiCloud Technology, this 24 MW capacity commercial underwater data center is located 10 meters below the surface of the water and is directly powered by an adjacent offshore wind farm. Submersion eliminates the land footprint, harvests natural ocean water for cooling and thus lowers baseline power usage by more than 20%.⁹⁶
- **Datang Hubei Storage & Data Systems:** Serving as a prominent example of off-grid scaling, Datang Group implemented a grid-scale microgrid paired with a 100 MWh sodium-ion battery station which mitigates the intermittency of localized green generation for AI server arrays without traditional lithium constraints.⁹⁷

Medium-term (2030–2035): Nuclear power provides the 24/7 uninterrupted green power that renewables cannot deliver at data center scale. All four hyperscalers have committed to it: Google (Kairos Power, 500 MW SMRs)⁹⁸, Meta (Oklo Aurora, 1.2 GW, Ohio)⁹⁹, Microsoft

(Three-Mile Island restart, 835 MW)¹⁰⁰, and Amazon (X-energy, 5 GW HTGRs).¹⁰¹

The policy gap remains acute: Data centers are built in 2–3 years; the energy infrastructure that serves them takes 10–15 years. A large-scale interconnection reform is the structural prerequisite (see chapter 5).

Data centers and rising retail electricity prices

Beyond the macro demand forecasts, data centers are demonstrably raising retail electricity prices in specific regions.

In the PJM region, which includes Virginia, Pennsylvania, Maryland, and Ohio—and is the largest data center cluster in the U.S.—the independent market watchdog Monitoring Analytics concluded in June 2025 that a majority of the region’s increased capacity payments for the 2025/2026 delivery year were directly attributable to data center demand.¹⁰² These capacity payments (see §5.5) are partially flowing through to retail electricity bills, with up to double-digit percentage increases reported in several PJM states, including Maryland and New Jersey.¹⁰³

A 2025 academic study by Georgia Tech found that new data center interconnections raise wholesale electricity prices by an average of 7.3%, driven primarily by congestion.¹⁰⁴

The regulatory response has begun: Texas, Oregon, California, Georgia, Ohio, Indiana, and Utah have each introduced or enacted legislation requiring data centers to bear the incremental generation, transmission, and distribution costs their load imposes on the grid, rather than socializing these costs across all ratepayers.¹⁰⁵

Ireland, where data centers consumed over one-fifth of the country’s entire electricity in 2024, went further: regulators imposed a moratorium on new connections and, upon lifting it, now require new large energy users to install on-site (behind-the-meter) generation or storage and meet a rising share of demand with additional renewables as a condition of approval.¹⁰⁶

The electricity cost increase triggered by large data center construction and operation requires regulatory solutions in order to avoid or limit impact to retail customers’ electricity prices.

“Trees don’t grow to the sky”¹⁰⁷: Why the surge has limits

The data center electricity surge is real, but several structural constraints mean that the most extreme forecasts are likely to be moderated¹⁰⁸:

- **Revenue-investment gap:** The AI industry needed approximately \$600 billion in annual revenue to justify its 2024–2025 investment pace. This falls short of actual AI-specific revenues of approximately \$100 billion.¹⁰⁹ This gap will moderate capital expenditure growth as investors demand returns.
- **The DeepSeek moment (January 2025):** China’s R1 model matched leading U.S. AI systems at a training cost of approximately \$6 million versus more than \$100 million for comparable U.S. models.¹¹⁰ Algorithmic efficiency improvements could reduce the energy intensity of AI inference by 50–80% over the next three years, fundamentally shifting the electricity demand trajectory.

⁹⁵<https://finance.biggo.com/news/7c3c1391-47df-4a48-b00a-f78edcda4302>

⁹⁶China Daily / International Marine Infrastructure Engineering Insights — Tracking subsea commercial data network deployments and offshore wind power links.

⁹⁷Energy-Storage-News / PatSnap Industrial Analytics Market Briefing — Sodium-ion commercial grid-scale data backup architectures and microgrid optimization.

⁹⁸<https://www.kairopower.com/updates/google-and-kairos-power-partner-to-deploy-500-mw-of-clean-electricity-generation>

⁹⁹<https://www.world-nuclear-news.org/articles/meta-announces-landmark-agreements-for-new-nuclear>

¹⁰⁰<https://www.orrck.com/en/News/2024/10/Microsoft-Signs-20-Year-PPA-with-Constellation>

¹⁰¹<https://www.powermag.com/amazon-backs-massive-nuclear-smr-deployment-5-gw-with-x-energy-agreements-with-energy-northwest-dominion/>

¹⁰²Monitoring Analytics, “Analysis of the 2025/2026 RPM Base Residual Auction” (June 2025). The Independent Market Monitor for PJM attributed 63% of the year-over-year increase in capacity prices for the 2025/2026 delivery year to data centre load growth (approx. \$9.3 billion of the increase); See also Union of Concerned Scientists, “Connection Costs Loophole Costs Customers Over \$4 Billion” (Sept. 2025), on related transmission cost pass-through.

¹⁰³E&E News/POLITICO, “Data center boom sparks sticker shock for PJM ratepayers” (2025); Utility Dive, “Data centers ‘primary reason’ for high PJM capacity prices: market monitor”; NRDC, “Rising Demand from Data Centers Driving Reliability, Cost Concerns,” estimating up to \$70/month in added costs for an average PJM household by 2028.

¹⁰⁴J. Mamkhezri et al., “The Hidden Cost of the Cloud: Data Centers and Electricity Market Inefficiency,” Georgia Tech Energy Policy and Innovation Center (EPICenter), 2025.



- **Grid connection crisis:** In the US, 2,600 GW of projects are grid connection queue. Between 7% and 20% of planned data center projects are delayed by grid bottlenecks.¹¹¹
- **Semiconductor fragility:** A geopolitical rupture affecting TSMC’s Taiwan fabs or ASML’s EUV lithography equipment supply could halt the entire AI chip build-out within 12–18 months.¹¹²

The table below shows new data centers’ estimated completion rates and limitations due to power availability.

Table 7 — New data center grid connection completion rates by region (May 2026)¹¹³

Region	Estimated completion rate	Operational realities & interconnection context
United States	~20%	In major transmission zones like PJM, the queue of pending energy requests exceeds 2,600 GW. Historically, only ~20% of proposed projects clear the interconnection process, facing a median wait time of five years.
Europe	~30% – 40%	Rigid regulations and environmental moratoriums restrict rapid rollouts. Grid connection delays for large data center campuses range from three years (Italy) up to a staggering 10 years (United Kingdom).
China	~65% – 75%	Exhibits significantly higher completion rates due to synchronized state infrastructure planning.
Japan & Canada	~50%	Japan faces land scarcity and steep power costs, requiring specialized power architecture. Canada offers rich hydro assets, but provincial utilities (e.g., Hydro-Québec) are tightening allocations to protect consumer baseload.

Data center electricity growth is the most important new variable in global power markets. It triggers large investments but poses new challenges to the grid, forcing operators to deploy off-grid solutions. But “trees don’t grow to the sky.” Algorithmic efficiency, revenue discipline, and grid bottlenecks will moderate the most extreme forecasts.

Data centers in space: Why it remains premature

In 2025, Elon Musk’s SpaceX floated the concept of orbital data centres—facilities placed in low earth orbit (LEO), powered by direct solar radiation (which is eight times more intense than on Earth’s surface and available 24/7 without atmospheric loss) and cooled directly into the cold of space. The concept has genuine long-term appeal: it sidesteps terrestrial land constraints, grid connection queues, and the water

consumption of conventional data center cooling. Musk’s framing was characteristically bold—orbital infrastructure is the answer to the terrestrial power problem.¹¹⁴

Engineering economics tell a different story. Launching mass to LEO costs \$1,000–2,000/kg even with the most optimized Starship manifests, and a 1 MW data center facility requires approximately 5,000–10,000 kilograms of hardware (servers, power systems, thermal radiators). That implies a launch cost of \$5–20 billion per megawatt of computing capacity, versus \$2–5 million per MW for a terrestrial data center. Latency compounds the problem: the round-trip communication delay from LEO to a terrestrial user (minimum 5–10 milliseconds per pass) makes orbital facilities unsuitable for the latency-sensitive inference workloads that constitute the majority of AI computing demand. Data must also be transmitted to and from the ground at high bandwidth, a further engineering and spectrum constraint. Radiation hardening requirements for electronics increase hardware costs by a factor of 10–100 over commercial equivalents.¹¹⁵

Conclusion:

Orbital data centers are a conceptually interesting long-term option for specialized high-value workloads, such as scientific computing and government/defense applications, where latency is not critical and the orbital power advantage justifies the cost premium. They are not a credible answer to the 2025–2030 data center power crisis.

¹⁰⁵ArentFox Schiff, “State Regulation of Data Centers in 2026 – A Shifting Landscape”; MultiState, “State Data Center Legislation in 2026 Tackles Energy and Tax Issues”; Latitude Media, “State lawmakers stand between ratepayers and data center costs.” Key measures: Texas SB 6 (2025, large-load interconnection cost allocation); Oregon POWER Act (2025, separate large-load rate class); Ohio PUCO-approved AEP Ohio large-load tariff; Utah SB 132; Georgia SB 34.

¹⁰⁶Commission for Regulation of Utilities (CRU), “Large Energy User Connection Policy” (final decision, Dec. 2025); RTE, “80% of data centre energy must come from renewables – CRU”; Reuters/Energy Connects, “Ireland Ends Moratorium on New Power Links to Data Centers” (Dec. 2025).

¹⁰⁷German proverb: “Es ist dafür gesorgt, dass die Bäume nicht in den Himmel wachsen”

¹⁰⁸WEMO 2026 analysis; IEA; McKinsey & Company; Bloom Energy; US DOE grid connection queue data.

¹⁰⁹Sequoia Capital, “AI’s \$600B Question” (2025): annual AI infrastructure spend of ~\$600bn requires ~\$600bn in matching revenue; actual AI-specific revenue estimated near \$100bn.

¹¹⁰DeepSeek-V3/R1 technical reports citing ~\$5.6–6.3m training compute cost versus \$100m+ reported for comparable US frontier models (Sam Altman, 2023 remarks).

¹¹¹Lawrence Berkeley National Laboratory, “Queued Up: 2025 Edition” (interconnection queue data); Sightline Climate, “Data Center Outlook”; Latitude Media, “Up to half of the world’s data centers may be delayed this year” (2026).

¹¹²Digital Statecraft, “The Global Compute Bottleneck: Chips, TSMC, and the Fragility of the AI Supply Chain” (2026); ASML Q1 2026 order backlog disclosures (record 45 EUV systems).

¹¹³IEA Special Report, “Data Center Power Demand”; Rystad Energy Analysis; Wood Mackenzie / Ceres Technology Report; Brookings Institution (see also Table 9).

¹¹⁴NPR, “Big Tech’s next move is to put data centers in space. Can it work?” (3 April 2026).

¹¹⁵Wikipedia, “Space-based data center”; SpaceX — Orbital Datacenters: Economics and Physics, “Endtropy (2026); BlackKnight Space Labs, “Orbital Data Centers Explained” (2026).



05

Electrical grid challenges





Electricity grids are the backbone of the energy transition¹¹⁶

After analyzing the present electrical grid challenges we will now turn to technical, social, and regulatory solutions.

5.1 Grid investments: Considerable needs, difficult delivery

Reaching national energy transition plans requires adding or refurbishing more than 80 million kilometers of grid by 2040—an area equal to the entire existing global network—with investment needs exceeding \$500 billion per year by 2030.¹¹⁷ Investments are funded through subsidies, private funding, and grid tariffs, but tariff increases are capped by regulators, and tariff structures prioritize hardware solutions over cheaper smart grid and grid enhancement technology (GET) solutions.

Moreover, building new physical transmission infrastructure remains a massive bottleneck globally. A standard high-voltage overhead line, such as a 345 kV to 765 kV AC, or an advanced HVDC line, faces drastically different deployment speeds and economic realities depending on the region.

5.2 Intermittency: Challenges and consequences

The increasing percentage of intermittent renewables in the electricity mix, plus electrification of heating, transport, and industry, are making generation more weather-dependent and demand peakier as EV charging, heat pumps and data centers all add concentrated load. Wind and solar carry a structural challenge: they produce electricity only when wind blows or sun shines. A grid with 50% installed

renewable capacity may, on a still winter night, generate close to zero renewable electricity, forcing near-100% backup capacity to be maintained.

The table below summarizes the challenges and indicated solutions.
Table 8 — Intermittency dimensions and grid consequences

Dimension / challenge	Analysis	Impact
Daily variability (hours)	Solar produces zero at night. Wind fluctuates hourly and can vary by 90% within a single day. Battery storage (4-hour systems) can address daily cycles but adds cost.	High
Seasonal variability (weeks/months)	Solar peaks in summer—the inverse of heating demand. Seasonal storage remains economically prohibitive at current technology and cost levels.	Very high
Dunkelflaute ('dark calms') ^{118 119}	Anti-cyclonic events affect entire continental regions for 1–2 weeks. In January 2025, Europe experienced nine consecutive dark-calm days with near-zero renewable generation. ¹²⁰	Critical
Backup capacity required	Even with 80% renewable energy, a grid must maintain near-100% backup capacity. Today, that backup is almost always natural gas.	High
Grid frequency stability	Synchronous generators provide inertia. Wind and solar inverters do not. At high penetration, flywheels, synchronous condensers or grid-forming inverters become necessary.	High
Price cannibalization	When it is sunny and windy simultaneously, renewable output floods the market and spot prices go negative, reducing returns on investment and slowing deployment.	High
The "last 20%" problem	Getting from 80% to 100% clean electricity is disproportionately expensive. The final 20% requires massive seasonal storage, continental transmission, or firm clean power.	Critical

¹¹⁸Note: the most rigorously documented 9-day European 'dark calm' event on record occurred 16–25 January 2017 (wind+solar of 91 GW capacity falling to ~4.6 GW output),
¹¹⁹December 2024 also saw a widely reported multi-day Dunkelflaute that pushed German power prices to a two-decade high (Fortune, 12 Dec 2024).
¹²⁰Need information

After reviewing the root causes of the 2025 Iberian blackout, we will take a deep dive into some solutions: BESS, demand-side flexibility, grid connection queue reform, and the benefits of AI usage.

5.3 The April 28, 2025 Iberian blackout: Cause and warning

At 12:33 CEST on April 28, 2025, the power systems of mainland Spain and Portugal collapsed: 47 million people were without power for up to 18 hours, causing eight deaths and €1.6 billion in economic damage.¹²¹ Solar was supplying more than half of Spain's demand when a voltage surge triggered overvoltage protection relays across the solar fleet, disconnecting 2.5 GW of photovoltaic solar in under three seconds.

The definitive triggers of the April 2025 major blackout in Spain remain unresolved; subsequent reports offer conflicting conclusions, shifting responsibility among power generators, grid operators, and regulatory bodies depending on the issuing entity. Because the final allocation of responsibility will dictate massive consequential damage payments, every sector is actively defending its position, as no stakeholder wants to be held legally or financially liable.

The ENTSO-E final report identified four failures: a thermal plant requested to provide voltage support did not show up; pre-warning voltage oscillations on April 16, 22, and 24 were not acted upon; Spain's automatic defense plans were designed for frequency crises, not fast overvoltage cascades; and Spain's structural isolation (~3 GW interconnection with France) prevented external stabilization.¹²²

¹¹⁶As I wrote in my last's year's outlook <https://www.capgemini.com/insights/research-library/world-energy-markets-outlook/>
¹¹⁷IEA, "Electricity Grids and Secure Energy Transitions" (2024/2025): 80 million km of grid additions/refurbishment needed by 2040; note IEA's own updated estimate calls for grid investment to nearly double to over \$600bn/year by 2030.
¹²¹Wikipedia, "2025 Iberian Peninsula blackout"; ENTSO-E, "28 April 2025 Blackout" incident page; economic loss estimate per CEOE (Spanish employers' confederation), as reported in Insurance Journal, "Companies Count the Costs After Blackout in Spain and Portugal" (30 April 2025) — other estimates range from €400m (CaixaBank) to €4bn+; casualty count (8 deaths) per ENTSO-E Expert Panel final report.
¹²²ENTSO-E Final Report on the Iberian Blackout, 20 March 2026.



“

The problem is not renewable energy, but voltage control, regardless of the type of generation.

Damián Cortinas, Chair of the ENTSO-E Board,
Press Briefing, March 20, 2026

Despite those declarations, experts believe that the high proportion of electricity generated by solar farms and their partial disconnection seconds before the blackout are one of the causes of this accident.

On a more technical level, Spain's solar inverters were technically capable of actively regulating voltage by adjusting their reactive power output. However, Spanish grid regulations required these inverters to operate in a fixed, passive power-factor mode—meaning they could not dynamically inject or absorb reactive power to help stabilize voltage during the disturbance. Thus, the blackout was partly a regulatory choice.

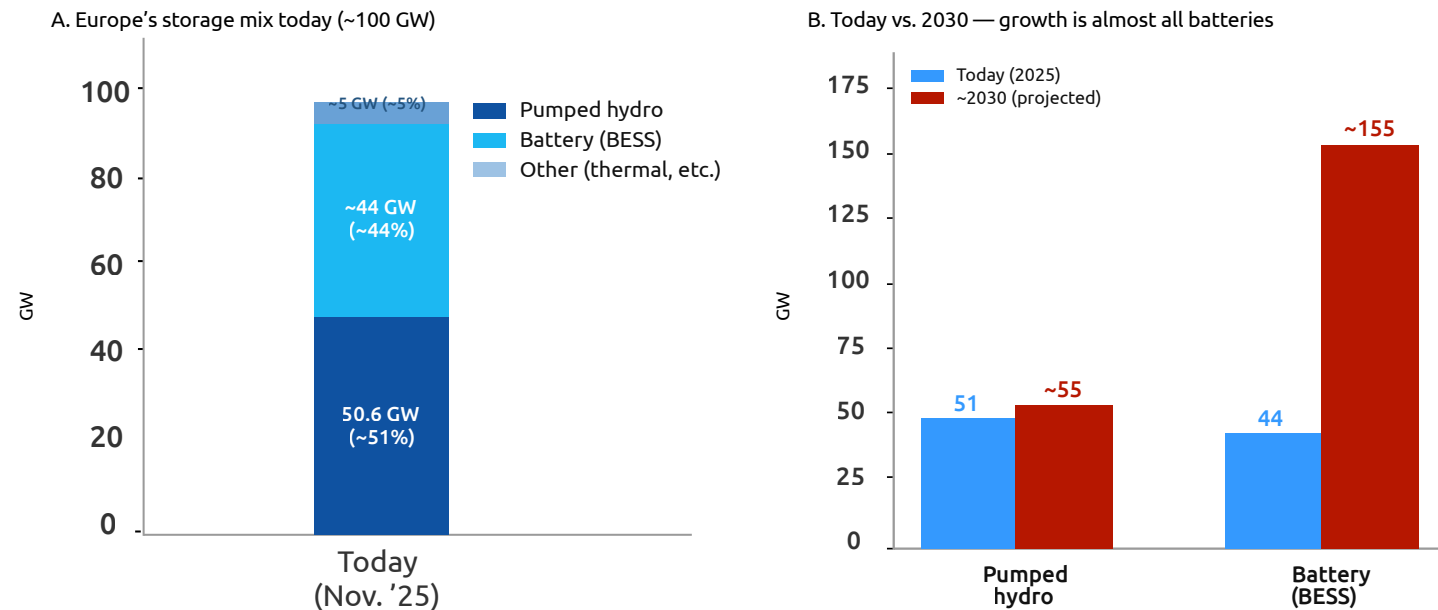
5.4 EU storage mix to evolve from a dominance of pumped hydro to a dominance of battery storage

Of the ~100 GW storage installed (EU/U.K./Norway/Switzerland), pumped hydro remains the largest single technology (~50.6 GW, ~51%), with BESS close behind (~44 GW, ~44%) and other technologies a small residual (~5 GW). Growth to 2030 is overwhelmingly battery-led: ~128 GW of new battery storage is expected, versus only marginal new pumped hydro, due to site constraints and long lead times.¹²³

Worldwide BESS deployment has accelerated dramatically, from 43 GWh in 2022 to 205 GWh in 2024, an increase of 53%. In 2025, deployments grew to ~315 GWh, an increase of more than 50%, and total operational capacity exceeded 375 GWh. Meanwhile, battery pack prices fell dramatically by 84% since 2015.¹²⁵

Figure 14

Europe's storage mix today and projected to 2030¹²⁴



¹²³EASE / LCP Delta, EMMES 9.0/9.5: pumped hydro ~50.6 GW, battery (BESS) ~44 GW, other ~5 GW; an additional ~128 GW/300 GWh of electrochemical storage expected by 2030 vs. only marginal new pumped hydro. European Commission, "Key facts on energy storage" confirms the same 2030 electrochemical-storage addition.

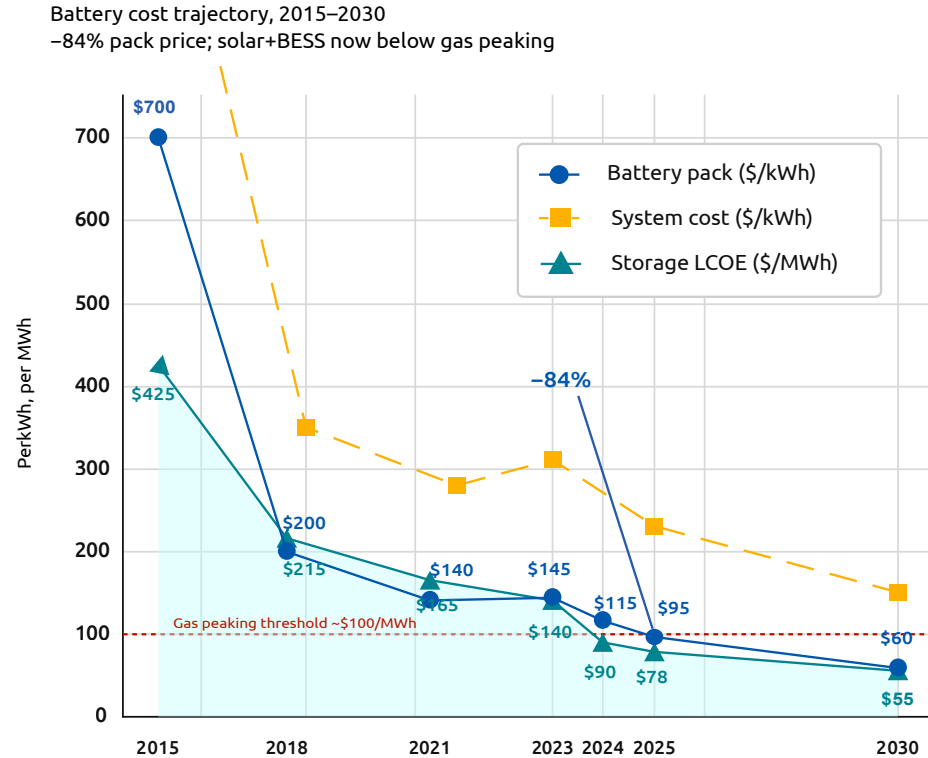
¹²⁴EASE / LCP Delta EMMES 9.0/9.5; European Commission; Bruegel; SmartEn; ENTSO-E.

¹²⁵BloombergNEF, Energy Storage Market Outlook 2025; Energy-Storage.News, "Global BESS deployments soared 53% in 2024"; pv magazine, "Global grid-scale BESS deployment rises 38% through October" (2025) — note tracked 2025 additions of ~200–220 GWh (+26–38%) run somewhat below the ~315 GWh (+50%) figure used in the text.

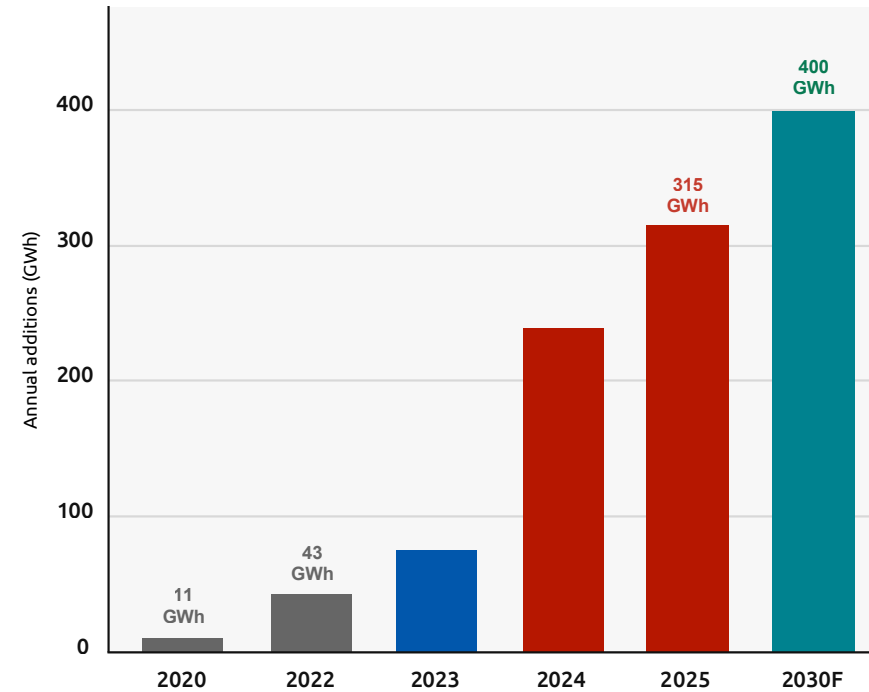


Figure 15

Battery cost trajectory (2015–2030) and global BESS annual additions. LFP chemistry now represents 73% of all deployments.



Global BESS annual additions (GWh)
67% average annual growth rate over past decade



Sources: BNEF Energy Storage Market Outlook 2025; Rystad Energy BESS Outlook 2025; Ember Global Electricity Review 2025. 2030 = BNEF base case forecast.

Storage duration limits: Today's grid-scale BESS averages 2–3 hours—ideal for daily solar arbitrage but not a protection against a 9-day period with no sun and wind. BESS is the ideal daily complement to renewables, not a substitute for dispatchable clean power at multi-week timescales. Nuclear, hydro, and geothermal must complement BESS.



5.5 Demand-side flexibility (DSF): The underused lever

Capacity mechanisms: The broader context for firm capacity

Before turning to DSF and storage, it is worth recalling where they sit within the EU's wider toolkit for ensuring security of supply. A capacity mechanism is a national policy that pays generators, energy storage operators and demand-response providers to remain available during periods of system stress, in addition to the revenue they earn from selling electricity. Its purpose is to ensure sufficient firm capacity is available to meet peak demand, even when wind and solar generation is low. Roughly two-thirds of EU countries now run one, including France, Italy, Poland, Belgium, Ireland, and Germany's strategic reserve, among others. However each capacity mechanism is designed and procured nationally rather than through a single EU-wide market.

Across these mechanisms, around 178 GW of firm capacity was remunerated in the European Union in 2024. Gas accounted for the largest share (approximately 57 GW, or 32%), followed by nuclear (44 GW, or 25%). Demand response and battery storage together represented just 8 GW, or 4.5% of the total, up from around 5 GW (3%) in 2023 but still a relatively small share of the firm-capacity mix.¹²⁷

DSF solutions, aggregation, and virtual power plants

Today's EU baseline and 2030 needs

- DSF EU enabling rules date to 2019, but the Network Code for Demand Response is still not adopted, having been under Commission review since March 2025; binding national targets aren't due until January 2027.¹²⁸

- Storage reached ~100 GW installed in Nov. 2025 (Figure 14), about half the 200 GW 2030 target¹²⁹, the majority of which will be provided by BESS.
- Flexibility needs should roughly double from 2025 to 2033 (ENTSO-E).¹³⁰
- DSF could supply ~160 GW up / ~130 GW down by 2030 (Smart-En).¹³¹

1. Demand-side response (DSR) is the mechanism by which consumers, households, or businesses, adjust their electricity consumption (shifting or briefly curtailing it) in response to a grid or price signal. It is usually via automated control of an appliance such as a heater or water tank. For example, Voltalis is a DSR specialist: it controls the end-use device directly by installing a free smart box that briefly interrupts heating, water heaters, or air conditioning on a TSO signal, imperceptibly to the consumer. Presently, it has installed 1.5 million appliances across ~250,000 buildings, mostly in France and expanding into other EU countries and the U.K.¹³²

2. An aggregator pools many small, distributed sources of flexible demand or generation across multiple sites—and often multiple owners—into a single portfolio large enough to participate in wholesale, balancing or capacity markets. An aggregator, such as EDF subsidiary Agregio Solutions, does not necessarily own or control end-use devices. Instead, it contracts with asset owners and aggregates their flexible capacity for participation in wholesale, balancing and capacity markets. The aggregation model is distinct from direct DSR control.

3. A virtual power plant (VPP) aggregates distributed assets such as batteries, hydro, and demand response, as a single dispatchable resource.

One example is EDF Power Solutions' Stockage Énergie Catalan (SEC) facility in Baixas, its first utility-scale battery energy storage site in metropolitan France. Key features include:

- 28 MW of capacity, combining 20 MW of lithium-ion batteries with 8 MW from 10 hydroelectric dams, coordinated in real time using AI.¹³³
- Sub-second response times, with batteries reaching full power in 30 seconds and hydropower providing support for up to 15 minutes.

Conclusion:

In Europe, grid flexibility needs should roughly double from 2025 to 2033, and the directives (e.g., Network Code, national assessments, and binding targets) should switch on in 2026–2027. Demand side flexibility and storage are where the fastest, cheapest gains in flexibility lie. Member States must formally assess it and set targets to increase these flexibility resources.

5.6 Grid connection queue reform

Grid connection queues have become the primary bottleneck for renewables deployment as well as for data centers (see above). Europe has 375 GW of renewables and 455 GW of battery storage farms waiting for a grid connection¹³⁴, with some sources revealing higher figures.¹³⁵ The U.S. queue exceeded 2,000 GW at the end of 2023, with average wait times of over five years.¹³⁶

¹²⁷ACER, "Total capacity remunerated in EU capacity mechanisms, per type of technology" (2020–2024), based on data from National Regulatory Authorities and the ENTSO-E Transparency Platform: 2024 See also Bruegel, "Europe's electricity capacity mechanisms need to be better coordinated" (2025), citing Rodilla et al. (2023).

¹²⁸European Commission, Electricity network codes and guidelines (status May 2026): Network Code on Demand Response submitted by ACER 7 March 2025, still under Commission review — not yet adopted; national flexibility assessments due July 2026; binding national DSF/storage objectives due January 2027.

¹²⁹EASE / LCP Delta, EMMES 9.5 (Nov. 2025): EU/UK/Norway/Switzerland reached ~100 GW installed storage (vs. ~200 GW EASE target for 2030).

¹³⁰ENTSO-E, System Flexibility Needs for the Energy Transition (Dec. 2024); Report on Flexibility from Renewable Energy Sources (Nov. 2025).

¹³¹SmartEn, cited in Ember, "Making clean power flexy" (2025).

¹³²Voltalis Group press releases (2024–2026); group.voltalis.com. "1.4 GWP" is capacity financed for rollout by end-2025; Voltalis cites ~1 GWP as already operational, with the remainder under construction.

¹³³Electroniques.biz, "Une centrale virtuelle au service de l'équilibre du réseau électrique" (18 June 2026).

¹³⁴Euronews, "A €100 billion queue: Why Europeans are waiting years for clean energy" (June 2026).

¹³⁵Beyond Fossil Fuels / civil-society grid-connection-queue survey (2025): ~1,700 GW of renewable and hybrid projects queued across 16 European countries;



Five major reforms are underway:

- **European Union Grids Package (December 2025):** Introduces a “first ready, first served” approach, backed by a €30 billion Connecting Europe Facility (CEF) budget.
- **Germany’s Reifegradverfahren (April 2026):** Prioritizes projects using a maturity-based scoring system.
- **France’s PPE3 (February 2026):** Prioritizes grid access for repowering projects.
- **Great Britain’s National Energy System Operator (NESO):** Reforms connection queues, with the aim of cutting waiting times by more than half.
- **U.S. Federal Energy Regulatory Commission (FERC) Order No. 2023:** Streamlines interconnection by moving to a first-ready, first-served cluster study process.¹³⁷

5.7 The benefits of AI usage

Because physical grid construction is lengthy and capital-intensive, digital optimization is vital to enable the immediate clean energy transition.

GETs are underutilized solutions to optimize the capacity, efficiency, and reliability of existing grids. These include: dynamic line rating (DLR), advanced power flow control (APFC), intelligent asset investment planning, and transmission topology optimization. The U.S. Department of Energy is investing \$8.4 million in these advanced technologies.¹³⁸

More broadly, the integration of AI will fundamentally enhance power grid operations. For instance, by leveraging advanced meteorological forecasting, AI enables significantly more accurate predictions for intermittent renewable generation, thereby reducing the need for costly standby fossil fuel baseload.¹³⁹

Furthermore, AI algorithms optimize long-term investment decisions and macro-level planning, while helping developers navigate local construction hurdles, most notably by automating compliance checks across dense, complex regulatory frameworks. Thanks to the widespread deployment of smart grid components and IoT sensors, physical AI utilization can maximize the operational efficiency of existing networks. This optimization allows grid operators to safely squeeze more capacity out of current lines through DLR, mitigating the immediate requirement to construct new physical infrastructure.

¹³⁶Lawrence Berkeley National Laboratory, “Queued Up: 2024 Edition” (2024): nearly 2,600 GW of generation and storage capacity were in US interconnection queues as of end-2023 — more than twice the installed capacity of all US power plants (the text’s “2,000 GW” understates this slightly). Median time from interconnection request to commercial operation reached approximately 5 years for projects completed in 2023, up from under 2 years for projects built in 2000–2007.

¹³⁷<https://www.ferc.gov/explainer-interconnection-final-rule>

¹³⁸US Department of Energy, Office of Electricity, “U.S. Department of Energy Invests Nearly \$8.4 Million to Advance Grid-Enhancing Technologies” (Nov. 2023)

¹³⁹National Grid ESO (UK): AI-based forecasting models blending weather data and historical output, reported to cut renewable forecast error by approximately 30%. Xcel Energy: AI wind/solar forecasting reported to cut curtailment by approximately 20%.





06

Clean new technologies and AI adoption





6.1 Future green technologies: Technology readiness level (July 2026)

Continuous technological improvements in the design and production of photovoltaic cells, wind turbines, and batteries—combined with proactive policies—have led to dramatic cost reductions, a trend not (yet) seen with electrolyzers.

Moving forward, governments, industries and financial institutions must continue along this path by stepping up investment in research, development, and industrialization. Beyond scientific expertise, which remains crucial, accelerating the market launch of these new technologies depends on funding for laboratories and start-ups, as well as the risk appetite of potential investors. As in many other sectors, the U.S. and China have a head start.

The table below updates the TRL assessment from WEMO 2025.

Table 10 — Technology readiness levels update, May 2026. ▲ = upgraded vs WEMO 2025.

Technology	TRL 2025	TRL 2026	Key Update
Perovskite solar cells	4	▲ 5-6	World record 34.85% efficiency (April 2025). Oxford PV first modules to U.S. utility. GW-scale production expected 2027–2028.
Li-ion solid-state batteries	4-6	5-6	Toyota production approval (Oct 2025); QuantumScape QSE-5 verified. True all-solid-state broadly available only early 2030s.
Silicon anode Li-ion	7	▲ 8	Panasonic 4680 cells in Tesla production; Sila Nanotechnologies in volume (Mercedes EQG, 2025). Energy density gains 20–40% confirmed.
PEM electrolyzers	7	▲ 7-8	Global installed Proton exchange membrane (PEM) capacity exceeded 2 GW in 2025. Cost reductions 40–50% since 2020.
Small modular reactors	6-8	5-9 (widened)	Russia RTM200N operational (TRL 9); China HTR-PM commercial (TRL 8–9). Canada BWRX-300 approved (May 2025). No operating western SMR.
Nuclear fusion	2-3	▲ 3-4	SPARC tokamak under construction. ITER first plasma now 2034. \$9.7Billion raised by 53 private companies (2025).

¹⁴⁰Hydrogen Council & McKinsey & Company, “Hydrogen Insights” (2021); IEA, Global Hydrogen Review 2021. Announced project pipelines implied up to approximately 90 GW of electrolyser capacity by 2030 under optimistic industry scenarios with several analysts projecting sub-\$2/kg costs by 2030.

¹⁴¹IEA, Global Hydrogen Review 2025. Global installed electrolyser capacity reached approximately 2 GW in 2024 and exceeded approximately 3 GW by mid-2025 —Regional costs vary widely; China’s green hydrogen should be significantly cheaper than Europe/US due to lower capital costs, cheaper renewable electricity and faster permitting.

¹⁴²Eye on the Market, Michael Cembalest, J.P. Morgan, March 3, 2026.

¹⁴³Takshashila Institution, “China’s Green Hydrogen Landscape” (Nov. 2025); MacroPolo, “Can China Make Hydrogen Electrolyzers Cheap as It Did For Solar?”; Hydrogen Insight reporting on Xinjiang/Henan green hydrogen priced near \$2.24/kg (Aug. 2025) against global costs of \$5–\$12/kg.

¹⁴⁴ScienceDirect, comprehensive reviews of hydrogen liquefaction (energy losses of approximately 25–35%) and ammonia-carrier pathways (synthesis, shipping and cracking/reconversion combined can retain as little as approximately 63–64% of the original energy content).

¹⁴⁵IMO Strategy on Reduction of GHG Emissions from Ships (adopted July 2023): net-zero GHG emissions from international shipping by or around 2050, with indicative checkpoints of approximately 20% reduction by 2030 and approximately 70% by 2040, versus 2008 levels.

6.2 Green hydrogen: Why the market has not grown at the predicted pace

A decade ago, green hydrogen was heralded as the universal solvent of the energy transition, destined to decarbonize steelmaking, heavy electrical trucking, aviation, and seasonal power storage. Analysts projected over 100 GW of capacity by 2030 at costs below \$2/kg.¹⁴⁰

The reality is different: Around 3 GW of electrolyzers were operational worldwide at the end of 2025 and delivered costs ranging from \$5–12/kg—a rate three-to-six times that of grey hydrogen. The IEA estimates green hydrogen met under 0.1% of global demand in 2025.¹⁴¹

Why did hydrogen disappoint?

Three structural failures explain the gap between projection and reality.

- The cost of electricity dominates:** 70–80% of green hydrogen’s production cost is electricity. At European grid prices of €60–100/MWh, hydrogen costs \$6–10/kg, far above the \$2/kg threshold. Balance-of-plant costs (compression, purification, deoxygenation) are systematically underestimated with the electrolyzer stack itself perhaps being only 5–30% of capital costs.¹⁴² China quotes \$2–3/kg using off-grid renewables generation coupled with batteries.¹⁴³
- Long-distance transport remains unsolved:** Hydrogen has the lowest volumetric energy density of any fuel. Liquefaction consumes 30–40% of energy content; ammonia, the most viable carrier, loses 25–30% on reconversion. As a result, 99% of hydrogen produced is consumed on-site.¹⁴⁴





- **Demand never materialized at scale:** Steel producers delayed adoption; trucking found battery-electric vehicles competitive sooner than expected; and aviation favored sustainable aviation fuels (SAFs) instead. Hydrogen also faces competition from cheaper batteries and demand response.

Where hydrogen retains a role

As I wrote in my previous WEMO outlook, green hydrogen must be reserved for specific applications: (i) hard-to-abate industrial processes with no electrification alternative, such as green steel, high-temperature industrial heat above 1,000°C, and ammonia for fertilizers; and (ii) maritime fuel, particularly green ammonia, where the International Maritime Organization’s (IMO) 2050 net-zero target creates a regulatory mandate absent in other sectors.¹⁴⁵ The addressable market is real, but a fraction of the “everything, everywhere” vision of 2020–2022.

Bottom line: Green hydrogen faces a fundamental cost floor set by the price of renewable electricity and the engineering complexity of the system. It will play a targeted, but limited, role in decarbonizing industries that cannot be electrified, but it will not be the universal energy carrier once forecast.

6.3 AI in the utilities sector

AI is delivering measurable commercial value across the energy sector, particularly in grid management and renewable forecasting.

Key results from leading utilities include: Vattenfall –34% downtime; Terna –€87 million balancing costs; National Grid £340m incident prevention value; E.ON –30% outages.¹⁴⁶

¹⁴⁶Vattenfall: predictive-maintenance AI across its Nordic wind fleet (2024), –34% unplanned downtime. Terna (Italy’s TSO): AI renewable-forecasting deployment (2024), –€87m/year balancing costs. National Grid: approximately £340m estimated annual value from AI-assisted incident prevention across UK/US operations, following a £45m AI investment. E.ON: €180m cumulative operational value from AI reported for 2022–2025; the specific “–30% outages” figure in the text could not be independently verified and should be checked against E.ON’s own disclosures.

¹⁴⁷Order-of-magnitude estimate consistent with McKinsey & Company and GridWise Alliance analyses of AI-driven value creation in grid operations (predictive maintenance, forecasting, dispatch optimisation); exact figures vary by utility size and AI maturity, and a single named source for this precise range was not identified.

Table 11 — AI maturity, leading examples and barriers in the utilities sector

Domain	Maturity level (2025–26)	Key examples	Structural barriers
Grid management & BESS	Commercial scale — results proven	Vattenfall –34% downtime; Terna –€87m balancing costs; E.ON –30% outages.	Regulatory sign-off required for autonomous control; ENTSO-E technical codes constrain the speed of AI-driven switching. Results are strongest where AI assists operators, not replaces them.
Renewable generation	Commercial scale —broad adoption	Iberdrola neighborhood-to-country weather forecasting; Google DeepMind forecasting generates +20% wind value.	Weather data quality varies by market; AI-driven dispatch frameworks still being developed.
Thermal generation (nuclear, gas)	Early operational — safety constrained	EDF nuclear fuel-loading annual shutdown. AI-enabled planning shortened shutdowns by two weeks.	Nuclear safety regulations require human authority over all safety-system interactions; AI limited to monitoring and advisory functions. IEC/IAEA AI standards for nuclear remain in draft.
Retail: Pricing & demand response	Mature in leading utilities; nascent in median utilities	Octopus Kraken (15M accounts, –40% cost-to-serve); EDF Tempo AI-enhanced; Vattenfall/EDF energy advice services.	Smart meter penetration is the binding constraint. GDPR regulations on personal data limits behavioral profiling.
Corporate management (HR, procurement, GenAI)	Pilot stage — early adoption	Enel procurement AI (target €500M savings); GenAI for reporting and documentation (Gartner estimates 40% of energy firms deployed AI in 3+ business units as of mid-2024).	Union collective-bargaining agreements constrain AI-driven headcount reduction; regulatory scrutiny of algorithmic decision-making; legacy IT limits enterprise-wide data integration.

AI grid intelligence

AI grid intelligence delivers a €100–500 million annual value opportunity per major utility today.¹⁴⁷ In addition to the benefits listed in the previous paragraph, let’s mention three high-value applications:

- **Predictive models:** Reduce forecast errors by 20–30%, enabling advance scheduling of wind/solar flows.¹⁴⁸
- **Voltage control:** AI monitors thousands of nodes simultaneously. Automated regulators (that were absent in Spain’s April 2025 blackout) prevent disconnection cascades.¹⁴⁹
- **VPP networks:** Aggregating EVs, batteries, and heat pumps into dispatchable virtual plants of tens of GW (see above).¹⁵⁰

¹⁴⁸NREL (2022), analysis of AI-based solar/wind forecasting accuracy gains; National Grid ESO (UK) AI forecasting models reported to cut forecast error by approximately 30%.

¹⁴⁹On automated, AI-driven voltage/reactive-power control as a mitigant to events such as Spain’s 28 April 2025 blackout, see ENTSO-E Expert Panel, final report on the Iberian Peninsula blackout (2025), which discusses the absence of dynamic voltage support from solar inverters operating in fixed power-factor mode (see also §5.2 above).

¹⁵⁰North American VPP capacity reached approximately 37–40 GW by mid-2025. In Europe, Next Kraftwerke aggregates approximately 15.5 GW across 15,000+ assets and Sympower controls 3+ GW across six countries; Tesla’s California VPP programme mobilised approximately 70,000 enrolled home battery systems during 2025 peak events.



07

Mitigation progress and the adaptation Imperative



Climate change mitigation is lagging and adaptation is now an imperative

7.1 Emissions are continuing to grow. The Paris 1.5°C target will not be reached.

2024 total GHG emissions reached 53.2 gigatonnes of carbon dioxide equivalent (GtCO₂eq), up 1.3% year on year. Preliminary full-year 2025 data, released in February 2026 from a broader satellite-based inventory, estimated GHG emissions at approximately 60.6 GtCO₂e—a new record and a 0.5% increase over the previous year.¹⁵¹ This estimate is not directly comparable to the narrower 53.2 GtCO₂e figure above, which excludes land-use change and uses a different sectoral boundary. The world is on track for 2.3–2.5°C temperature increase by 2100 under full nationally determined contributions (NDCs)¹⁵² and 2.8°C under current policies, which is a more credible forecast. However, 2025 marked a historic exception: China's CO₂ fell 0.3%—the first clean energy-driven decline.

In 2025, global energy-related CO₂ emissions hit a new high of 38.4 GtCO₂, up 0.4% as the slowdown in China was offset by gas-to-coal switching in the U.S.¹⁵³



¹⁵¹Climate TRACE, "Global Greenhouse Gas Emissions Hit a New Record High in 2025," 26 February 2026: full-year 2025 GHG emissions of 60.63 GtCO₂e (+0.5%), based on a broader satellite-derived sectoral inventory than EDGAR's narrower estimate

¹⁵²NDC: Nationally Determined Contributions, which reflect optimistic political national objectives.

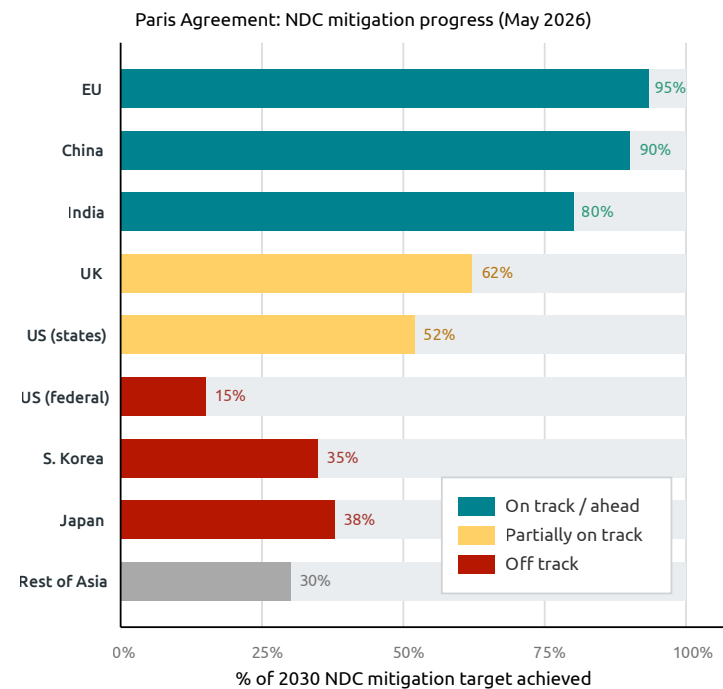
¹⁵³IEA, Global Energy Review 2026 — CO₂ Emissions, IEA, Paris (2026): energy-related CO₂ emissions reached 38.4 GtCO₂ in 2025, up 0.4% — the slowest growth rate since 2021.

The figure below shows each region's progress against its Paris Agreement commitment; even the most advanced are unlikely to fully reach their targets.

Figure 16

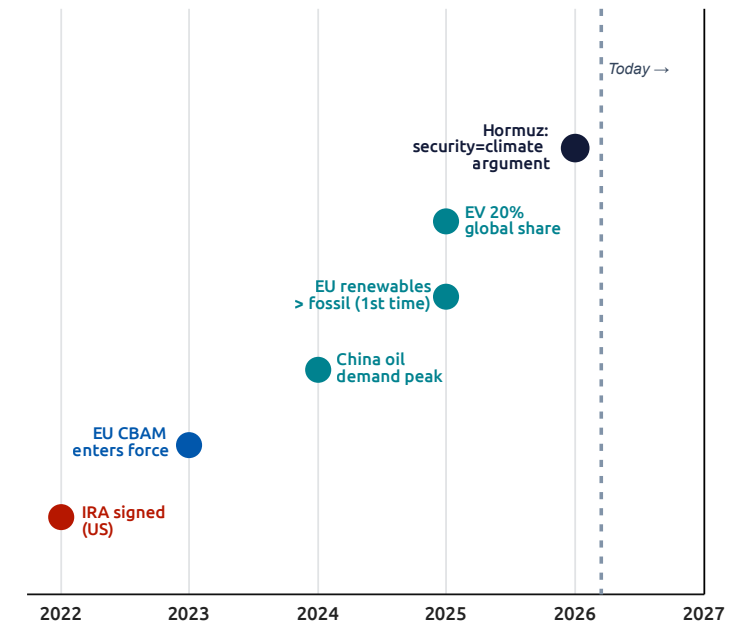
NDC mitigation progress vs Paris Agreement targets (May 2026). EU, China, and India on track; U.K. and U.S. states partially on track; U.S. federal, South Korea, Japan, and the rest of Asia falling behind.

EU & China on track; US, Japan, S. Korea face significant gaps



Key inflection events 2022–2026

The case for emissions decrease has never been stronger



Sources: Climate Action Tracker / NewClimate Institute, November 2025.¹⁵⁴

¹⁵⁴Climate Action Tracker / NewClimate Institute, November 2025.



7.2 New climate science: The CMIP7 scenario update

In April 2026, the climate science methodology was significantly updated. The seventh generation of climate models used by the Intergovernmental Panel on Climate Change (IPCC)—the Coupled Model Intercomparison Project, Phase 7 (CMIP7¹⁵⁵)—redraws the boundaries of credible warming trajectories, with direct implications for energy policy.

The most extreme scenarios have been retired

The outgoing CMIP6 framework included a “worst case” pathway, projecting +4.4°C by 2100 under unrestrained fossil fuel combustion. CMIP7 has retired this scenario as no longer plausible in that the “business as usual” trajectory it assumed has been improved by actual renewables deployment, efficiency gains, and policy changes since 2015. Lead author Detlef Van Vuuren called these former projections “simply false” as a description of where the world is heading.¹⁵⁶

Similarly, the most optimistic CMIP6 pathway—limiting warming to 1.5°C by 2100—has been dropped, as exceeding 1.5°C is now considered almost inevitable even under the most ambitious climate policies currently in place.

The new central range: +1.7°C to +3.5°C

CMIP7 establishes five new pathways. The central range spans +1.7°C (more ambitious than full NDC implementation) to +3.5°C (current policies, no further ambition). The “current trajectory” scenario, which reflects actual 2026 policies, points to median warming of approximately +2.7°C by 2100.¹⁵⁷ The most ambitious scenario, +1.7°C, requires policy acceleration well beyond current NDCs.

What remains uncertain

Narrowing the scenario range does not resolve the deepest uncertainties. CMIP7 scientists flag natural carbon sinks, including forests, oceans, and permafrost, as the largest source of model divergence. Permafrost feedback loops could add +0.3 to +0.6°C if triggered at scale; ocean heat content set new records again in 2025–2026; and several models project that the Atlantic Meridional Overturning Circulation (AMOC)¹⁵⁸ could weaken materially, with large consequences for Northern Europe. Several more years of real-world data are needed to resolve the full uncertainty range.

In summary, CMIP7 paints a more constrained picture: the most extreme warming scenario (+4.4°C) is no longer considered credible, while the most optimistic outcome—limiting warming to 1.5°C—is now effectively out of reach. Every investment in clean energy, grid resilience, and adaptation today ensures against that upper end, which is highly damaging.

¹⁵⁵Coupled Model Intercomparison Project, Phase 7. It is the international framework coordinating climate-model experiments; CMIP7 is the current generation, following CMIP6/CMIP5.

¹⁵⁶Detlef Van Vuuren, Utrecht University; lead author, CMIP7 Scenario MIP (April 2026).

¹⁵⁷Climate Action Tracker / New Climate Institute, November 2025 assessment of warming under current policies.

¹⁵⁸The Atlantic Meridional Overturning Circulation is the system of ocean currents that moves water through the Atlantic — most famously including the Gulf Stream — and it's one of the major heat-redistribution engines of the planet's climate.

¹⁵⁹Environmental, Social, and Governance is a framework used by investors, companies, and regulators to assess a company's practices and risks beyond pure financial performance.

¹⁶⁰White House executive orders on climate-related financial risk (2025); Net-Zero Banking Alliance membership disclosures, 2025; SEC climate disclosure rule litigation status, 2024–2026; Reuters/Bloomberg ESG-retreat coverage, 2025–2026.

¹⁶¹European Commission, Corporate Sustainability Reporting Directive (2022/2464) and European Sustainability Reporting Standards; EU Carbon Border Adjustment Mechanism Regulation (2023/956); EU Taxonomy Regulation (2020/852); Sustainable Finance Disclosure Regulation (2019/2088).

7.3 Environmental, social and governance (ESG) obligations for private companies: A structural divergence between the U.S. and Europe

In 2025, the Trump administration's “Big Beautiful Bill” crystallized a structural divergence: the U.S. and Europe now operate in fundamentally different environmental, social, and governance (ESG)¹⁵⁹ regimes. Trump-administration executive orders have eliminated federal climate risk requirements.

On the companies' side J.P. Morgan, Goldman Sachs, Wells Fargo, and Citigroup withdrew from the Net-Zero Banking Alliance, while BlackRock and State Street have retreated from shareholder climate activism.¹⁶⁰

Europe has embedded ESG into mandatory regulation insulated from electoral reversal. The Corporate Sustainability Reporting Directive (CSRD) (FY2025) mandates climate, biodiversity, and governance disclosures, while the Carbon Border Adjustment Mechanism (CBAM) imposes carbon costs on steel, cement, aluminum, fertilizer, electricity, and hydrogen imports from 2026. The EU Taxonomy, which determines green-bond and state-aid eligibility, cannot easily be dismantled by a change of Commission.¹⁶¹

The Hormuz crisis has, paradoxically, both reinforced European ESG momentum and created new tensions. The energy sovereignty argument gives clean energy a national security framing; however, the crisis has also rehabilitated gas as a “transition fuel” which has no scientific ground.¹⁶² Eastern European pressure on gas has increasingly focused on resisting sanctions on Russian gas supply. Hungary and Slovakia, the EU's most Russia-dependent gas and oil importers, have repeatedly blocked EU sanctions packages since

¹⁶²Natural gas is methane (CH₄) is a potent greenhouse gas and is the second-largest contributor to Earth's warming after carbon dioxide (CO₂). <https://science.nasa.gov/earth/explore/earth-indicators/methane/>

¹⁶³Euronews, “Hungary and Slovakia under pressure as US and EU target Russia with energy sanctions” (11 Sept. 2025); Balkan Insight, “Playing for Time: Pressure Mounts on Hungary, Slovakia to Cut Russian Energy Ties” (24 Sept. 2025).

¹⁶⁴EU Perspectives, “Slovakia Fills Hungary's Veto Vacuum to Stall EU Sanctions on Russia” (April 2026); S&P Global, “EU finalizes ban on Russian gas, LNG by 2027” (26 Jan. 2026).

2025, citing energy security.¹⁶³ Both governments have vowed to challenge the EU's 2027 Russian gas ban at the European Court of Justice.¹⁶⁴ This would build on the EU's 2022 taxonomy act, which already labels qualifying gas plants sustainable until 2030.

As a summary: ESG is not dead but bifurcating: In the United States, the focus is shifting toward narrower, state-led disclosure requirements. In Europe, ESG is becoming a mandatory compliance framework, reinforced by the growing importance of energy security. Companies in the U.S. and European markets face genuinely incompatible requirements.

7.4 The adaptation imperative

With warming of 2.3–2.5°C projected even under the full implementation of countries' commitments, adaptation is now as urgent as mitigation.

International public adaptation finance reached just \$26 billion in 2023, down from \$28 billion in 2022, while the United Nations Environment Programme (UNEP) puts developing country adaptation needs at \$310–365 billion annually by 2035—a gap of \$284–339 billion per year, or 12–14 times current flows.¹⁶⁵ The private sector contributes only around \$5 billion annually today against an estimated \$50 billion annual potential if backed by policy support.¹⁶⁶ As a result, the Glasgow Climate Pact goal of doubling 2019 finance to ~\$40 billion per year by 2025 is already missed.¹⁶⁷

Adaptation is increasingly also an insurance market problem. Global economic losses from natural catastrophes reached \$220 billion in

2025, of which insurers covered a record \$107 billion (49%)—the highest insured share on record.¹⁶⁸ Yet 80–90% of catastrophe losses in emerging economies remain uninsured.¹⁶⁹ The January 2025 Los Angeles wildfires alone generated \$40 billion in insured losses, a record for a wildfire catastrophe.¹⁷⁰ Swiss Re projects insured losses could reach \$186 billion annually by 2030 based on current trends¹⁷¹ underscoring the idea that reducing physical exposure through adaptation is now as much a balance sheet imperative for insurers as a humanitarian one.

Leading adaptation initiatives include: The Netherlands' Room for the River (30 river restoration projects; 10,000 residents relocated from high-risk flood zones); France's National Heat Action Plan (an estimated 14,800 heat-related deaths prevented since 2003); Morocco's Al Maouj Plan (€2.5 billion investment; 1 million hectares of drought-resistant crops); and Florida's SB 948 (2025) (mandatory flood-risk disclosure for all property transactions).¹⁷²

Conclusion:

Adaptation planning is advancing with 172 of 197 United Nation countries now having a national adaptation plan. However, the funding and insurance protection gaps are both widening. Regulation must make adaptation and risk disclosure mandatory and carbon pricing revenue should be earmarked for resilience investment.



¹⁶⁵UNEP, Adaptation Gap Report 2025: Running on Empty, 29 October 2025.

¹⁶⁶UNEP, Adaptation Gap Report 2025: Running on Empty, 29 October 2025 — private-sector adaptation finance estimated at ~\$5bn/yr currently, versus ~\$50bn/yr potential if backed by targeted policy action and blended finance solutions.

¹⁶⁷UNEP, Adaptation Gap Report 2025: Running on Empty, 29 October 2025; UNFCCC, Doubling Adaptation Finance: Efforts to Respond to the Call of the Glasgow Climate Pact. Adaptation finance grew at a 7% compound annual rate over 2019–23, short of the 12% pace needed to double 2019 flows (~\$20bn) to ~\$40bn/yr by 2025; further aid-budget cuts announced in 2025 make the miss more likely.

¹⁶⁸Swiss Re Institute, sigma 1/2026: Natural Catastrophes in 2025 — The Persistent Rise of Wildfire and Storm Risk, 19 March 2026 — global economic losses of \$220bn in 2025, with insurers covering a record 49% (\$107bn), the highest insured share on sigma record.

¹⁶⁹Swiss Re Institute, sigma 1/2026 (as above); Swiss Re Institute, "Adaptation and insurance: strategies to narrow the protection gap" — protection gaps remain widest in emerging economies, where 80–90% of catastrophe losses are typically uninsured; the Myanmar earthquake (March 2025, ~\$11bn in economic losses) generated insured losses of just over \$200m.

¹⁷⁰Munich Re, loss estimate for the January 2025 Palisades and Eaton fires — approximately \$40bn in insured losses against ~\$53bn in total economic losses, the largest insured loss on record from a wildfire event; corroborated by Howden Re, which ranked the event 2025's costliest catastrophe.

¹⁷¹Swiss Re Institute, sigma 1/2026: Natural Catastrophes in 2025 — The Persistent Rise of Wildfire and Storm Risk, 19 March 2026.

¹⁷²Florida Senate Bill 948 (2025), mandatory flood-risk disclosure in residential real-estate transactions.



08

Conclusion





This 2026 Outlook has tracked how the Hormuz shock, the acceleration of electrification, and the rise of AI-driven electricity demand are reshaping global energy markets. Six conclusions stand out.

1. Energy sovereignty is being redefined

In just a few years, the world has moved from an era of expanding free trade and globalization to one where sovereignty is actively promoted across many regions, including the United States and Europe and its member states. The COVID crisis was a turning point: logistics disruptions pushed companies to shorten or localize supply chains. The war in Ukraine then made Europe—and Germany above all—aware of its dependence on Russian gas, prompting embargoes designed to restrict the financial resources fueling Russia's war effort. The trade war with China, which built enormous surplus capacity across clean energy hardware, notably solar PV and onshore wind, allowed the nation to export equipment at very low prices, which triggered factory closures in Europe and elsewhere. The Trump administration's reversal of U.S. energy policy toward domestically produced fossil fuels is, in its own way, also an act of sovereignty; however, per this report's own framework, it satisfies the sovereignty criterion while failing the clean criteria simultaneously required for a durable energy strategy.

In the Middle East, shipping lanes for LNG and oil tankers have been disrupted by conflicts: Houthi attacks first made the route toward the Suez Canal riskier, forcing vessels around the Cape of Good Hope; more recently, Iran's closure of the Strait of Hormuz made many regions of the world—and Asia in particular—aware of their dependence on Middle Eastern oil and gas, reinforcing the drive for energy sovereignty.

Globalization benefited consumers by making low-cost products available, and it also fueled the growth of solar power built on Chinese-made panels. But it has been less kind to European industry,

where many factories have closed and the region has lost ground in critical minerals and battery manufacturing. Sweden's Northvolt, once the sector's flagship, filed for bankruptcy in November 2024 and again in March 2025, while several other European battery gigafactory projects have stalled or fallen behind schedule. Europe has lost not only industrial output in these areas but also industrial know-how.

The world cannot return to a closed model that would deprive consumers of Chinese products and innovation; sovereignty must therefore be pursued with balance, through mixed solutions such as partnerships with Chinese players to localize the manufacturing of solar panels, wind turbines and batteries, along with their associated supply chains. Given the challenges facing Europe's battery gigafactory sector, such partnerships are already taking shape. Examples include Envision-owned AESC ramping up production at its Douai plant to supply Renault, and the Orano-XTC New Energy joint venture developing a cathode active material plant in Dunkirk under the Choose France initiative.

2. Electrification is accelerating, but the most extreme data center forecasts are unlikely to materialize in full

Faced with the Strait of Hormuz crisis, many governments in Europe and Asia, in particular, decided to accelerate the electrification of end uses. This is an excellent direction, provided the additional electricity is not generated from fossil fuels. After roughly 15 years of stagnation in Europe, the growth of electric vehicles, heat pumps, and data centers should push electricity consumption higher.

Electricity consumption projections tied to data centers in countries such as the United States are skyrocketing and highly concentrated geographically. Grid connection is an important brake on this growth, and hyperscalers are increasingly turning to off-grid

solutions, including: gas turbines in the United States, which are quick to deploy but emit significant greenhouse gases, and combined solar, wind, and battery industrial parks such as those in China's Gobi Desert, which are cleaner but require vast amounts of land.

These electricity-supply constraints, combined with open questions over AI's economic returns, chip availability, and the development of specialized, less energy-intensive models as a partial substitute for large language models, are reflected in projected data center completion rates that vary widely by region: approximately 20% in the United States, 30–40% in Europe, and 65–75% in China. It is therefore likely that the most ambitious scenarios for electricity-demand growth will not materialize in full. Nonetheless, the growth that does occur in data centers, combined with intermittent renewables, is already placing significant strain on how electricity grids operate.

3. Nuclear, hydropower, and geothermal remain the only sovereign, dispatchable, zero-emission power sources

Nuclear power, hydropower and geothermal energy are the only forms of electricity generation that are simultaneously sovereign, free of greenhouse gas emissions and dispatchable, allowing them to balance grids under growing strain. Nuclear reactor lifetime extensions now underway in many countries make it possible to produce decarbonized, dispatchable electricity competitively; existing reactors should no longer be shut down for political reasons, as happened in the past.

The political will to build new nuclear reactors is real on almost every continent: 74 reactors totaling 66 GW, are under construction, 37 of which are in China. This renaissance will combine large





reactors of roughly 1,000 MW with, most likely, small modular reactors of around 300 MW, generally built in multi-module configurations.

Building large reactors remains a very difficult undertaking given their scale, complexity, and safety requirements. Project management must improve in Western countries for the electricity produced to be competitive. This requires rebuilding skills, revitalizing the sector's supply chain, easing regulatory constraints, and securing financing at competitive rates. The serial-build effect, as practiced in China and, historically in France with its 900 MW fleet, would also cut construction time and cost. This is the logic behind France's plan to launch a series of six EPR2 reactors. China, which today builds more than half of the world's new reactors, appears to have mastered both construction timelines and costs.

Numerous SMR projects are underway worldwide, based either on scaled-down large-reactor technology or on more advanced modular reactor designs. Their competitive edge is meant to come from come from serial manufacturing, something no Western country has yet achieved. Canada's BWRX-300 could become the first Western SMR in operation, targeted for 2030. Given this immaturity, it is not yet possible to reliably assess the cost of electricity to be produced by Western SMRs. China and Russia, by contrast, already have SMRs in operation, with Rosatom running the most advanced program: the serial construction of the RITM-200N, derived from icebreaker reactor technology.

4. The grid is the backbone of the energy transition, and it needs both investment and reform

The electricity grid is the backbone of the energy transformation. Balancing is becoming more complex as intermittent generation grows

and new, geographically concentrated demand—including from data centers,—emerges. Grid flexibility must be strengthened.

Thanks to a spectacular decline in costs, massive investment is flowing into stationary battery farms, or BESS, which increase the grid's storage capacity and therefore its flexibility. By 2030, stationary battery storage in Europe is expected to surpass pumped hydro in installed capacity. However, the two technologies serve different roles: batteries typically discharge over hours, while pumped hydro can sustain output for months. Other forms of flexibility, such as better matching of demand to supply through demand-side response, aggregators and virtual power plants, must be scaled up faster, backed by proactive regulation. Finally, regulatory reform is needed to unlock physical investment in new lines, interconnections in particular, as well as in sensors and digital tools, including artificial intelligence. Connection rules for renewables and data centers must also change: grid connection wait times in the West now stretch to several years, including around five years in the United States, imposing a major brake on bringing these projects into service.

5. Continuous technology improvement remains the transition's most reliable engine, with AI as a short-term frontier and fusion as a long-term one

Continuous improvements in the design and production of photovoltaic cells, wind turbines and batteries, combined with proactive policy support, have driven spectacular cost declines, a trend not yet matched by electrolyzers. Sustaining this trajectory will require even greater investment in research, development and industrialization. Beyond scientific expertise, which remains essential, bringing new technologies to market faster depends on funding for laboratories and start-ups and on investors' appetite for risk.

As in many other sectors, the United States and China currently lead the race.

Nuclear fusion remains experimental. Despite real progress over the past year, break-even has not been achieved in any laboratory and commercially viable fusion before 2040, or even 2050, is considered unlikely by most plasma physicists. Electricity production from fusion therefore remains distant, and the survival of many active fusion start-ups is uncertain.

The use of artificial intelligence, which utilities are beginning to adopt, is already delivering progress, notably in grid balancing operations. Looking ahead, physical AI combined with robotics should further improve the operation and maintenance of power plants and electricity grids.

6. It is unlikely that the climate goals will be met, and adaptation measures can no longer wait

Short of a severe crisis, pandemic or a generalized war, none of which anyone should wish for, it is increasingly unlikely that the Paris Agreement's targets will be met. Adaptation measures for the infrastructure most essential to withstanding climate change must therefore be put in place without delay.

The following chapter translates these conclusions into seven concrete recommendations for governments and energy companies.





09

Recommendations





Recommendations for energy companies and governments

1. Adopt a pragmatic, long-term approach to energy sovereignty

After decades of trade liberalization and technological globalization, the world cannot return to a closed model that would deprive consumers of low labor cost countries' products and Chinese innovations. Sovereignty must therefore be pursued with appropriate balance, through mixed solutions such as partnerships with non-national players (for example Chinese players) to localize the manufacturing of clean-technology equipment and its associated supply chains.

2. Accelerate the electrification of buildings and transport

Heat pumps, EVs, and industrial electrification remain the correct strategic response to fossil dependency. Governments and industry should resist the temptation created by the post Hormuz likely oil and gas prices declines—the next shock could come sooner than expected—and pursue with determination the electrification plans already launched across many regions.

3. Accelerate grid investment and regulatory reform, and scale up AI deployment

The grid, not generation technology, is the energy transition's critical bottleneck. Public and private financing should be mobilized, and regulation streamlined, to lift grid investment above \$500 billion annually by 2030, spanning both hardware and software.

Priority should go to clearing the multi-year connection queues in Europe and the U.S.—the latter exceeding 2,000 GW and averaging more than five years—which are holding back both renewable and data-center deployment.

Because physical grid construction is slow and capital intensive, digital optimization of grid operations is essential to keep the clean energy transition on track. Wider deployment of GETs and of AI should therefore be accelerated.

4. Strengthen grid flexibility

As intermittent renewable generation grows, so does the strain on grid stability—and with it the need for flexibility. For example, in Europe intermittent renewable generation is expected to roughly double between 2025 and 2033. The fastest and cheapest gains lie in demand-side flexibility, including demand response, aggregators, and virtual power plants, as well as in storage, where battery costs continue to fall sharply. Governments should set incentives and binding targets to scale both.

5. Deploy dispatchable clean power generation alongside renewables

Nuclear lifetimes should be extended to 60–80 years wherever safety allows, and safe plants should not be closed for political reasons.

New nuclear and hydro capacity (where geographically possible) should be built, since intermittent renewables alone cannot guarantee grid stability. Delivering a genuine nuclear renaissance requires Western countries to rebuild technical and project-management skills, streamline regulation, revitalize the supply chain, and facilitate financing so that new reactors can be built on time and on budget.

6. Continue to push technology improvement and step up AI adoption

There are no “silver bullets” in energy technology. Governments and companies should increase investment in research and development and ease the financing of clean technology industrialization to sustain continuous improvement. The United States and China currently lead this race, and Europe must catch up.

The wide-scale adoption of generative and physical AI should be a game changer for generation, grid operations, and customers' contribution to demand flexibility.

7. Address the adaptation imperative

The current-trajectory scenario—reflecting actual 2026 policies—points to median warming of approximately +2.7°C by 2100. Adaptation is no longer a fallback option; it is now an urgent imperative running in parallel with mitigation. Regulation should make adaptation measures mandatory, while international adaptation financing should be scaled up from \$26 billion per year toward the \$310–365 billion annually required by 2035. Mandatory climate-risk disclosure, as introduced in Florida's SB 948, is a scalable model.



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