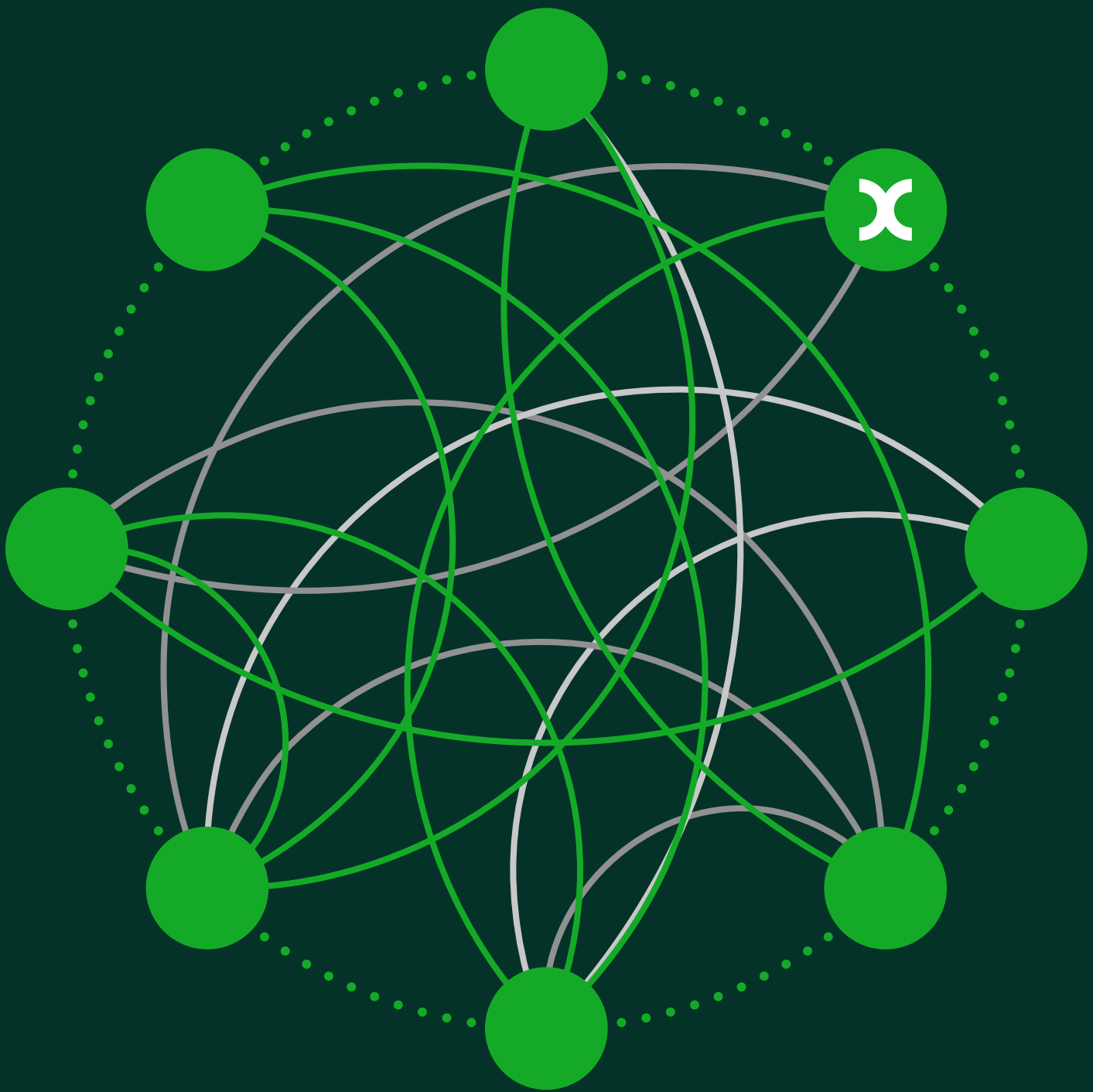
Financing nuclear: from policy ambition to investable programmes

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9 November 2026



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1 Introduction

Nuclear power has returned to the centre of energy policy. Electricity demand is rising because of electrification, data centres, artificial intelligence and industrial expansion; governments are attaching greater value to firm-generating capacity that is also domestic; and volatile fossil-fuel markets have reinforced the coupling of energy, geopolitics and national security. The result has been a proliferation of nuclear capacity expansion targets, life-extension programmes, small modular reactor projects and—in a separate and more nascent technology category—fusion development initiatives.

Nevertheless, policy intent on its own does not lead to a financeable construction pipeline. The decisive variables are standardisation, appropriate risk allocation, regulatory credibility and confidence in programme delivery. The investment gap that needs to be closed is immense.

Four key themes currently of pressing interest to the nuclear power community are discussed and structured as follows.

- The strategic outlook for nuclear power (section 2).
- The scale and timing of the nuclear investment opportunity (section 3).
- Principal barriers to investment (section 4).
- Nuclear technologies' financing challenges (section 5).
- Scaling up from plants to investable programmes (section 6).
- Concluding remarks (section 7).

A glossary of nuclear terminology is provided at the end of the document.

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2 Strategic outlook

Nuclear technologies face three strategic challenges.

First, **long construction periods, combined with a material risk of construction overruns, slow the rate at which experience and learning-by-doing feed into subsequent projects**. The stop–start nature of new-build programmes, bespoke designs and regulatory changes can therefore produce flat learning curves. Even adverse learning curves are possible, particularly if there has been an extended investment hiatus. China and South Korea demonstrate that repeat construction of standardised designs can improve performance, but this is a programme-level outcome.

Second, **complex licensing, permitting and government-support negotiations materially increase development costs**. This is especially serious in countries with limited regulatory experience and capacity, utilities with constrained balance sheets, and uncertain regulatory arrangements for liability, decommissioning and waste. Even a technically competitive reactor can become uneconomic if investors must carry several years of unremunerated development expenditure and open-ended construction risk.

Third, **the eventual share of nuclear in the energy mix remains uncertain in many markets**. Cost reductions in renewables, long-duration storage, carbon capture and interconnection, together with greater demand flexibility, could all reduce the nuclear capacity required after 2050. A nuclear investment case and government support packages therefore need to be evaluated against future power system performance and costs, rather than comparing reactor-level generation costs with solar, wind, or abated fossil projects.

These challenges derive from the high level of construction risks seen today as well as the lack of international harmonisation in licensing, permitting and government support package design. Ultimately, this leads to challenges at the programme level that threaten to limit long-term expansion of nuclear capacity.

The counterpoint is that nuclear complements renewables. Nuclear plants provide baseload low-carbon electricity that offsets lower output from weather-dependent generators. Modular reactors with improved load-following capability, paired with storage, could increase their contribution to system performance and value. Advanced designs

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supplying high-temperature heat could decarbonise steel, chemicals and mining, in part by enabling more efficient hydrogen production.

Meanwhile, the 2026 Iran–US conflict and the disruption of shipping through the Strait of Hormuz have strengthened the security argument for nuclear capacity. Nuclear fuel can be stockpiled for years and represents a small share of generation costs, leaving nuclear far less exposed than gas-fired generation to disrupted deliveries and commodity price volatility. **Volatile geopolitics reinforce the long-term case for diversifying the capacity mix across nuclear, renewables, storage, grids and demand-side flexibility**.[1] As in past crises, however, this recent episode has raised price volatility and macroeconomic uncertainty, and higher financing costs disproportionately damage capital-intensive projects with extended development and construction lead times.

[1] International Energy Agency (2006), 'Impacts of Middle East conflict set to reshape energy investment plans as disruptions put focus on security', 28 May (last accessed 20 August 2026).

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3 Scale and timing of the nuclear investment opportunity

The World Nuclear Association's (WNA) recent Nuclear Investment Guide models an expansion from roughly 400GW of installed nuclear capacity today to around 1,440GW in 2050 if stated government ambitions are achieved.[2] The scenario implies an expansion of approximately 1,040GW roughly split between 780GW of large reactors and 260GW of small modular reactors (SMRs).[3] As recently as 2021, the International Energy Agency (IEA) projected the annual rate of nuclear capacity additions to be close to half the level projected by the WNA.[4] Also, the International Atomic Energy Agency's (IAEA) 2025 'high case' for nuclear expansion is for approximately 990GW of operational capacity available by 2050.[5] The WNA's scenario thereby provides a strong indication of the increased ambition of the nuclear sector as a whole.

However, greater ambition for more nuclear capacity also connects with the financing challenge. For example, the WNA's overnight investment cost estimate is close to $5.8trn (2025 prices), roughly comprising:[6]

- $3.5trn for large reactors, $1.5trn for SMRs and $220bn for life extensions;
- $240bn for mining, conversion, enrichment and fuel fabrication;
- $320bn for decommissioning and interim waste storage.

Importantly, these figures exclude financing costs, transmission investment and an estimated $510bn for geological disposal. The WNA assumes construction lead times of five (Asia) to seven (non-Asia) years, strong learning rates, and successful global SMR deployment. These assumptions are consistent with the 'high ambition' global expansion scenario discussed above, not a forecast of committed projects.

[2] 'GW' refers to gross electrical output unless otherwise specified.
[3] World Nuclear Association (2026), 'A $6 Trillion Investment Opportunity: Nuclear value chain investment through 2050', 30 July, p. v (last accessed 19 August 2026).
[4] International Energy Agency (2021), 'Net Zero by 2050: A Roadmap for the Global Energy Sector', 18 May, p. 117 (last accessed 15 August 2026).
[5] International Atomic Energy Agency (2025), 'Energy, Electricity and Nuclear Power Estimates for the Period up to 2050', September, p. 1 (last accessed 20 August 2026).
[6] World Nuclear Association (2026), 'A $6 Trillion Investment Opportunity: Nuclear value chain investment through 2050', 30 July, p. iv (last accessed 19 August 2026).

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The implication of the WNA's scenario is that annual nuclear investment would need to increase to roughly $250bn per year, on average, over 2026–50. The IEA has estimated that nuclear investment in 2025 was in the region of $80bn, indicating that the financing challenge is substantial.[7]

Regional ambitions and policy direction

In addition to considering the capacity and capital aggregates in the WNA's nuclear expansion scenario, realising nuclear capacity growth depends crucially on government intentions and policies in key regions as well as their regulatory and market readiness.

Table 3.1 below provides an overview of approximate current and prospective nuclear capacity by country and region based on available national commitments.

Table 3.1 Current and projected nuclear capacity by country and region

Region, country	Approximate current position and stated ambition to 2050	Comment
USA	From 103GW today to 400GW by 2050.	Formal federal objective; roughly 300GW growth, but far beyond the present committed pipeline.
China	From 69GW today to 95.4GW by 2030; 335GW institutional projection for 2050.	Largest and most credible programme, although 335GW is not equivalent to a fully approved project schedule.
India	From 8.8GW today to 100GW by 2047.	Transformational target: 22GW expected by 2031–32, while much of the post-2032 programme remains to be contracted.

[7] International Energy Agency (2026), 'World Energy Investment 2026', 28 May, p. 8 (last accessed 20 August 2026).

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Region, country	Approximate current position and stated ambition to 2050	Comment
Europe	From 98GW in 2025 to 109GW (central case) or up to 140GW (high case) institutional projection in 2050.	Moderate net growth conceals extensive retirement, life-extension and replacement investment. Non-EU member states add no material quantified target.
Japan	33GW currently classed as operable; indicative 37GW in 2050.	Policy centres on restarts, extensions and replacements rather than large net growth.
ASEAN	No current operating plants; indicative national plans sum to around 40GW by 2050.	Not an ASEAN-wide target; Indonesia, Vietnam and the Philippines dominate the total.
GCC	UAE currently has about 5.4GW; Saudi Arabia has cited 17GW by 2040.	Upper-bound pathway exceeds 22GW, but a more concrete Saudi first phase is about 2.8GW.
Africa	1.9GW operating, plus Egypt under construction; IAEA high case implies roughly 18–20GW by 2050.	Indicative scenario rather than continental commitment; institutional and financing constraints are decisive.

Sources: U.S. Department of Energy (2026), 'The Energy Department Is Delivering On Accelerating The Deployment Of Nuclear Power', 19 January (last accessed 24 August 2026); Nuclear Regulatory Commission (2025), 'Ordering the reform of the Nuclear Regulatory Commission: Executive Order 14300', 23 May (last accessed 24 August 2026); World Nuclear Association (2026), 'China - World Nuclear Outlook Report', 16 October (last accessed 3 November 2026); Department of Atomic Energy (2026),'Parliament question: nuclear energy mission for Viksit Bharat', 22 July (last accessed 23 August 2026); ASEAN Centre for Energy (2026), 'ASEAN Energy in 2026', 3 February (last accessed 23 August 2026); World Bank (2025), 'World Bank Group, IAEA Formalize Partnership to Collaborate on Nuclear Energy for Development', 26 June (last accessed 23 August 2026); International Atomic Energy Agency (2026), 'Nuclear Power in Africa: Opportunities for the Future', 15 May (last accessed 23 August 2026); Emirates Nuclear Energy Company (2025), 'ENEC and GE Vernova Hitachi sign Small Modular Reactor deployment evaluation MoU during World Utilities Congress', 27 May (last accessed 23 August 2026); World Nuclear Association (2026), 'Nuclear Power in Saudi Arabia', 24 July (last accessed 23 August 2026); METI (2026), 'A Detailed Outline of the Latest Strategic Energy Plan—Insights into Japan's Energy in a Drastically Changing World', 26 May (last accessed 22 August 2026); and European Commission (2026), 'Nuclear Illustrative Programme', 10 March (last accessed 29 August 2026).

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4 Principal barriers to investment

The preceding sections describe an ambition gap: roughly $250bn of annual investment needed over the coming decades against the $80bn delivered in 2025. Closing it requires an answer to why private capital does not flow easily to nuclear, because the design of appropriate instruments depends on which blockers are binding.

A market failure exists where the private valuation of a risk diverges from its social cost, or where a mutually beneficial transaction fails to complete despite both parties wanting it. This arises in at least three ways: risk cannot be allocated to whoever can bear it at the lowest cost; the price of risk embeds something other than the risk itself; or the value created by the investment is not captured by the investor bearing the risk. Applying this test avoids two recurring errors: (i) subsidising risks the market already prices correctly; and (ii) using public funds to offset distortions created by other policy interventions.

Externalities and missing system value

The foundational market failure is that the principal benefits of nuclear either are not fully remunerated or they instead accrue to market participants.

First, **CO_2 emissions are often incorrectly priced** in two ways: carbon taxes and cap-and-trade emission allowance prices are generally below damages-based estimates of the social cost of carbon, so avoided emissions are only partly monetised.[8] Also, traded emission prices are more volatile than necessary, further weakening the long-horizon investment incentive for emission-reduction projects.[9]

Second, **nuclear's contribution to security of supply and system resilience is typically not fully captured by investors** because these are properties of the system as a whole, thereby leading to free-riding and

[8] In August 2026, the European Union Allowance (EUA)—the carbon emission permit in the EU Emissions Trading System—traded in the region of €80–90 per tCO_2, whereas the social cost of carbon (SCC) derived from long-term climate simulations is frequently over twice as high.
[9] Benmir, G. et al. (2026), 'Weitzman Meets Taylor: EU Allowance Price Drivers and Carbon Cap Rules', Grantham Research Institute working paper 421, 19 February, pp. 25, 34–36 (last accessed 24 August 2026).

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under-supply.[10] These are costs that nuclear can help avoid, and this implicit benefit instead accrues to taxpayers and consumers.

Government policies and market design can also penalise nuclear's output profile. As renewable penetration rises, wholesale prices are suppressed during many hours when baseload plants operate, eroding captured prices through 'cannibalisation'. Modelling by the GB system operator indicates SMR utilisation could fall to 55% under a high-renewables 2050 mix, potentially enough to render deployment uneconomic.[11] No instrument exists to hedge either the level or the hourly 'shape' of power prices over a 60-year horizon, and capacity markets clearing on one- to 15-year horizons cannot fill the gap.

Missing markets

Certain transactions do not occur at any price. Long-dated power purchasing agreements (PPAs) are absent because no private counterparty carries a credit rating credible over a 60-year asset life. Across EU, UK and US electricity markets, PPAs can have tenors up to 10–20 years, but only for the output from existing operating plants (including completed new-build and restarted plants). That said, AI 'hyperscaler' demand has reportedly extended achievable contract tenors in the USA and demonstrated willingness to pay a substantial premium over nuclear operating costs for firm 'low carbon' electricity.

Also, private insurance against construction overruns and persistent outages is not available because insurance requires a large pool of independent risks, whereas nuclear offers a handful of highly correlated mega-projects sharing common drivers. Severe-accident liability is capped by international convention precisely because private capacity for such losses does not exist. End-of-life obligations compound this: the $320bn decommissioning and $510bn disposal estimates cited earlier represent liabilities extending beyond any reasonable expectation of corporate lifespan.

Illiquidity and financing frictions

Equity and debt in nuclear project companies cannot readily be traded. A part-built reactor has almost no alternative-use value, so exit is

[10] This occurs when end-users cannot be excluded from appropriating these system benefits, and when their availability is not impacted by the number of end-users accessing them. These criteria define 'public goods'.
[11] National Energy System Operator (2023), 'Future Energy Scenarios: ESO pathways to net zero', July (last accessed 29 August 2026).

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impossible when risk peaks; lack of standardisation means every transaction demands bespoke diligence with no comparables; and the pool of potential buyers is thin because ownership is subject to regulatory qualification. National security screening can also constrain asset transfers, as in the case of the exit of China General Nuclear from Sizewell C (SZC) in 2022.[12]

Additional impediments are financial rather than economic or regulatory in origin. **Capital indivisibility means a single project exceeds the balance-sheet capacity of most private entities**—two large reactors at SZC are expected to cost in the region of £40bn, and financing is committed up to approximately £48bn (2024/25 prices).[13] A project capable of financially destroying its sponsor induces greater caution and conservatism. EDF's renationalisation in 2022 was in part motivated by the cost overruns from three challenging new-build projects (i.e. Olkiluoto 3, Hinkley Point C and Flamanville 3) representing around 9% of its operational fleet.[14]

Hold-up

Because nearly all nuclear capital is sunk at commissioning, the incentive to expropriate value is greatest when investors are most exposed. Given that investors price observed precedent, including retrospective tariff reductions in Spain and Italy, and Germany's abrupt 2011 nuclear phase-out, RAB models and contracts for difference (CfDs) do not eliminate this risk so much as convert construction and revenue risk into regulatory commitment risk.

If the binding constraints differ by technology, so must the remedies. Table 4.1 below summarises the principal risks, market failures and financing implications.

[12] Nuclear Engineering International (2022), 'UK confirms support for Sizewell C and buys out China's stake', 1 December (last accessed 29 August 2026).
[13] National Audit Office (2026), 'Sizewell C', 30 May, p. 4 (last accessed 27 August 2026).
[14] Gaster, R. (2025), 'Lessons from France's Nuclear Program', 2 September (last accessed 27 August 2026).

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Table 4.1 Principal risks, market failures and financing implications for nuclear technologies

Technology	Principal risks and market failures	Financing implications
Large reactors (Gen III/III+)	Technology is proven, but project scale makes schedule, interface and interest-during-construction risks potentially existential. Compounded by regulatory commitment risk over a 60-year horizon, sunk-cost exposure to policy reversal, and end-of-life liabilities extending beyond corporate lifespans. Revenue risk is moderated due to position in the electricity merit order. Market failures: capital indivisibility and financial distress costs; uninsurable construction risk; hold-up and risk of regulatory commitment.	Sovereign or state-linked ownership dominates, particularly in support schemes that limit revenues during construction. Revenue support and/or cost recovery, completion support, export credit, and long-term contracts with state or state-backed counterparties are usually necessary; commercial PPAs are too short-dated to substitute. Revenue model determines whether interest compounds through construction or is serviced as incurred—the decisive variable as rates rise. Standard fleets are materially more financeable than isolated bespoke projects.

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Technology	Principal risks and market failures	Financing implications
Small modular reactors (Gen III/III+)	Smaller units reduce single-project exposure but may not lower cost per kW. Factory economics require a committed multi-unit orderbook before learning is realised. Utilisation is first-order risk: capacity factors in the range of c.70–93% are plausible depending on market design, offtake agreements, and capacity mix (e.g. renewable energy sources); low-utilisation assets are disproportionately exposed to rising interest rates as they are also more capital intensive. Market failures: coordination failure (fleet-before-factory, wider supply chain); non-appropriable learning across a serial programme; missing/incomplete markets for hedges for the level and shape of power prices.	Early units require grants, guarantees, aggregated procurement and a credible volume commitment. Regulated frameworks are at least as valuable as for large reactors, because revenues decoupled from output accommodate flexible operation. Mature fleets might access ordinary infrastructure debt once standardisation creates comparables and a tradable asset class.

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Technology	Principal risks and market failures	Financing implications
Advanced modular reactors (Gen IV)	Incremental coolant, materials, fuel-cycle and licensing risks compared with SMRs. Sodium fires, molten-salt corrosion and chemistry, TRISO production, HALEU availability and high-temperature components require demonstration. Limited recent commercial licensing precedent in Western markets for non-light-water designs, and disposal routes for novel fuel forms are undefined. Thorium-232 must breed fissile uranium-233 and does not remove criticality, safeguards or fuel-cycle risk. Market failures: regulatory capacity constraints; access to essential infrastructure (HALEU enrichment and fabrication); missing markets for fuel and non-electric output.	Financing constraints sit upstream of financing: no instrument resolves an absent fuel supply chain, an undefined waste route or a regulator without relevant capability. Financing will remain strategic public or corporate capital until integrated demonstrations establish cost, maintainability and availability. Public provision of enabling infrastructure and regulatory capability is the binding intervention.

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Technology	Principal risks and market failures	Financing implications
Fusion	Combines unresolved plasma or target physics with tritium breeding, neutron-resistant materials, remote maintenance and whole-plant efficiency risks. Supply chains for high-temperature superconducting tape and tritium handling are immature. Offsetting this, the absence of criticality and a small radiological inventory imply materially lighter liability, waste and decommissioning burdens, and the UK has established a proportionate regulatory regime under the Energy Act 2023. Market failures: innovation market failure; non-appropriable research spillovers; extended development horizon beyond commercial investor tolerance.	Uncertainty precluding any priced risk transfer. Venture equity, strategic corporate investment, milestone grants and public facilities are appropriate today; investment-grade constraints do not bind because the capital is not project debt. Project finance and revenue support become rational only after integrated net-electricity and maintainability demonstrations. Applying a regulated asset base model at this stage would be a category error.

Source: Oxera analysis.

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5 Financing challenges

The key challenge to nuclear power is deployment of sunk capital amid deep uncertainty. **The construction phase is where market and regulatory failures concentrate because it typically combines maximum sunk cost exposure with no revenue, and the ability to recover any value from a part-built reactor is very limited**.

Other challenges apply at programme level: learning-by-doing spillovers require commitment to a sequence of multiple units, and fuel cycle and waste assets have a minimum efficient scale far greater than one project. Because these are programme-level considerations, support packages that are structured and agreed one project at a time may leave enabling infrastructure chronically underfunded.

Support package components

The market failures described above are not addressed by any single instrument. **Every major Western government support package concluded or notified to date includes at least one, or more likely a combination, of three distinct types of intervention, each targeting a different market failure**.

The first is **risk transfer** in the form of long-term revenue support that limits or removes exposure to merchant risks (i.e. price capture and utilisation); financial risk transfers such as loan guarantees and construction cost-sharing; and regulatory commitments that secure access to waste, fuel and other essential infrastructure at cost-reflective prices. The second is **direct government financial participation** either through equity, subsidised debt, or both that addresses capital indivisibility and the duration constraints that limit private capital participation (especially due to long construction lead times). The third is an investable **regulatory regime** that includes change-of-law protection, transparent price-setting methodologies and stable regulatory institutions. These address the commitment problem rather than the risk itself.

Two ends of a spectrum: Hinkley Point C and Sizewell C

These two UK nuclear precedents arguably bracket the range of feasible risk allocations for the generation of nuclear technologies currently being contemplated in the EU and UK. An important qualification applies to the discussion below since every completed

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precedent so far relates to large reactors. Several SMR projects are now approaching financing, and a small number of advanced modular reactors (AMRs) are approaching deployment readiness, but the risk-allocation frameworks that will apply to them are not yet settled.[15] Extrapolating from large-reactor precedent to modular technologies should therefore be done with caution since the market failures differ as described in the previous section.

Hinkley Point C (HPC) represents the market-aligned end. A 35-year two-way CfD[16] was awarded in 2017 at a post-tax nominal Weighted Average Cost of Capital (WACC) of 9.2% (post-tax, nominal), producing a strike price of £92.5/MWh (2012 prices; approximately £129/MWh in 2024 prices).[17] Critically, revenue support is payable only after commissioning, so the developer finances construction through conventional project and corporate finance, absorbing all construction, regulatory and licensing risk with interest compounding across the construction period. HPC reached FID in July 2016 with an estimated construction cost of £18bn (2016 prices; approximately £24bn in 2024 prices). The project company was initially owned by EDF (66.5%) and China General Nuclear (CGN; 33.5%), but the UK government did not take an equity stake.[18] It was financed in full by its two shareholders from their own balance sheets with no third-party project debt.

SZC represents the regulated end. Under the RAB model, allowed revenues are set by reference to the value of the RAB from the start of construction and an 'initial WACC' reflecting the returns on debt and equity resulting from negotiations between prospective investors, the UK government, and their advisors. Before commissioning, consumers pay levies through their electricity bills that service debt interest as it accrues and provide a cash yield on equity. This holds debt at the initial

[15] Department for Energy Security & Net Zero (2026), 'Advanced Nuclear Framework', February (last accessed 20 July 2026).
[16] A two-way CfD is a long-term contract between a generator and a counterparty that fixes an effective price (i.e. the strike price) against a market reference price: when the reference price falls below the strike price, the counterparty pays the generator the difference; when the reference price rises above the strike price, the generator pays the difference back. The implication is that the generator is insulated from both downside and upside wholesale price movements while retaining exposure to volume risk and to its ability to capture the reference price. The two-way feature distinguishes it from a one-way arrangement, which tops up low prices but allows the generator to retain the upside.
[17] A strike price of £89.50/MWh was agreed in the event that a second nuclear power plant would be developed; however, by the time that SZC was being considered, the commercial context for new nuclear investment had change significantly and HPC's CfD model was abandoned. The £89.50/MWh strike price seems to have had little, if any, relevance to the SZC financial negotiations that resulted in a different balance between equity risk and return. National Audit Office (2017), 'Hinkley Point C', 23 June, p. 4 (last accessed 22 August 2026).
[18] Ibid., p. 53.

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principal rather than capitalising it while meeting institutional investors' requirement for a steady return.

- The cash equity yield is related to the allowed equity return agreed with the government at FID (10.8% and subject to a contractual cap, with the excess capitalised into the RAB.[19]
- The realised yield depends on performance against construction cost and schedule targets.

In addition, construction risk is partially shared. Capital costs exceeding the risk-adjusted 'project baseline', and up to a 'lower threshold' approximately 6% above baseline, are largely borne by consumers. Incremental cost overruns up to a 'higher threshold' approximately 25% above baseline are shared equally between investors and consumers. Beyond this, the government has considerable discretion over how, and whether, to proceed.[20] The SZC project reached FID in July 2025 at an estimated £38bn, with the government taking an initial 44.9% equity stake alongside La Caisse (20%), Centrica (15%), EDF (12.5%) and Amber Infrastructure (7.6%). The National Wealth Fund provided a term loan of up to £36.6bn, with a further £5bn of commercial lending supported by a Bpifrance Assurance Export guarantee.[21]

Whereas during construction investors accept contractual parameters agreed at FID, during operations they hand determination of future returns to the regulator. The Post Construction Review (PCR) that is due to take place three years after the Commercial Operation Date (COD) marks the transfer of regulatory authority from government to Ofgem and the start of quinquennial price control reviews. One of the principal outcomes of the PCR will be for Ofgem to determine the cost-of-capital parameters used to determine the forward-looking allowed costs of debt and equity, gearing, and the 'regulated WACC'.

European decisions combine a CfD with substantial state capital but stop short of charging consumers during construction or sharing overruns with them. They occupy the middle portion of the spectrum, socialising residual risk through the taxpayer rather than the consumer. The following reflects information available as of August 2026.

- **Czechia's** package for Dukovany, approved in April 2024, comprises a 40-year two-way CfD with a state-owned offtaker,

[19] National Audit Office (2026), 'Sizewell C', 30 May, p. 9 (last accessed 27 August 2026).
[20] Ibid., p. 7.
[21] Ibid., p. 40.

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a subsidised state loan covering most construction costs, and protection against policy change. Following expansion to two units, the Commission opened an in-depth investigation in December 2025, with the loan then estimated at €23bn–€30bn.[22]

- **Poland's** package for Lubiatowo-Kopalino, approved in December 2025 for a project of circa €42bn, combines an equity injection of around €14bn, guarantees covering all project debt, and a 40-year two-way CfD with the strike price confined to the funding gap.[23]
- **France's** EPR2 programme, at an estimated €72.8bn for six reactors, was notified in late 2025 based on a subsidised state loan covering at least half of construction costs and a 40-year CfD capped at €100/MWh.[24]

In the European context, the direction of travel is towards heavier state capital participation with tighter conditionality on the revenue mechanism. However, none of these packages so far address the compounding of interest during construction as the RAB does; instead, the governments lend cheaply or rely on loan guarantees and other risk transfers to reduce financing costs.

Pricing construction risk

Nuclear construction risk is intense, prolonged, and then it ends. It also has both 'systematic' and 'idiosyncratic' risk components.

The systematic part relates to, for example, exposure to input cost inflation, scarcity of nuclear-qualified supply chain capacity, and interest rates, all of which correlate with economy-wide 'bad states' (e.g. recessions, inflation shocks, financial crises, war) when capital is more likely to be scarce and expensive.[25] This component is priced using standard asset pricing models—typically the Capital Asset Pricing Model (CAPM)—and cannot be eliminated by regulation or policy alone, only reallocated to those parties willing to bear risk at lower cost.

The remaining risk is idiosyncratic, including project-specific risks such as delays, defects, and other completion risks that should in theory be

[22] EU state aid cases: SA.58207; SA.117794.
[23] EU state aid case: SA.108707.
[24] EU state aid case: SA.119469.
[25] The examples of 'bad states' given here are systematic risk events with macroeconomic consequences. In these periods, aggregate consumption falls, and the marginal utility of consumption rises; that is, consumers intrinsically ascribe more 'utility' to cash flows when there is less to go round. An asset (or project) that delivers losses (or cost increases) in these periods is therefore less attractive, and investors demand a higher return.

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diversifiable and require no additional risk premium. However, because of the absence of insurance markets, capital indivisibility, and the fact that the costs of financial distress accelerate as losses and liabilities increase (relative to the sponsor's available financial resources),[26] these can make an idiosyncratic risk premium necessary unless shared with the state.

Both risk components resolve once a nuclear plant is commissioned, which is why under a CfD model a single discount rate applied across a nuclear reactor's life treats a time-limited risk exposure as a permanent uplift, with corresponding adverse impacts on consumers' costs and intergenerational equity.[27] In comparison, the RAB model deliberately enables the discount rate to vary across construction and operations.[28]

Importantly, an asset whose risk profile changes discontinuously cannot, in general, be correctly valued with a single discount rate, yet the dominant convention—a project WACC held constant across the asset's economic life—does precisely that. A single discount rate is defensible only under specific conditions that pertain to how risk evolves over time. To the extent that these are unlikely to hold in practice, period-specific adjustments to either discount rates or cash flows are required.[29]

The RAB model implements this directly. SZC's real initial WACC of 6.7% ('vanilla', real; approximately 8.1% post-tax nominal) set at FID applies through construction and initial operations.[30] At PCR, Ofgem determines a 'regulated WACC' for the first price control period (during the operations phase) on a forward-looking basis.

This creates an obvious concern since the PCR gives Ofgem discretion over the return on an asset whose capital is by then wholly sunk. That said, SZC's regulatory risk exposure may be more tolerable than it initially appears given that investors have three decades of experience

[26] Put differently, a loss twice as large does more than twice the damage.
[27] This is the case for HPC's CfD, but European CfD regimes are subtly different because specific construction phase risk transfers have in some cases been put in place. Instead of the sponsor bearing all cost overruns, the state or consumers may bear some portion of these instead.
[28] Under the European CfD model, multiple discount rates are difficult to implement because EU state aid precedents do not support any mechanism that would allow a government to commit to a 'floor' rate of return on invested capital over the life of a nuclear plant (or a functionally equivalent measure) in a similar manner to what the UK government was able to do for SZC.
[29] Myers, S. and Turnbull, S. (1977), 'Capital budgeting and the capital asset pricing model: good news and bad news', *Journal of Finance*, May, pp. 321–333 (last accessed 30 August 2026).
[30] Assumes: 65% gearing, 2% expected inflation, 25% corporate tax rate, 4.5% cost of debt (pre-tax, real) and 10.8% cost of equity (post-tax, nominal). A comparison with HPC's 9.2% WACC (post-tax, nominal) would also need to account for changes in the corporate tax rate and gearing. See: Centrica (2025), 'Investment in Sizewell C', 22 July, p. 4 (last accessed 20 April 2026).

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of RAB remuneration experience in GB, also administered by Ofgem, against which to price that commitment.

More importantly, **the PCR changes the nature of investment rather than its price: because investors expect to realise value backed by Ofgem's commitment to the RAB value at PCR, a 60-year asset arguably becomes a 15-year asset for pricing purposes**.[31] That addresses the duration and cash-yield constraints that otherwise threaten to exclude institutional capital from the construction phase, and marks the point at which construction-risk capital exits and lower-cost operational-risk capital takes its place.

A second, less visible efficiency arises from enabling revenues during construction. Capitalised financing costs accrete at the allowed return, whereas consumers at large (i.e. 'society') are often assumed to value deferring consumption at roughly half that rate.[32] **Deferral therefore transfers value away from consumers in proportion to the difference between these rates, compounding and accumulating during the construction period**. During the operations phase, consumers continue to fund the RAB at a rate above the one at which they discount.

Under a CfD, neither of these efficiencies is available. In fact, the detriment to consumers is comparatively greater: all financing costs are deferred to the operations phase, implying that the accumulated revenues that need to be recovered are greater. Also, the CfD discount rate during operations remains fixed, making it difficult to reduce this if financing costs reduce and capital market conditions improve. Consumers could therefore be locked into higher electricity bills for longer. Moreover, **under a CfD, the barriers to private capital financing nuclear are arguably greater, implying that taxpayers would be funding a greater share of nuclear costs, and underwriting more risk, than may be the case under a RAB**.

[31] Centrica, an SZC shareholder, has valued its investment on the basis of forecast cash flows to PCR and a RAB valuation multiple of 1.0, implying that it expects to be able to divest its shareholding at that time (end-2039), 15 years after FID (July 2025), without any loss of value. See: Centrica (2025), 'Sizewell C: Regulated investment with predictable returns', 22 July, p. 24 (last accessed 20 April 2026); Centrica (2025), 'Investment in Sizewell C', 22 July, pp. 1, 4 (last accessed 20 April 2026).
[32] HM Treasury (2026), 'Discounting: Green Book Supplementary Guidance', February (last accessed 5 August 2026).

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6 Scaling from plants to programmes

Investors assessing advanced nuclear technologies face a shortage, but not an absence, of relevant evidence. Sixty years of gas-cooled heavy water and fast-reactor programmes across three continents offer a substantial record of what determines whether a novel design becomes a deployed fleet. That record is instructive precisely because it is unflattering. Recurring failures were not licensing refusals but bespoke design, overambitious technology scale-up, materials behaviour emerging decades into operation, and undefined back-end strategies. The following section draws out those lessons and their implications for today's programmes.

UK Magnox and high-temperature gas-cooled reactors (HTGRs)

Starting in the 1950s, **the UK licensed 26 Magnox and 14 AGR units under a goal-setting, non-prescriptive regime that embedded no light-water presumption**, demonstrating that a technology-agnostic framework can accommodate genuinely novel designs.

The gas-reactor knowledge remains an asset, even as the programme's failures were systematic. For example, X-energy recognised the UK's AGR experience when entering the Xe-100 into the Office for Nuclear Regulation (ONR) Generic Design Assessment (GDA) in June 2026.[33]

Design was bespoke. Magnox was built by five consortia, with each new reactor meaningfully different from the others, and the AGRs came in four sub-variants across seven stations. Only Heysham 2 and Torness were true replicas, and they were by a clear margin the best performers. The scale-up was equally challenging: the Windscale AGR prototype was around 30MW against 600MW commercial units; and Dungeness B, ordered in 1965, did not generate until the early 1980s.

Most instructively, serious problems emerged during operation rather than at licensing. Mild steel corrosion in CO_2 forced permanent derating of several Magnox stations around 1970. Graphite brick keyway root cracking later became the AGR fleet's life-limiting mechanism, driving inspection outages and the closure decisions at Hunterston B and Hinkley Point B. Magnox cladding, which corrodes in water, forced reprocessing and created the Sellafield legacy that still dominates UK

[33] X-energy (2026), 'X-energy Submits Xe-100 HTGR for UK Generic Design Assessment', 2 June (last accessed 5 July 2026).

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decommissioning liabilities, resulting in fuel and cladding choices determining back-end strategy for 70 years. AGR lifetime-capacity factors ran well below international PWR norms throughout.

Indian pressurised heavy water reactors (PHWRs)

India took the opposite approach and obtained a different outcome. Cut off from Canadian cooperation after 1974, it indigenised the 220MW PHWR (11 reactors built during 1975–2000, and 4 reactors built during 2007–11), then stepped incrementally to unit capacities of 540MW (two reactors built during 2005–06) and 700MW (four reactors built during 2021–25).

Using a fleet definition of more than two reactors built in close succession, this implies that India achieved two separate 220MW PHWR fleets separated by seven years. Importantly, during the completion of the first fleet, 1975–2000, the typical construction duration reduced from around 151 to 121 months. Also, across the two fleets, the typical construction duration fell from 137 to 85 months.

In addition, India achieved a fleet of 700MW PHWRs, 2021–25, albeit with a much smaller number of units, whose typical construction durations increased progressively from 122 to 164 months. This highlights that scaling up reactors can reintroduce first-of-a-kind (FOAK) risks, and fleets may need considerably more than four reactors, and longer intervals between successive reactors, to generate sufficient learning-by-doing spillovers.[34]

To enable this, a complete domestic supply chain was built, though this took roughly three decades. Two constraints proved decisive and the lessons are transferable.

- Uranium shortages before the 2008 Nuclear Suppliers Group waiver severely depressed capacity factors, showing that a licensed and built plant may still not run.
- The Civil Liability for Nuclear Damage Act 2010 contributed materially to vendor and insurer concerns, particularly through supplier recourse, confirming that liability architecture is a core part of the 'investability' question.

[34] International Atomic Energy Agency Power Reactor Information System, 'Country Statistics' (last accessed 30 August 2026).

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Japan's HTTR[35] achieved full power in December 2001 and an outlet temperature of 950°C in 2004 after starting construction in 1991, but it was neither an experimental reactor nor the first commercial prototype for a HTGR. Instead, it was a test reactor, and so strictly did not fail to lead to commercial deployment. Indeed, the view at the time was that there was no commercialisation pathway for the HTGR before 2010 at the earliest, in part because the industrial heat use-case was not sufficient to motivate scaling up before then.[36] Eventually, the reactor restarted in 2021 under post-Fukushima requirements. This case study matters because its loss-of-forced-cooling testing generates the international dataset supporting the reactor technology's passive-safety claims, thereby supporting the safety case for reduced emergency planning zones. Meanwhile, fuel qualification, source-term analysis, probabilistic assessment, confinement performance and site characteristics continue to remain relevant. **The lesson for AMR policy is that while sustained public research investment is necessary for the evidence base, it is not sufficient to inform commercial deployment decisions**.

Russia's BN-800[37] entered commercial operation in 2016 after a 32-year construction period that included design changes following the Chernobyl accident. It was part of a 45-year sodium fast-reactor programme running from BOR-60 and BN-350 through to BN-600. The comparison with Japan's prototype sodium fast breeder reactor ('Monju') is instructive. Monju suffered repeated sodium leaks and fires throughout its life and a major fire in 1995. Whereas the Russian programme absorbed the impacts of Chernobyl (the BN-800 design is, in engineering terms, the largest operating HTGR in the world), Japan's programme never recovered. Same coolant, same failure mode, opposite institutional outcomes. **The lesson is that programme continuity can be determinative**.[38]

[35] High-temperature engineering test reactor.
[36] Jiang, D. et al. (2026), 'Coordinated control of the World's first multi-modular high temperature gas-cooled reactor power plant HTR-PM', *Nuclear Engineering and Technology*, January, p. 2 (last accessed 25 August 2026); Shiozawa, S. et al. (2001), 'Present Status and Perspective of HTGR in Japan', *Gas cooled reactors*, IAEA-CSP-14, 12 September 2002, pp. 307–320 (last accessed 25 August 2026).
[37] Sodium fast breeder reactor.
[38] Nuclear Engineering International (2016), 'BN-800 begins commercial operation', 3 November (last accessed 25 August 2026); Elm Technical Services (2026), 'A Global Overview of Generation IV Nuclear Reactor Technologies for 2026', June, p. 20.

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China's HTR-PM[39] entered commercial operation in 2023, 11 years after construction started, and preceded by the HTR-10 that reached criticality in 2000. This has demonstrated its claimed passive-safety behaviour. It has not been replicated at scale, principally because the capital costs per kW are not competitive, and its two-module-one-turbine configuration illustrates the potential loss of economies of scale that modular designs must overcome. **The lesson is that successful licensing and commercial viability are, as ever, separate questions**.[40]

Four US microreactor 'zero-power' criticality demonstrations[41] were achieved by July 2026 under Department of Energy (DOE) authorisation as part of its Reactor Pilot Program. The DOE authorisation route was a deliberate response to AI/data-centre-demand-driven urgency, designed to accelerate commercial licensing by allowing evidence on reactor physics and safety to accumulate outside the Nuclear Regulatory Commission's (NRC) constrained assessment capacity. Notably, private underwriting via NRI/Syndicate 1176 was available, indicating that insurance is available when the hazard is genuinely bounded. However, these cases should not be over-interpreted since zero-power criticality demonstrates fuel loading and neutronics, not materials performance under irradiation, availability or ageing. (Precisely where the UK programmes failed, years after licensing, as discussed earlier.)

The DOE's initiative has therefore deferred the regulatory and commercialisation risks. Each design would still need to obtain an NRC licence based on evidence that zero-power criticality testing does not provide. Also, the commercialisation pathway must find a route to long-term, secure fuel supply that does not yet exist at fleet scale, among other challenges. The UK's Windscale-to-commercial-AGR transition happened under similar circumstances where there was a powerful sense of national programme urgency, but although this makes commercial deployment more likely, it does not necessarily ensure better execution.[42]

Three lessons from these case studies are that:

[39] Pebble-bed high-temperature gas-cooled reactor.
[40] World Nuclear News (2023), 'China's demonstration HTR-PM enters commercial operation', 6 December (last accessed 25 August 2026).
[41] Antares Mark-0; Valar Atomics Ward 250; Deployable Energy Unity; and Aalo Atomics CTR.
[42] U.S. Department of Energy (2026),'U.S. Department of Energy Reactor Pilot Program' (last accessed 31 August 2026); U.S. Energy Information Administration (2026), 'Small modular reactors and microreactors under development in the United States', 27 April (last accessed 31 August 2026).

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- starting with a research reactor or prototype, **commercial deployment may be expected to take as long as 10–35 years**;
- while new reactors have historically been state funded, particularly during the research and development phase, recently the **availability of private capital to fund demonstration projects in the USA has increased dramatically alongside expected growth in power demand** driven by digitalisation, AI diffusion and the need for more data centre capacity;[43]
- **government initiatives targeted at accelerating commercialisation can deliver meaningful benefits**, such as validating reactor core physics (e.g. neutronics), thermal-hydraulic behaviour, fuel performance and the behaviour of materials under irradiation, as well as verifying associated computer simulations. Generating this evidence is costly and the first developer bears it, whereas subsequent movers benefit from regulators embodying this knowledge in their technical assessments and licensing processes. By enabling a 'batch' of competing developers to pilot their reactors in parallel, nuclear deployment is potentially faster, the implicit first-mover disadvantage is alleviated, and the availability of a research 'public good' is increased.

Implications for technology scale-up

Technology scale-up moves from experiment through full-power demonstration to proven commercial operation, then repeats the cycle for the next generation of commercial-scale units, building on accumulated experience. It requires validated fuel, materials, safety analysis, and experience with maintainability and operating performance.

The evidence base, not the regulatory framework, is often a binding constraint. Four jurisdictions have licensed or authorised non-light-water reactors within the last ten years, including under a post-Fukushima regime designed around light-water accidents. Accordingly, the narrative that 'regulators cannot handle novelty' does not generally apply. What is missing for most designs are the validated computer

[43] All four US microreactor demonstrations identified were funded by private equity and/or venture capital investors. See: Valar Atomics (2026), 'Announcing our $1B Series B Led By Sequoia', 4 August; Aalo Atomics (2025), 'Aalo Closes $100M Series B', 19 August; Deployable Energy (2026), 'Deployable Energy and Hornbeck Offshore Partner to Advance Maritime Nuclear Power', 17 August; Antares (2026), 'Antares Raises $470M Series C to Deploy Nuclear Microreactors for Critical Missions', 27 July. All accessed 31 August 2026.

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simulations that can help speed up technical assessments and licensing since this is a public-good research problem requiring access to test facilities and long lead times, not a regulatory-design problem.

Regulatory assessment capacity can be constrained. For example, Holtec's SMR-300 GDA (steps 1 and 2) was completed in March 2026, 6 months longer than the 24 months expected.[44] X-energy's Xe-100 GDA (steps 1 to 3) is expected to last to end-2029. Greater international regulatory collaboration and sharing of technical assessments could help loosen this constraint.

Reciprocity in licensing offers a significant efficiency gain, but this continues to be a distant prospect. The ONR (UK)–NRC (US) collaboration permitting direct transfer of NRC-approved documentation addresses a duplicated fixed cost that the market cannot resolve on its own. However, Russia, China, Japan and the USA each built their non-light-water regulatory basis independently but with limited mutual recognition, suggesting that while the case for reciprocity is strong, its realisation is not imminent.

Proportionality of the regulatory burden during licensing with respect to the hazard must be earned analytically, not granted by technology category. Reduced emergency planning zones for small-inventory designs are defensible only where evidence supports them, which is why the HTTR matters. The corollary is commercially significant: where hazard is genuinely bounded, private insurance is available, as the US microreactor underwriting example shows.

Scale-up should be incremental, as demonstrated by India's 220MW to 540MW to 700MW PHWR ladder and against the UK's 30MW to 600MW AGR leap.

Implications for programme roll-out

Programme scale-out is the repeated delivery of a stable design through an enduring industrial and financial system. It requires a multi-unit orderbook, a settled reactor design and configuration control, a capable owner–integrator, sequenced siting and grid connection,

[44] Office for Nuclear Regulation (2024), 'Holtec SMR-300 Step 1 GDA statement', 1 August (last accessed 29 August 2026); Office for Nuclear Regulation (2026), 'GDA Step 2 of the Holtec SMR-300: fundamental assessment', 31 March (last accessed 29 August 2026); World Nuclear News (2026), 'X-energy submits Xe-100 for UK regulatory assessment', 3 June (last accessed 29 August 2026).

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qualified suppliers and workforce, fuel and waste infrastructure, repeatable licensing, and financing that can recycle capital between units.

Disposability belongs at the front of the process. Magnox cladding determined UK back-end strategy for 70 years. Meanwhile, many advanced fuels lack a deployed, regulator-accepted end-to-end conditioning, transport and disposal route in their intended jurisdictions.

Standardisation and a continuous orderbook are key determinants of outcome, evidenced by both the UK's bespoke failure and India's serial success.

Design maturity, configuration control and a capable delivery organisation are also critical. Together, they mitigate the risk of common-mode failures (i.e. when a design defect, a fuel issue or an adverse regulatory finding can affect the whole fleet).

Programme continuity is decisive since capability depreciates when programmes stop. A programme unable to survive its first serious operational incident, as Monju's did not, should not begin.

Stability and predictability in the design of government support packages and market design is crucial for timely, repeatable investment. Stability in the design of government support packages facilitates greater investor familiarity, and this can help build investor confidence. As a history of investment and regulatory behaviour is established, regulatory risk may reduce, and time compression to FID can occur. This was demonstrated by the UK's adaptation of the RAB to nuclear, which benefitted from investors' familiarity with the RAB as applied to GB energy networks. In particular, the credibility of Ofgem's commitment to the RAB value enables greater recycling of 'construction-risk capital' by providing opportunities for lower-cost 'operational-risk capital' to take its place following completed construction.

Investors should consider what is a realistic baseline for new development. India's Prototype Fast Breeder Reactor (PFBR) began construction in October 2004 for operation in 2010, and reached first criticality on 6 April 2026 despite state backing, prior research experience and no financing constraint. AMR schedules promising commercial deployment within five to seven years may warrant scepticism.

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7 Conclusion

The WNA's 2050 nuclear expansion scenario highlights an ambition gap: roughly $250bn of annual investment could be needed over the coming decades against the $80bn delivered in 2025. Closing it requires an answer to why private capital does not flow easily to nuclear, because the design of appropriate instruments depends on which market and regulatory failures are binding.

The costs of nuclear power arise overwhelmingly from capital sunk amid deep uncertainty. Nuclear finance is not yet sufficiently liquid, and key markets for nuclear insurance and long-dated offtake do not yet exist, which would normally allocate nuclear risk to whoever can bear it most cheaply. Construction risk therefore remains inefficiently concentrated on parties less able to absorb it, and it is priced in the discount rate where it compounds.

Instrument design has nonetheless improved materially. The progression from HPC, through the European support packages, to SZC traces a spectrum for the degree to which financing costs are either capitalised or paid as incurred, and in how construction risk can therefore be shared. The strongest argument for the regulated model is its treatment of construction risk, which resolves during the construction phase: SZC's two-stage determination matches compensation to risk-bearing over time, whereas a single CfD strike price necessarily prices a temporary risk as a permanent one. That said, no nuclear RAB project has been completed anywhere, so the case continues to rest on modelling and analogy rather than outturn evidence.

Technology scale-up depends less on regulatory approval than on the evidence needed to achieve it. Four jurisdictions have licensed or authorised advanced reactors within the last decade, including under a post-Fukushima regime designed around light-water accidents, so the claim that regulators cannot accommodate novelty does not hold. What is generally missing are the validated simulation models that allow assessments to proceed efficiently, and these require test facilities and long lead times rather than reflecting a defect of regulatory licensing. Assessment capacity is a second constraint, which may be loosened over time with greater reciprocity between regulators. The ONR–NRC collaboration points the way, but Russia, China, Japan and the USA each built their own regulatory knowledge bases independently and mutual recognition remains distant.

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Programme roll-out is not a scaled-up version of project delivery. The repeated construction of a stable design requires an industrial and financial system built to endure, which is supported by targeting regulatory measures at recognised market failures. Design maturity, configuration control and a capable owner–integrator limit the fleet-wide exposure that a single defect or adverse regulatory finding can create. Standardisation and a continuous orderbook separate India's serial success from the UK's bespoke failure. Continuity is important because capability depreciates when programmes stop. Disposal routes must be settled at the outset, since fuel choices may commit successors for decades, as Magnox demonstrated and many advanced fuels have yet to confront.

The financing dimension adds its own requirements. Stability and predictability in support arrangements build the investor familiarity that compresses regulatory risk and time to FID, as the adaptation of the RAB to nuclear illustrates. and a credible commitment to the RAB value is what allows construction-risk capital to be replaced by cheaper operational-risk capital once construction is complete. Case studies also counsel realism about time. India's prototype fast breeder began construction in 2004 for operation in 2010 and reached first criticality in April 2026, with state backing, prior research experience and no financing constraint. Schedules promising commercial deployment of advanced designs within five to seven years should be read against that baseline.

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8 Glossary

Advanced gas-cooled reactor (AGR): a Generation II British design using graphite-moderated carbon dioxide gas to cool enriched uranium oxide fuel. Its exceptionally high operating temperatures match fossil-fuel-plant steam conditions, allowing for highly efficient electricity generation.

Advanced modular reactors (AMRs): a sub-category of next-generation (Generation IV) reactors that use novel coolants—such as helium gas, liquid metal or molten salt—and work at much higher temperatures than conventional water-cooled reactors.

Fast reactor: an advanced Generation IV reactor that runs without a moderator, allowing fast-moving neutrons to split fuel. It typically uses liquid metal or molten salt coolants, enabling it to breed its own fuel and burn existing nuclear waste.

Fast breeder reactor (FBR): a specialised sub-type of fast reactor configured to produce more fissile fuel than it consumes. By surrounding its unmoderated core with a fertile material blanket (e.g. thorium or uranium-238), it converts low-value isotopes (in terms of fissile utility) into fresh, usable nuclear fuel (e.g. uranium-233 or plutonium-239).

Fusion reactor: a next-generation technology that generates energy by fusing light atomic nuclei (like hydrogen isotopes) under extreme heat and pressure. It produces zero long-lived radioactive waste and carries no risk of a meltdown.

Generic Design Assessment (GDA): the formal regulatory process used by UK authorities (the Office for Nuclear Regulation and the Environment Agency) to assess the safety, security and environmental impact of a nuclear reactor design before site-specific construction begins.

High-assay, low-enriched uranium (HALEU): enriched uranium that has a higher concentration (>5% and ≤20%) of the uranium-235 isotope by mass than 'low-enriched uranium' (LEU), making it more energy dense. HALEU demand is expected to increase as the next generation of advanced nuclear reactors that rely on different physics are deployed. These reactors are expected to be smaller and more deployable, better able to operate flexibly (i.e. 'load following'), able to achieve higher technical availability due to longer fuel cycles, and more efficient in terms of fuel utilisation.

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High-temperature gas-cooled reactor (HTGR): an advanced, Generation IV design using graphite-moderated helium gas to cool a core of highly resilient, meltdown-proof TRISO fuel. It produces exceptionally high-temperature heat optimised for heavy industrial applications or electricity generation. While similar to the UK's Generation II AGRs described above, Generation IV HTGRs benefit from improved materials and engineering that enable TRISO and improved safety performance. X-energy's Xe-100 reactor is a HTGR.

Light-water reactor (LWR): Generation III/III+ technologies that are also the world's most dominant commercial reactor category. These reactors use ordinary water as both the coolant and neutron moderator. It requires LEU fuel and must operate under immense pressure to prevent the water from boiling. Flamanville 3, Hinkley Point C, Holtec's SMR-300, Olkiluoto 3 and Sizewell C are all LWRs.

Magnox Reactor: a legacy, Generation I British design that uses natural uranium metal fuel encased in magnesium-alloy cladding. It relies on a graphite moderator and a carbon dioxide gas coolant, and was optimised for civilian power and military plutonium production.

Pressurised heavy-water reactor (PHWR): a Generation II reactor type—pioneered by the CANDU design—that uses heavy water (deuterium oxide) as both coolant and moderator. Its superior neutron efficiency allows it to run on natural, unenriched uranium fuel.

Small modular reactors (SMRs): advanced fission reactors producing up to 300MW of electricity. They are manufactured in factory modules and shipped to sites, offering faster, lower-cost construction and scalable power compared to traditional large-scale nuclear plants.

Thorium: a naturally occurring, weakly radioactive element that can be used as an alternative nuclear fuel. It must absorb neutrons to convert into fissile uranium-233, offering potential advantages in abundance, proliferation resistance and waste reduction.

Tri-structural isotropic (TRISO): a nuclear fuel spherule (<1mm diameter) that can be embedded in a graphite matrix to manufacture larger fuel pebbles or pellets and that is expected to be used extensively by HTGRs.

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Contact

Jostein Kristensen
Senior Advisor
+44 (0) 20 7776 6611
jostein.kristensen@oxera.com

oxera.com