BACK TO THE FUTURE? WHAT IT WILL TAKE TO DELIVER NUCLEAR ENERGY IN THE EU

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Summary

Nuclear energy has returned to the centre of European energy debates. Politically, this broader openness to nuclear reflects growing concerns over energy security, strategic autonomy, industrial competitiveness and the increasing need for 'homegrown' low-carbon energy. This CEPS In-Depth Analysis report takes stock of the current state of nuclear energy in the EU and assesses the key challenges and conditions required for its future deployment.

The analysis suggests that expanding nuclear capacity in the EU is far from straightforward and will require simultaneous and coherent action by industry, Member States and the EU. Industry faces the challenge of rebuilding supply chains, strengthening project delivery capabilities beyond a legacy of chronic delays and cost overruns, and future-proofing new technologies. To support this, Member States willing to pursue nuclear remain responsible for ending stop-and-go cycles, providing long-term political commitment and regulatory predictability, and establishing financing frameworks capable of de-risking highly capital-intensive investments that require a long-term planning horizon.

While primary responsibility for deployment remains with Member States and industry, greater policy engagement and regulatory coherence at EU level is needed. The expansion of EU climate, energy, environmental, industrial and financial policies over recent years has increasingly shaped regulatory, financing and market incentives affecting nuclear energy. Yet progress towards a more coherent EU approach remains constrained by persistent divergences among Member States regarding the role of nuclear energy.

Nuclear energy's future role will also depend on its ability to adapt to an electricity system that is increasingly shaped by variable renewable generation and growing flexibility needs. Reconciling the operational and economic characteristics of nuclear power with evolving market structures is likely to become one of the defining challenges over the coming decades.

While political support for nuclear energy has strengthened considerably, translating this momentum into actual deployment will require addressing a broad set of industrial, regulatory, financial and market barriers. Without such measures, renewed political attention in Brussels is unlikely to result in a sustained nuclear revival in Europe.

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Abbreviations

aFRR	Automatic frequency restoration reserve
AGR	Advanced gas-cooled reactor
AI	Artificial intelligence
AMR	Advanced modular reactor
BAT	Best available technology
BESS	Battery energy storage system
BWR	Boiling water reactor
CAPEX	Capital expenditure
CCfD	Carbon contract for difference
CCGT	Combined-cycle gas turbine
CCS	Carbon capture and storage
CEE	Central and Eastern Europe
CfD	Contract for difference
CHP	Combined heat and power
CISAF	Clean Industrial Deal State Aid Framework
CRM	Capacity Remuneration Mechanism
DAC	Direct air capture
DECEX	Decommissioning expenditure
DNSH	Do no significant harm
EDHC	Efficient district heating and cooling
EIB	European Investment Bank
EMD	Electricity market design
ENSREG	European Nuclear Safety Regulators Group
EPC	Engineering, procurement and construction
EPR	European pressurised reactor
ETS	Emissions Trading System
FCR	Frequency Containment Reserve
FFR	Fast frequency response
FID	Final investment decision
FOAK	First-of-a-kind
GCR	Gas-cooled reactor
GFM	Grid-forming inverter
HALEU	High-assay low-enriched uranium
HTGR	High-temperature gas-cooled reactor
HTE	High-temperature steam electrolysis
HVDC	High voltage direct current
I&C	Instrumentation and control
IAA	Industrial Accelerator Act

IAEA	International Atomic Energy Agency
IEA	International Energy Agency
IPCEI	Important Projects of Common European Interest
IRA	Inflation Reduction Act
JER	Joint early review
LBE	Lead-bismuth cooled reactor
LCOE	Levelised cost of electricity
LCOH	Levelised cost of hydrogen
LEU	Low enriched uranium
LFR	Lead-cooled fast reactor
LFSCOE	Levelised full system cost of electricity
LFSP	Load factor strike price
LMR	Liquid metal-cooled reactor
LOLE	Loss of load expectation
LTE	Low-temperature electrolysis
LTO	Long-term operation
LWR	Light water reactor
MED	Multiple-effect desalination
mFRR	Manual frequency restoration reserve
MOX	Mixed oxide
MR	Microreactor
MSF	Multi-stage flash
MSR	Molten salt reactor
NEA	Nuclear Energy Agency
NECP	National energy and climate plan
NOAK	N^{th}-of-a-kind
NPT	Non-proliferation Treaty
NZIA	Net-Zero Industry Act
O&M	Operation and maintenance
OECD	Organisation for Economic Co-operation and Development
OEM	Original equipment manufacturer
OPEX	Operational expenditure
PCI	Pellet-cladding interaction
PEM	Proton exchange membrane
PFR	Primary frequency response
PINC	Nuclear Illustrative Programme
PPA	Power purchase agreement
PV	Photovoltaic
PWR	Pressurised water reactor
R&D	Research and development

R&D&I	Research, development and innovation
RAB	Regulated asset base
RED III	Renewable Energy Directive (3rd Revision)
RES	Renewable energy source
RFNBO	Renewable fuel of non-biological origin
RO	Reverse osmosis
RoCoF	Rate of change of frequency
SFR	Sodium-cooled fast reactor
SMR	Small modular reactor
SNETP	Sustainable Nuclear Energy Technology Platform
SOE	State-owned enterprise
SOEC	Solid oxide electrolyser cell
SSC	Systems, structures and components
TFEU	Treaty of Functioning of the European Union
TRISO	Tri-structural isotropic
TRL	Technology readiness level
TSO	Transmission and system operator
VALCOE	Value-adjusted levelised cost of electricity
vRES	Variable renewable energy source
VSM	Virtual synchronous machine
WACC	Weighted average cost of capital
WCR	Water-cooled reactor

EXECUTIVE SUMMARY

In the EU, nuclear energy has seen renewed attention in recent years as a source capable of providing large volumes of dispatchable low-carbon energy and contributing to a more resilient and homegrown energy system during a period of heightened geopolitical tensions and growing energy security concerns. Although its share in the EU electricity mix has gradually declined over recent decades due to reactor closures, limited new construction, policy reversals and prolonged industry stagnation, the 8th Illustrative Nuclear Programme (European Commission, 2025a) projects nuclear capacity will need to be substantially renewed towards 2050, even under its baseline scenario.

Whether this renewed political interest will ultimately translate into the sustained deployment of new nuclear capacity is still to be seen. While deployment decisions remain primarily in the hands of industry and Member States, they are increasingly shaped by the EU's policy, regulatory and financial frameworks. This CEPS In-Depth Analysis report thus takes stock of the current state of nuclear energy in the EU and assesses the core challenges and conditions required for its future deployment, while recognising the interdependence between actions taken at industrial, Member State and EU levels.

This report reviews: (i) the evolution of nuclear energy within EU policy and regulatory frameworks, including the roots of divergent Member State positions; (ii) the role of nuclear in a transforming energy system, including its ability and limitations for load-following, system contributions and potential for greater non-electric applications; (iii) the economics of nuclear energy at plant-level and beyond for newbuild projects (and to a lesser extent, lifetime extensions), its competitiveness relative to other generation technologies and wider system costs, and the implications of evolving electricity markets for revenue adequacy; (iv) key challenges and enabling conditions for new nuclear deployment, including industrial capacity, workforce skills, supply chains and financing mechanisms; and (v) small modular reactors (SMRs) in the EU, including technology readiness, deployment barriers, potential applications and economic viability.

The report evaluates nuclear deployment against a set of criteria identified as critical for long-term success: durable political acceptance, regulatory predictability, revenue adequacy, access to financing and de-risking instruments, technology robustness, supply chain resilience, and construction performance and delivery capacity. Based on this assessment, the report identifies the prospects for deployment and provides recommendations for the way forward.

Targets and EU policies

Over the past three decades, EU climate, energy, environmental, industrial and financial policies have created an increasingly complex set of framework conditions affecting nuclear energy. While an EU-level approach to nuclear has matured in this political cycle, inconsistencies remain, and persistent disagreements among Member States continue to limit the emergence of a more coherent approach.

The absence of an EU-wide framework explicitly recognising the contribution of all low-carbon technologies remains a recurring concern among Member States pursuing nuclear energy. Nuclear's limited visibility and absence in EU-wide targets and national energy and climate plans (NECPs) are often perceived as a lack of equal footing. While agreement on a dedicated EU nuclear target appears politically unrealistic, post-2030 discussions may allow for improved accounting and better consideration of all low-carbon technologies within EU planning and governance processes. Beyond targets, greater attention must be paid to ensuring that nuclear energy and nuclear-based products are appropriately acknowledged across relevant policy and regulatory frameworks.

Nuclear's role and system value

Nuclear energy's traditional value lies in providing large volumes of dispatchable electricity alongside system services such as inertia provided by synchronous generation. In a system increasingly dominated by variable renewables and the need to phase out fossil-based thermal generation, nuclear's capacity to offer geographically independent, energy-dense and dispatchable capacity, as well as to remain one of the key inertia providers – including to adjacent countries – is still relevant.

While new nuclear facilities remain less competitive than most variable renewables on a pure levelised cost of electricity (LCOE) basis, the broader system costs associated with maintaining reliability, adequacy and network infrastructure to actually deliver energy should be further considered. This highlights the importance of system-level costs and nuclear's contribution to reducing wider/total system costs as being increasingly relevant, although results remain sensitive to modelling assumptions and system design.

Nuclear's high energy output also allows more room for potential coupling with hydrogen and e-fuels production, although the economics and business case need to be demonstrated. This involves both newbuild and long-term operation (LTO) reactors. Heat cogeneration represents an additional but more place-dependent option.

The economics of nuclear and electricity markets

The economics of nuclear are increasingly shaped by broader electricity market dynamics, with higher shares of renewables, more frequent periods of low or negative prices and growing pressure on nuclear's traditional baseload operating models. In the future, nuclear could thus be increasingly exposed to price-following operation.

While nuclear can technically carry out load-following operation in most cases, with appropriate modifications if needed, the economics have been conventionally based on high capacity-factor baseload operation. The electricity system's ongoing transformation requires a clearer analysis of the future of nuclear's baseload operation, particularly for Member States considering new nuclear investment. Long-term contracts, including industrial offtake agreements and Contracts for Difference (CfDs), may partly address this gap, but design details will be decisive.

Nuclear's system value also needs to be more explicitly reflected alongside further developments in market design. However, these additional revenues are likely to remain very marginal compared with electricity sales. Non-electric revenue streams have growth potential, but they will depend on the business case of these applications and EU regulatory incentives.

Financing new nuclear

Nuclear projects are highly capital-intensive with long construction periods and investment horizons exceeding 60 years. Nuclear's regulatory classification as a transitional activity under the EU Taxonomy, a compromise adopted after long political deliberations in the previous political cycle, continues to shape investor perceptions. At the same time, while private investment is increasingly needed, public de-risking mechanisms are expected to remain necessary for most new-build projects in the EU.

Three risks dominate financing: construction risk, price risk and volume risk. Construction risk is particularly critical, as delays and cost overruns directly increase financing costs and undermine bankability. Several models are emerging across Europe. Given increasing price volatility, CfDs are likely to remain central for mitigating the price risks of new nuclear, although how they are calibrated will be key. They have already been applied to new nuclear plants in Czechia and Poland, and a request was submitted by France. Growing electrification and industrial demand may also strengthen the case for long-term offtake agreements, particularly for industries that need firm low-carbon electricity supply. Again, to increase the attractiveness of nuclear for offtake agreements, it is essential to minimise construction risks, as lengthy deployment timelines and unpredictable costs reduce industry interest.

Construction performance and delivery capacity

The European nuclear industry faces a legacy of decades of underinvestment, weakened supply chains, skills shortages, stop-and-go political cycles and an uneven project delivery record. Long construction timelines, cost overruns, constrained industrial capacity and a shrinking workforce have become major concerns for investors and policymakers. While underlying causes vary, be it policy reversals, negative public perceptions, erosion of industry capabilities, design (im)maturity, regulatory stringency or any other factors, the end result is a persistent delivery gap that directly impacts financing conditions and investor confidence.

Rebuilding industrial capabilities is a prerequisite for any large-scale nuclear revival. This includes expanding manufacturing capacity, strengthening supply chains, restoring specialised skills and improving project execution capabilities. High construction risk remains a core bankability impediment and is reinforced beyond broader industrial delivery constraints by limited competition across a small number of engineering, procurement and construction (EPC) vendors.

At EU level, support remains limited. Euratom continues to provide research funding, Important Projects of Common European Interest (IPCEIs) are authorised and recent access to financing through InvestEU for SMRs all point in the right direction. But stronger – and more coherent – support for industrial scaling, innovation and supply-chain development is needed.

The growing role of non-EU technology vendors for both large-scale reactors and SMRs on the EU market raises broader questions regarding technological sovereignty, industrial competitiveness and strategic dependencies, as also reflected in the negotiations over the Industrial Accelerator Act (European Commission, 2026a). A lack of competition also becomes even more pressing – with only a few non-EU technology vendors remaining on the EU market, they face their own challenges in their domestic and international deployment strategies, reinforcing the complexity of supply choices in Europe.

SMRs

SMRs have recently come under the spotlight in Brussels, reflected in the 2024 establishment of the European Industrial Alliance on SMRs and the recent 2026 EU SMR strategy (European Commission, 2026b). However, despite their general framing as a relatively fast-to-deploy solution capable of addressing a range of application needs, many questions regarding SMR deployment remain to be resolved.

Most near-term deployments are based on Generation III reactor designs, with initial first-of-a-kind (FOAK) units expected to be deployed over the coming years. These should provide greater clarity on construction costs and timelines. More advanced Generation IV technologies remain further from commercialisation and are generally at earlier technology readiness level (TRL) stages in Europe. Overall, the global and European SMR design landscape across both generations remains fragmented, with a wide range of competing designs yet to converge and to demonstrate their investment potential and bankability.

Many of the barriers facing SMRs resemble those affecting large-scale nuclear projects, including financing and supply chains – but licensing is emerging as a specific challenge. The economic case for SMRs relies on standardisation, modular construction and serial deployment across multiple sites, meaning that fragmented national licensing systems risk undermining this logic. More fundamentally, there is a need to develop legal frameworks that enable regulators to rely, where appropriate, on assessments conducted by their counterparts in other jurisdictions, thereby avoiding unnecessary duplication and allowing for the streamlining of SMR licensing processes while preserving the ability of national regulators to address country-specific regulatory requirements.

In terms of funding signals, the InvestEU top-up of EUR 200 million represents a positive signal but remains modest relative to the scale of required investment. A stronger role for IPCEI and other Member State funding will be essential for enabling serial production at scale, alongside the need to rebuild industrial capacity largely from scratch – a challenge comparable to large-scale reactor deployment. Joint Member State orderbooks and closer cooperation on designs and supply chains will be essential, ultimately, for achieving significant cost reductions, which remain one of the central questions facing the sector.

While cost trajectories remain highly uncertain, the SMR business case will also depend on the end-use applications of SMRs. SMRs offer significant advantages because of their versatility, modular deployment and operational flexibility, enabling potential applications across a variety of settings, including both electric and non-electric uses, as well as hybrid configurations. However, this broad range of potential applications also creates uncertainty. The diversity of proposed use cases, combined with the wide variety of SMR designs at different TRLs, means that it remains unclear where – and in which applications – SMRs can deliver the greatest added value. If this ambiguity persists, it may weaken their competitiveness relative to more clearly defined alternatives and, ultimately, slow market development.

Early SMRs are expected to provide electricity generation, both on grid and for industrial clusters, potentially complemented by district heating and low-temperature industrial heat depending on local needs. From an industrial competitiveness perspective, SMRs may offer long-term value by providing dispatchable low-carbon electricity to industrial clusters without requiring the relocation of these (energy-intensive) industries. It is important, however, to note that high-temperature industrial applications – the cornerstone of deep decarbonisation for hard-to-abate sectors – will depend on Generation IV reactor designs advancing further.

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Overall, a sustained revival of nuclear construction in Europe is far from guaranteed. Political support is necessary but insufficient alone. The historical track record highlights structural constraints across industry, regulation and financing. Translating a renewed interest into actual deployment will require coordinated action across industry, Member States and the EU. The final section of the report provides thoughts and recommendations on how to move forward.

Introduction

Nuclear energy's ability to provide stable, low-carbon electricity over prolonged lifetimes has long made it an attractive generation source for energy systems across the world. In Europe, however, following a strong expansion in the 1970s and 1980s, the nuclear industry rapidly became a roller coaster. Accidents of varying degrees (caused by human error, technological failure, or natural events) amplified anti-nuclear movements and concerns over safety and waste management. Three Mile Island (1979), Chernobyl (1986) and Fukushima Daiichi (2011) stand out for their scale and lasting impact on perceptions of nuclear energy. As a result, nuclear energy has become a persistently divisive issue among national governments and in public opinion in Europe, while the nuclear industry itself has experienced a downturn over the past few decades.

At the same time, although nuclear was the cornerstone of European integration in the early stages of the EU under the Euratom Treaty (1957), its place in the energy mix and role in supporting the energy transition and climate objectives have been, at best, uneven at the EU level. On the one hand, nuclear has broadly remained an integral part of EU energy and decarbonisation strategies, with the Euratom Treaty Article 1 mandating 'creating the conditions necessary for the speedy establishment and growth of nuclear industries' and Article 194(2) of the Treaty on the Functioning of the European Union (TFEU) reaffirming that Member States retain the right to determine their own energy mix. On the other hand, its role has remained ambiguous and frequently contested across EU targets, key regulatory and strategic files, and implementation mechanisms. This has resulted in a fragmented and often uneven treatment of nuclear energy within EU frameworks alongside the gradual expansion of EU competences in areas such as the internal energy market, climate, environment, and industrial policy throughout the past three decades.

Now, however, there are increasing signs of a willingness to engage in a dialogue in Brussels about a role for nuclear in the future EU energy system. This has been supported by political recognition, for example, by the European Commission (Commission) President Ursula von der Leyen's explicit endorsement at the Nuclear Energy Summit in March 2026. She indicated that 'it was a strategic mistake for Europe to turn its back on a reliable, affordable source of low-emissions power'.

Several factors may have accounted for this notable shift. First, with the energy transition becoming increasingly cost-sensitive, and alongside geopolitical shocks and the EU's growing exposure to them, the current political cycle (2024-2029) has reiterated the urgency of both lowering energy prices and ensuring their (relative) stability. This has gradually framed the energy transition around 'homegrown' energy, with strengthened domestic cleantech manufacturing capacity. Second, a transition to a power system with a high level of renewables has introduced new challenges and concerns: the need to engender flexibility beyond gas-fired generation, system adequacy with an increasingly retiring thermal power fleet, future grid stability, and rising system costs. Third, there is also a growing recognition that scaling up electrification alongside low-carbon power generation is more complex than previously anticipated – but also increasingly necessary – amid expectations of sustained growth in electricity demand.

Given its inherent ability to provide dispatchable, low-carbon power supply, nuclear energy could enjoy a second wind in the EU (Annex 1: Nuclear energy in the EU provides an overview of the current state of nuclear in the EU). This momentum is a positive signal for the European nuclear industry. The industry, however, needs to address its own structural challenges to ensure effective EPC delivery and resilient supply chains. Only a few new reactors have been built in Europe since the 1990s, having often faced persistent cost and schedule overruns. Equally, the business case for new nuclear projects will need to prove robust, with adequate and predictable revenue streams, viable financing models and stable policy frameworks to be provided by Member States.

This study seeks to assess whether and how the renewed interest from Brussels can translate into a sustained revival, rather than another cyclical 'nuclear renaissance' talk with high expectations but limited delivery, as happened in the mid-2000s. The study aims to provide an overview of the current state of nuclear energy in the EU, its contributions to the energy system and the challenges it faces across economic, industrial, and regulatory dimensions, with the ultimate objective of understanding the environment for its development at the EU level.

Methodology and data basis of the report

To assess the prospects of nuclear energy in the EU, the report relies on a set of criteria adapted from Spokas and Ricks (2026). These criteria capture the key conditions and main risks that determine whether nuclear energy can effectively contribute to the EU's energy security and transition, from economic viability to system integration and delivery capacity (Figure 1). The criteria are assessed throughout the report in the respective sections and consolidated in a final assessment in the conclusion.

The study focuses on commercially available Generation III/III+ (Gen III/III+) reactors, which today are principally represented by GW-scale designs, alongside emerging SMR designs approaching commercial deployment (a technology overview is provided in Annex 2: Overview of nuclear reactor technology). Generation IV (Gen IV) technologies are discussed insofar as they remain at earlier stages of technological maturity and research, development and innovation (R&D&I). Further details on the methodology can be found in Annex 3: Methodology (extended).

Figure 1. Assessment criteria

Durable and widespread political acceptance	Section 1	The degree of sustained political acceptance of nuclear energy among Member States which have chosen to pursue nuclear power, and the stability of that support over time across political cycles. At EU level, this refers to the extent to which there is a functional agreement that nuclear fully contributes to EU climate and energy objectives and can therefore (fully) access and operate within EU policy and financial instruments.
Regulatory predictability	All sections	The predictability and coherence of EU and national regulatory frameworks affecting nuclear energy, including targets, classification of low-carbon technologies, and the extent to which policy instruments are applied to nuclear on par with other low-carbon sources.
Revenue adequacy	Sections 2 & 3.2	The extent to which electricity sales and other remuneration mechanisms, including from nuclear-based products and their contribution to system stability, ensure stable revenues that can support the recovery of capital-intensive nuclear investments.
Access to de-risking instruments and finances, and EU funding	Sections 4.1.1 & 4.2	The availability of state-backed risk-sharing mechanisms (at EU and Member State level), such as guarantees, loans or CfDs, to support investment in nuclear projects. The extent to which nuclear projects are eligible and can access EU-level financing instruments and low-carbon energy funding frameworks.
Construction performance and adequate delivery system	Sections 4.1.1–4.1.3	The exposure to cost escalation and delays during project delivery, which significantly affects project bankability and investment attractiveness. The availability of skilled labour, engineering capacity, and experienced EPC consortia capable of delivering nuclear projects on time and within budget.
Technology robustness	Sections 4.1 & 5.1	The (un)certainty related to technology maturity and performance, including industrial readiness, dependence on non-EU technology vendors, and strategic autonomy considerations.
Robust supply chains	Section 4.1.2	The existence and resilience of industrial supply chains capable of supporting large-scale (hereafter gigawatt- '(GW)-scale') nuclear construction, including critical components, fabrication capacity, and the ability to scale SMR deployment.

Limitations of the report and disclaimers

This report does not delve into nuclear waste management and safety issues. While societal acceptance, particularly at the local level, is widely recognised as a critical factor for nuclear deployment (Bogdanowitz et al., 2025; Hornung, 2023), it also lies beyond the scope of this study. Rather, the study focuses on political acceptance, understood here as being largely shaped by Member State domestic political processes and political dynamics within and among EU institutions.

Overview of the report

The report comprises six sections that build on the analytical framework set out above.

Section 1 examines the evolution of political acceptance at the EU level, as well as Member State positions on the role of nuclear in the energy mix and decarbonisation strategies. It introduces the EU policy and regulatory frameworks relevant to nuclear energy that are further assessed throughout the report.

Section 2 focuses on the system value of nuclear. It discusses its role in a high-renewables, increasingly integrated EU electricity system, including provisions for system and grid stability, load-following capabilities, the impact on total system costs, and sector integration beyond its electric value.

Section 3 examines the economics of nuclear. It looks at plant-level cost considerations, existing remuneration mechanisms, and the stability of revenues from electricity sales under the current electricity market design (EMD).

Section 4 discusses the enabling conditions for new nuclear power plant construction (hereafter 'newbuilds'), including the industry's capacity to deliver projects on time and within budget, the state of the supply chain, and the financing and risk allocation mechanisms.

Section 5 addresses the prospects and feasibility of SMRs, focusing on their technological maturity, scalability, and potential role in future nuclear deployment pathways.

The *conclusion* provides an overall assessment of nuclear energy in the EU against the identified criteria discussed in sections 1-5 and policy recommendations.

1. EU POLICY DYNAMICS ON NUCLEAR ENERGY

Nuclear energy in Europe has long been shaped by Member States, reflecting diverging national preferences over the energy mix and, more recently, different decarbonisation pathways. The gradual expansion of EU competences into areas relevant to nuclear deployment and operation, including energy market integration, climate policy, State aid, sustainable finance, and industrial policy, has brought nuclear energy debates into more prominence at EU level. In turn, this has further intensified policy debates at EU level, as longstanding divergences among Member States on nuclear energy increasingly spill over into EU policymaking.

This section explores the evolution of the role of nuclear energy in Europe, outlining the difficulties of a common approach on nuclear at EU level (section 1.1); EU policy developments regarding nuclear energy in the last two political cycles (section 1.2); and the positioning of nuclear energy within EU regulation and policies discussed throughout this report in section 1.3.

1.1. EVOLUTION OF NUCLEAR'S ROLE IN THE EU

As one of the founding treaties of European integration, the Euratom Treaty (1957) carried significant expectations that it would drive nuclear deployment. Famously hailed as 'too cheap to meter' in the 1950s, nuclear formed 'part of the post-Second World War consensus of economic growth' (Müller and Thurner, 2017, p.3). This translated into large-scale planning and construction of nuclear capacity across industrialised economies from the 1950s onwards, with the first Western atomic reactor for electricity production at the Calder Hall nuclear power station in the UK, followed by rapid expansion across Europe.

However, these expectations did not fully materialise in Europe (Huhta, 2025). With nuclear policy remaining within Member State competence, EU-level policies under Euratom were largely confined to setting radiation protection guidelines and facilitating nuclear research and non-proliferation (Johnson, 1999). Some Euratom loans were used to support the construction of prototypes and experimental projects, but one of its core activities centred on the preparation of Nuclear Illustrative Programmes (PINC), periodically published by the Commission and primarily focused on providing an overview of nuclear sector developments and facilitating associated discussions on nuclear development projections. Initial PINCs were prepared in 1966, 1972, and 1984.

Peak enthusiasm for nuclear energy in Europe was arguably reached in the 1970s. The oil crisis of 1973-1974 heightened concerns about dependence on conventional fuel sources, particularly in the context of reliance on Middle East imports and highlighted the urgency of alternative energy supplies. In response, several European countries rapidly advanced their nuclear programmes: the UK commissioned multiple reactors between 1962 and 1973; Italy began operation in 1963; in 1965, Sweden decided to develop nuclear power to complement hydropower; the first commercial nuclear power plant in Germany came online in 1969; and in 1974, France launched an unprecedented nuclear construction programme. During this period, opposition to nuclear energy had not yet entered the political mainstream, with Austria being a notable exception following its 1978 referendum rejecting nuclear energy – a position that continues to strongly shape the country's political stance on nuclear energy at EU level.

From the late 1970s onwards, however, nuclear energy became increasingly entangled in public sensitivities and anti-nuclear political debate. This focused on civilian concerns about nuclear's safety risks, waste management, uranium mining, and the use of large-scale public finance support. The Three Mile Island accident in the US in 1979 marked an early turning point in public perception in Europe. In some countries, anti-nuclear positions became entrenched. Sweden held a referendum in 1980 that resulted in a moratorium on nuclear expansion. In 1984, Spain decided not to commission any new nuclear power plants, with Denmark following in 1985.

But it was the Chernobyl accident in 1986 that formed a major dividing line. The disaster significantly strengthened anti-nuclear sentiment and heightened safety concerns across Europe. A series of moratoria on new nuclear construction followed. Italy (in 1987) and Belgium (in 1988) decided not to proceed with new nuclear reactors. Finland voted against the construction of a new nuclear reactor in 1993, despite earlier approvals, and Spain put a complete break on new nuclear developments in 1994. In practice, after Chernobyl, almost all Member States except for France (at this time the EU-15) halted new construction. Chernobyl started a period of gradual stagnation for the European nuclear industry. The fourth PINC programme was delayed (and only adopted in 1997), and the 1995 Green Paper 'For a European Union energy policy' noted 'a lack of consensus regarding the future of nuclear energy', which at the time generated 34% of EU-15 electricity production, and indicated that 'the future of nuclear power remains dubious'.

The growth of green parties across Member States since the late 1990s further elevated nuclear issues on the political agenda (Johnson, 1999), and the phase-out of nuclear energy gained traction. For example, Germany announced its nuclear phase-out in 2000 (with the timeline changing several times and accelerated after the Fukushima Daiichi accident in 2011), and Belgium adopted a nuclear phase-out law in 2003. Similar political discussions were held in Spain around 2004, although its phase-out policy was not formalised until 2019. Over time, these policies were repeatedly revisited, with closures, lifetime extensions, and policy reversals introduced depending on domestic political cycles, alongside increasingly ageing nuclear fleets.

At the same time, Chernobyl also prompted a strengthening of the EU's role in nuclear safety. The European Community Urgent Radiological Information Exchange (ECURIE) was established the year after the disaster, and a more robust secondary regulatory framework on nuclear safety was gradually developed. The early 2000s saw renewed efforts to deepen EU involvement in nuclear safety. In 2002-2003, the Commission published ambitious proposals (the 'nuclear safety package') to take steps towards more coherent nuclear safety and radioactive waste management. While the proposal was not adopted, primarily because Member States had different sensitivities towards harmonising nuclear safety standards, the European Court of Justice (ECJ) (Case C-29/99) clarified that nuclear safety could not be artificially separated from radiation protection, confirming that EU competences under the Euratom treaty apply to nuclear safety. It was only in 2009 that the EU adopted its first legally binding nuclear safety framework, the Nuclear Safety Directive (2009/71/Euratom), followed by the Waste Directive (2011/70/Euratom). These frameworks established common minimum safety and waste management principles, while maintaining national responsibility for regulatory oversight and limiting the scope of direct EU-level authority, thereby reinforcing the central role of national regulators.

During the 2004 EU enlargement, nuclear safety became a central issue for the accession of new Member States. Nuclear safety requirements saw 'Chernobyl-type' RBMK-1500 (Ignalina in Lithuania) and VVER-440 units (Kozloduy 1-4 in Bulgaria, Bohunice 1-2 in Slovakia) closed as part of EU accession.

In 2000, the Green Paper 'Towards a European strategy for the security of energy supply' framed nuclear energy as 'the undesirable' and 'a source of energy in doubt' and re-emphasised the importance of nuclear safety. Yet despite uncertainty over nuclear energy, the idea of a 'nuclear renaissance' periodically re-emerged in EU policy debates and the academic literature (Nuttall, 2004). Concerns over growing dependence on imported oil and natural gas – resurfacing in the mid-2000s – renewed EU interest in nuclear energy (Vanhecke, 2007; Sovacool, 2011). A more positive shift emerged in 2006, when the Green Paper 'A European Strategy for Sustainable, Competitive and Secure Energy' called for 'a transparent and objective debate on the future role of nuclear energy in the EU', also in the context of growing attention to greenhouse gas emissions and climate mitigation. It was a reminder that nuclear was 'the largest source of largely carbon-free energy in Europe' at that time.

Reflecting growing concerns linked to an ageing and gradually retiring nuclear fleet, the 5th PINC (2007) raised questions about lifetime extensions, newbuild, and licensing harmonisation. While nuclear still maintained a significant share in electricity generation in the mid-2000s, particularly in some of the new Member States from Eastern Europe, Member State policies continued to oscillate between phase-out and revival depending on domestic political cycles. Only a limited number of new projects were initiated in the mid-2000s, notably Olkiluoto 3 in Finland (construction started in 2005) and Flamanville 3 in France (2007), while the Mochovce 3 project in Slovakia (1987) experienced extremely long construction timelines. In addition, the prevailing trend across OECD countries was a shift from coal to natural gas. The shale gas revolution in the US, in the meantime, contributed to lower global natural gas prices, further weakening the competitiveness of newbuild nuclear. In contrast, China embarked on an ambitious nuclear buildout from the early 2000s and, by the late 2010s, had become the main driver of global nuclear capacity additions.

The Fukushima Daiichi accident in 2011 marked another watershed moment. EU-level safety regulation was tightened through the revision of the Nuclear Safety Directive (2014/87/Euratom) and the EU-wide stress tests (2011-2012). Coordinated by the European Nuclear Safety Regulators Group (ENSREG), these stress tests assessed reactor resilience to extreme events and were followed up with peer reviews and national action plans to improve safety standards. Tightened regulatory oversight that followed, however, often led to longer timelines for both new construction and existing fleets (section 4.1.1).

Responses to the Fukushima Daiichi accident varied at the Member State level. The most marked decision was Germany's accelerated nuclear phase-out. Others paused nuclear as well, while Italy reaffirmed its moratorium in the 2011 referendum. Even in France, reducing the share of nuclear power was legislated in 2015. In many cases, phase-out plans or their reversal were closely tied to domestic governing coalitions. Over recent decades, for instance, Sweden has repeatedly shifted its nuclear policy. At the same time, the UK finalised the decision to construct Hinkley Point C in 2016.

At EU level, concerns over nuclear safety coincided with a broader shift towards an increasingly integrated energy and climate framework for 2030 and strengthened a growing focus on renewables and energy efficiency (Held et al., 2014). Persistent delays in new nuclear projects made apparent over the 2010s further consolidated this trend. The Clean Energy for All Europeans package (2018) further strengthened the policy architecture to advance renewable energy, energy efficiency, electricity market integration, and energy and climate governance through NECPs (EUI, 2020). During this period, nuclear remained one of the main sources of low-carbon electricity, but unlike renewables and energy efficiency, it was not associated with explicit EU-level targets or policy measures. The Governance Regulation (Regulation (EU) 2018/1999) did not provide for dedicated nuclear targets or specific reporting requirements. Nuclear's access to EU financial support remained limited. The European Investment Bank (EIB) maintained a generally restrictive stance on nuclear financing, mainly focusing on areas of safety upgrades, decommissioning, and research, while EU funding opportunities remained largely limited to Euratom programmes. Some recent positive policy developments are discussed in section 1.2.

The political contention surrounding nuclear energy increasingly manifested itself in the late 2010s. While the Euratom Treaty ensures that nuclear development cannot be blocked by other Member States, State aid approval for new nuclear projects became the main legal area for disputes among Member States (EUI, 2019; Hancher, 2019; Hancher and Salerno, 2021). In the *Austria v. Commission* cases (Case C-594/18 P and Case T-356/15), Austria challenged the Commission's approval of State aid for Hinkley Point C in the UK (an EU Member State at the time), but the General Court and the Court of Justice (CJEU) upheld the decision. The ECJ confirmed that nuclear energy constitutes a legitimate objective under the Euratom Treaty and that Member States retain broad discretion in defining their energy mix, subject to EU State aid rules. This reasoning was reaffirmed in the subsequent ECJ decision on Austria's challenge against Hungary's Paks II (Case T-101/18) in 2022, which likewise upheld the Commission's State aid approval[1].

Together, these rulings consolidated case law confirming Member State discretion over their energy mix choices, subject to EU State aid scrutiny. Yet, beyond Euratom provisions and secondary legislation, EU-level policy and regulatory frameworks remained reluctant to assign a more explicit role to nuclear energy in areas such as EU-level targets, funding instruments, or implementation mechanisms. As a result, by the launch of the European Green Deal in 2019, nuclear energy was largely treated as a legacy technology and a national policy choice, without a clearly articulated role in EU climate and energy governance, regulatory frameworks, or funding architecture.

1.2. FROM THE EUROPEAN GREEN DEAL TO THE CLEAN INDUSTRIAL DEAL

The 2019-2024 political cycle unfolded with high climate ambition under the European Green Deal, culminating in the objective to reach net zero by mid-century under the European Climate Law. Decarbonisation of the entire economy was at the centre, with a strong emphasis on energy supply, including the decarbonisation of power, industry, transport, and buildings. A set of legislative proposals under the Fit for 55 package aimed to align EU energy and climate legislation with these objectives.

Although net-zero pathways in principle accommodated nuclear as a low-carbon technology, and nuclear continued to feature in the Commission's long-term net-zero modelling, it happened primarily through the LTO of the existing fleet rather than

[1] In 2025, the CJEU (Case C-59/23 P) annulled the Commission's State aid decision. See the discussion in Hancher (2025).

assumptions of significant expansion. Its integration into EU policy debates also remained constrained by divergent Member States' positions and the institutional sensitivity of the prevailing policy mindset at the time. As a result, nuclear energy remained highly contested across multiple policy and legislative files.

A notable example was the classification of nuclear energy within the EU Taxonomy for sustainable activities (Taxonomy). The 2018 draft proposal and subsequent delegated acts triggered significant controversy and public debate about the potential inclusion of nuclear. (European Commission, 2020; EEB, 2022). This led to extensive technical assessments, including by the Joint Research Centre (JRC), and extended political negotiations (European Parliament, 2022). Nuclear was ultimately included under the Complementary Climate Delegated Act in March 2022, but under specific conditions and as a transitional activity. This was a fragile compromise that left unresolved political tensions among Member States, dissatisfaction among environmental NGOs (EEB, 2022; Henrich Böll Stiftung, 2022; E3G, 2022), and concerns about regulatory and investment certainty (Box 6).

In parallel, the role of nuclear-derived products emerged in discussions on the certification of renewable and low-carbon hydrogen, through the intensive debates on renewable fuels of non-biological origin (RFNBOs) during the revision of the Renewable Energy Directive (RED III) and the respective Delegated Act (2023/1184), and through the development of the Delegated Act on low-carbon hydrogen (2025/2359). Under the latter, nuclear power purchase agreements (PPAs) and associated Guarantees of Origin (GOs) have not been recognised as an eligible pathway to demonstrate compliance.

EU-level financing remained another contentious area. The EIB continued to maintain a generally restrictive approach to nuclear financing, largely reflecting divergent Member State preferences within its governing structure and a historically restrictive lending stance towards nuclear energy. Other EU funding instruments remained either restrictive or, at best, played only a limited and indirect role in supporting nuclear-related investments.

Political dynamics among Member States remained strongly polarised, with informal groupings at the Council, such as the Friends of Renewables and Nuclear Alliance, standing largely opposed, with few Member States bridging the divide. This contradictory framing of nuclear and renewables in opposition, despite their potentially complementary roles, was visible in practice, as Germany continued to rely on nuclear-based electricity imports from France while finalising its own nuclear phase-out. At the same time, political tensions persisted between Germany and France within the Council over nuclear energy (Lafrance and Wehrmann, 2023; Alipour, 2023; Von der Buchard, 2023).

The 2022 energy crisis marked a turning point. Rising energy prices in late 2021, exacerbated by the Russian invasion of Ukraine in 2022, brought affordability and energy security to the centre of the political agenda. The crisis also exposed the urgency of electricity market reform, among other objectives, to provide long-term predictability for low-carbon investments (2022-2024) (Gazzoletti et al., 2023a; 2023b). The eligibility of both newbuilds and the existing nuclear fleet for price stabilisation mechanisms, including CfDs, was the subject of intense debate during the legislative process, triggering politically sensitive negotiations. Ultimately, nuclear was made eligible under the revised EMD, including the existing plants, albeit under certain conditions (section 3.2).

At the same time, increasing concerns over industrial competitiveness and strategic dependencies began to reshape EU industrial policy. The Net-Zero Industry Act (NZIA) (Regulation (EU) 2024/1735), proposed in 2023, reflected the EU's response to increasing global competition in cleantech (Elkerbout et al., 2023). While the initial proposal placed greater emphasis on a defined category of 'strategic net-zero technologies', the final text adopted a more flexible approach, with greater focus on strategic net-zero projects and the development of manufacturing capacity. The NZIA recognised nuclear fission and fuel cycle technologies as part of the cleantech decarbonisation toolkit, marking a gradual shift towards viewing nuclear as part of a broader industrial competitiveness and strategic autonomy agenda. Growing interest in the potential role of nuclear energy in industrial clusters was further signalled by the 2023 Commission's declaration on SMRs and the launch of the SMR Industrial Alliance in 2024.

Gradually, a more positive tone took hold at the start of the 2024-2029 political cycle. The shift was signalled by the 2024 Nuclear Energy Summit in Brussels, the Franco-German nuclear rapprochement, that is, a political agreement between the two countries not to block nuclear energy, and explicit references to nuclear as a baseload in President von der Leyen's State of the Union in 2025.

These developments arguably reflect a broader reorientation of EU energy priorities, driven by energy security concerns, industrial competitiveness and the urgency to contain rising energy costs. These issues have been consistently reinforced across major EU policy documents, from the Draghi Report (2024) through the early initiatives of the second von der Leyen Commission, such as the Competitiveness Compass (2025), the Clean Industrial Deal (2025), and the Action Plan for Affordable Energy (2025). The EU climate framework for 2040 (Regulation (EU) 2026/667), which adopted the climate target for 2040 in 2026, has included nuclear energy among 'all zero- and low carbon energy solutions' needed to 'decarbonise the energy system with a technologically neutral approach'.

The EIB's new Energy Sector Orientation-Powering competitiveness, climate and strategic autonomy (2025) also points to a clearer shift: it explicitly refers to SMRs, advanced modular reactors (AMRs), the fuel cycle, and security of supply, placing nuclear within the set of technologies relevant to competitiveness, climate objectives, and strategic autonomy. Similarly, the Clean Energy Investment Strategy (2026) recognised EIB support for de-risking SMR-related investments in line with the EU's SMR Strategy (2026), and 'the associated fuel cycle facilities and supply chain', also through support under the InvestEU programme.

Recent EIB financing decisions confirm this gradual shift. In 2025, the EIB granted EUR 400 million[2] to Orano for the expansion of uranium enrichment capacity and EUR 90 million to Teollisuuden Voima Oyj (TVO) for upgrades at Olkiluoto 3 in Finland. These investments extend beyond the EIB's traditionally highly selective engagement with nuclear energy, indicating a broader involvement in the sector, especially where projects strengthen energy security and supply-chain resilience. The Clean Industrial Deal State Aid Framework (CISAF), adopted in June 2025, also reflected a broader approach to State aid for industrial decarbonisation, allowing support for a wider range of low-carbon technologies.

More recently, the Iran war in early 2026 has added more pressure. Reducing fossil fuel imports and scaling up 'homegrown energy' have become increasingly more politically attractive, but also necessary. Efforts to strengthen and 'Europeanise' value chains, in ongoing discussions on the draft Industrial Accelerator Act (2026), further demonstrate concerns over supply chain dependencies.

This evolving policy and market context has contributed to a gradual reassessment of nuclear energy strategies across Member States. Several Member States have subsequently reconsidered or partially reversed nuclear phase-out plans, while others, particularly those with high shares of coal-fired generation, are considering LTO and newbuild projects. These include, among others, Belgium, Bulgaria, Czechia, Estonia, France, Poland, Romania, Slovakia, and Sweden. Updated NECPs increasingly reflect this renewed interest (European Commission, 2025b). Even in Germany, where nuclear phase-out (2023) remains irreversible in practice, there is growing acknowledgement in political discourse of its strategic implications, with Chancellor Merz pointing to the nuclear phase-out as a strategic mistake.

The renewed political and strategic appeal of nuclear energy across Member States reflects a combination of factors, including its high value-added content and relatively sovereign supply chains (section 4.1). Whether this renewed interest will prove durable remains an open question. Nevertheless, unlike in the mid-2000s, current interest appears influenced less by short-term price signals, such as high oil and gas prices, and

[2] Other than in specifically-mentioned cases, all currency units are expressed in 2025 EUR terms.

more by structural drivers, including energy security, system integration challenges, cost-efficiency of the energy transition, and industrial competitiveness. Beyond decarbonisation objectives, the appeal of nuclear is increasingly driven by energy autonomy considerations, with the underlying narrative echoing that of the 1970s.

However, while level-playing field considerations between nuclear energy and other low-carbon technologies has gained increasing recognition in strategic documents in recent years, their practical application remains uneven, as further discussed in section 1.3. Ultimately, nuclear energy finds itself in a structurally ambivalent position. EU treaties reaffirm Member State sovereignty over the energy mix, a principle that the ECJ has repeatedly reaffirmed, and therefore nuclear energy cannot be prohibited at EU level. At the same time, EU-level policy is increasingly affecting the nuclear business case indirectly through the EMD, State aid, financing frameworks, and other regulations.

Because of persistently divisive Member State positions, reaching agreements on files that better accommodate nuclear energy may become increasingly challenging, and in some cases could remain in deadlock. While the notable shift in the debate observed in this political cycle should be welcomed, it is yet to be seen whether this reflects a move away from an ideological divide between low-carbon technologies towards a more functional reassessment of the respective roles of these technologies in a future energy system.

1.3. EU POLICY AND REGULATORY FRAMEWORKS – WHAT PLACE FOR NUCLEAR?

While political acknowledgement from EU leadership (e.g. by President Von der Leyen) signals a more open stance towards nuclear energy in this political cycle, this shift is yet to be fully translated into EU policy and regulatory frameworks. As discussed in sections 1.1 and 1.2, persistent divergences among Member States regarding the role of nuclear energy continue to constrain the development of a more coherent EU approach.

On one hand, nuclear energy can already contribute to the EU's climate neutrality objective under the European Climate Law, and the 2040 target has explicitly acknowledged nuclear as one of the options on par with other low-carbon technologies, based on the technology neutrality principle. On the other hand, the role of nuclear is only indirectly reflected through these economy-wide decarbonisation objectives. Unlike renewable energy and energy efficiency, nuclear energy is not supported by dedicated EU-wide deployment targets. While this understandably reflects the political realities of EU decision-making and Member State preferences, it has inevitably contributed to the views that nuclear energy does not enjoy the same level of policy visibility or strategic recognition as other low-carbon technologies.

The Governance Regulation is formally technology-neutral, and nuclear energy can be included by Member States in their NECPs. However, in practice, the NECP architecture remains structurally anchored in renewable energy targets under RED III, which feed into the Commission's gap-filling assessments. As a result, nuclear energy scenarios included in NECPs do not benefit from an equivalent EU-level target framework. Combined with the absence of a dedicated section on firm low-carbon capacity contributions in the Commission's NECP assessment template, this results in less systematic scrutiny and feedback on nuclear pathways. In addition, no equivalent cooperation mechanisms exist for nuclear energy, unlike those available for renewables, such as statistical transfers and joint projects under Articles 8-13 of RED III).

The forthcoming revision of the Governance Regulation may open further space for this debate, particularly if NECPs are expected to be strengthened as investment planning tools. Greater consistency in the treatment of all low-carbon technologies within NECPs would improve transparency and ensure that nuclear energy can be more effectively reflected in national and EU-level planning frameworks, even if dedicated EU-wide targets for nuclear remain politically unfeasible.

It is widely recognised that dedicated EU-level nuclear targets are likely to remain politically unfeasible. However, there is still scope to create space for a more coherent and technology-neutral framework that better accommodates Member States choosing to pursue nuclear energy alongside other low-carbon technologies. The ongoing debate on the post-2030 climate and energy framework provides an opportunity to reflect on how nuclear energy fits within a broader net-zero policy architecture, both at the generation level and across sector-coupling applications, such as hydrogen from net-zero energy sources and net-zero energy use in heating and transport.

The post-2030 energy framework could provide an opportunity to reconsider the role of nuclear energy and other low-carbon technologies, establishing concrete pathways for delivery in support of the 2040 climate target. At the same time, meeting ambitious electrification objectives in the coming decades may require a significant contribution from nuclear energy, which a forthcoming Electrification Plan could recognise through a more explicit technology-neutral approach to low-carbon generation.

The objective is therefore to ensure greater consistency in the treatment of nuclear energy and nuclear-derived products across existing EU legislation and policy instruments. This would provide greater regulatory predictability for a technology characterised by exceptionally long investment horizons, while preserving Member States' freedom to determine their own energy mix.

However, several persistent issues remain regarding what is often referred to as 'level-playing field' or regulatory neutrality. Others directly affect the business case for nuclear, thus raising broader questions about the role that nuclear energy can continue to play should the current regulatory approach remain unchanged.

Table 1 summarises examples of differentiated treatment of nuclear energy across EU policy and regulatory frameworks, addressed in greater detail throughout the report.

Table 1. EU policy and regulatory frameworks

Energy and climate targets and governance	EU climate framework is technology-neutral and allows nuclear contribution, but lacks dedicated nuclear targets, trajectories, or governance mechanisms comparable to renewables. ➔ Section 1.3
Market design and system planning	Wholesale market design and dynamics create revenue challenges, potentially leading to volatility and declining revenue adequacy. Nuclear's system value (firm low-carbon generation, adequacy, inertia) is not fully reflected in current market arrangements. ➔ Sections 2.1, 3.1, 3.2
Sustainable finance and taxonomy	Nuclear has obtained conditional recognition under the EU Taxonomy, but restrictions and uncertainty remain for long-term investment planning. ➔ Section 4.2
EU funding and de-risking	Nuclear support remains fragmented and mainly focused on R&D. Support is mainly channelled through Euratom, Horizon Europe (limited scope), and recently through selective access via InvestEU for SMRs, while major EU funding instruments largely exclude nuclear, and the EIB plays only a limited role, linked mainly to safety and lifetime extensions. No dedicated EU deployment framework exists for large-scale nuclear or FOAK projects. ➔ Section 4.2
State aid	Two-way CfDs have been harmonised at EU level in the latest EMD revision, yet nuclear projects remain subject to lengthy State aid assessments. IPCEIs are positive signs under the NZIA. Despite recent improvements with the CISAF recognising the role of nuclear in decarbonisation (and faster handling of some cases), approval timelines remain a key investor uncertainty factor.

	➔ Sections 3.2, 4.1.
Sectoral integration: hydrogen, fuels and heat	Recognition of nuclear-derived products across EU sectoral frameworks remains inconsistent. Nuclear-produced hydrogen, heat and transport fuels are not treated equivalently to renewable pathways. In particular, nuclear PPAs and associated GOs are not recognised under the low-carbon fuels methodology, while nuclear heat is not covered by binding EU targets or dedicated support mechanisms. Future demand-side instruments, including the Industrial Decarbonisation Bank, should ensure technology-neutral treatment of low-carbon pathways. ➔ Section 2.2
Industrial policy and supply chains	NZIA recognises nuclear as a net-zero technology, but nuclear manufacturing ecosystems receives less structured EU support than other clean technologies. Demand visibility, industrial coordination, and supply chain development remain key challenges. IPCEIs are likely to remain the core support instrument. More support from EU dedicated funding is needed. ➔ Section 4.1
SMRs	The EU's SMR Strategy (2026) signals growing political support, but deployment depends on solving financing, licensing, standardisation, supply chain, and demand uncertainty. The EUR 200 million support under the current InvestEU represents an important step forward. ➔ Section 5

2. NUCLEAR ENERGY IN A LOW-CARBON ENERGY SYSTEM

The general direction of energy system transformation in the EU is clear: electrification supplied by low-carbon electricity is the most efficient way to deliver energy services wherever feasible, complemented by low-carbon molecules through sector integration in hard-to-electrify sectors, including industrial feedstocks, high-temperature industrial processes, and certain fuels (Belmans and Glachant, 2025). Electrification is increasingly recognised as a core driver of competitiveness through higher end-use efficiency, functioning as an efficiency strategy.

Electrification rates are therefore expected to increase substantially, reversing decades of stagnation. From today's level of approximately 23%, the Clean Industrial Deal and the Affordable Energy Action Plan set a reference of 32% by 2030, with further elaboration expected in the forthcoming Electrification Action Plan. Projections suggest an increase to about 50% and 61% of low-carbon electricity in the final energy demand by 2040 and 2050, respectively (Eurelectric, 2024; Makaroff et al., 2025). Achieving these trajectories from the current plateau of around one quarter and keeping pace with other electrifying economies, and especially China[3], will require effective implementation measures to overcome limited progress over the past three decades.

Electrification is expected to expand as a central pathway for decarbonising transport, buildings, and industry, and to be further reinforced by the renewed urgency to reduce dependence on fossil fuel imports. Electricity demand from end-use sectors is therefore expected to increase, although its growth rate remains uncertain and will depend on technology choices, policy support, and system constraints. Reindustrialisation and the development of the digital economy would also require accommodating electricity demand profiles from continuous-load sectors (such as energy-intensive industries and digital infrastructure) into an increasingly complex low-carbon electricity system (CATF, 2026; Weidlich et al., 2026).

Although electrification remains the primary pathway, certain sectors will continue to require low-carbon molecules, particularly as industrial feedstock, for high-temperature industrial processes, and for applications where direct electrification remains difficult, such as maritime and aviation. In this context, low-carbon molecules are increasingly viewed as important elements of a more integrated energy system, increasingly reflecting the roles beyond conventional dispatchable generation towards a 'multi-vector approach' (Gorenstein Dedecca et al., 2025).

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[3] In China, electrification has more than doubled since 2005 and surpassed 27% in 2025 (IEA, 2026).

At present, expectations regarding the role and maturity of different technologies have evolved, with earlier assumptions of rapid and straightforward deployment giving way to a more complex and uncertain reality. For instance, expectations for hydrogen infrastructure and CCS have weakened, while renewable capacity expansion has generally accelerated, albeit with remaining constraints in some contexts due to permitting delays, supply chain bottlenecks, rising costs (particularly for offshore wind), and grid limitations. The future energy system will therefore depend on a combination of low-carbon technology choices, their economic viability, degree of commercial maturity, and enabling policy and regulatory frameworks.

These developments open space for nuclear energy to contribute to meeting higher electricity demand and supporting industrial activity in Europe through firm[4], low-carbon output, including for non-electric applications. This section analyses nuclear's role in the transforming energy system along two dimensions: section 2.1 analyses its interaction with increasing flexibility needs and its system-relevant characteristics, including contribution to adequacy, grid stability, and overall system costs; and section 2.2 assesses its potential in non-electric applications, including industrial heat, district heating, hydrogen/e-fuel production, and desalination, which represent additional roles for nuclear energy.

2.1. NUCLEAR ENERGY IN A TRANSFORMING ELECTRICITY SYSTEM

This section focuses on the core dimensions of nuclear's role in the evolving electricity system: the benefits and challenges of nuclear in a changing electricity system (section 2.1.1); baseload operation, which remains central to the system value provided by nuclear energy, and the scope for load-following options (section 2.1.2); nuclear's contribution to system adequacy (section 2.1.3); its role in grid stability services (section 2.1.4); and nuclear's impact on the overall system (section 2.1.5).

2.1.1. Electricity system transformations and the role of nuclear energy

The electricity system is undergoing substantial transformation. It is expected that a future EU electricity system will rely largely on variable renewable energy sources (vRES), whose strong uptake has been driven over recent decades by supportive policies and rapidly falling generation costs. However, increasing shares of vRES will need to be complemented by flexibility options, including low-carbon dispatchable[5] generation, to ensure system adequacy and reliability, therefore requiring significant system-level

[4] Firm power is the capacity or supply intended to be available at all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions (US EIA, n.d.).

[5] Dispatchable sources refer to those whose power output can be readily controlled (IEA, n.d.).

adjustments (Gorenstein Dedecca et al., 2025). Simultaneously, Member States face the challenge of reducing dependence on imported fossil fuels to strengthen security of supply. This combination of objectives has led to a range of potential solutions, each with distinct implications for system cost, reliability, and system complexity, while also highlighting the growing need for greater coordination and integration at the EU level.

In this context, the ongoing transformation towards a system increasingly based on vRES and decreasingly reliant on fossil fuel backup reinforces the need for low-carbon technologies, which are dispatchable at an individual asset level. These include geothermal, bioenergy, concentrated solar power[6], hydropower, and nuclear. However, as noted by the IEA (2022a), their role in the decarbonising energy system has so far been relatively underemphasised in policy and market frameworks, and they continue to face barriers to commercialisation and bankability (Spokas and Ricks, 2026).

Value of nuclear

Among low-carbon dispatchable technologies, nuclear energy enjoys certain characteristics that increasingly highlight its system value.

First, nuclear sources are broadly *geographically independent* and can provide large-scale generation in locations where other low-carbon dispatchable options may not be available (IEA, 2022b). Its deployment may still, however, be constrained by the availability of abundant water resources for cooling purposes, although the adoption of recirculation systems in cooling towers can mitigate this requirement.

Second, nuclear power plants have a *very high spatial power density*[7] compared with other generation sources, making them particularly valuable where land availability and spatial planning are important binding constraints.

Third, nuclear fuel has a *very high energy density*[8]. Low-volume fuel supplies contribute to energy security, also by further reducing dependence on imported lower-energy-density fossil fuels. While the fuel cycle is still[9] partially dependent on non-EU uranium

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[6] Concentrated solar power is dispatchable if combined with thermal storage.

[7] Spatial power density represents the magnitude of power generation per unit horizontal surface area requirement, expressed in W/m^2. Nuclear is positioned among the highest with ~240 W/m^2 compared to other technologies: natural gas (~480 W/m^2), solar PV (~7 W/m^2), wind (~2 W/m^2) and hydropower (~0.1 W/m^2) (van Zalk and Behrens, 2018).

[8] Energy density represents the extractable energy per unit volume/mass of fuel, expressed in Wh/kg or Wh/L. Nuclear fuel (uranium-235) has an extraordinarily high energy density (~24 000 000 kWh/kg). Compared to other conventional baseload fuels, coal has an energy density of ~8 kWh/kg, and natural gas has an energy density of ~15 kWh/kg (ENS, n.d.a).

[9] France is at the forefront of the advance towards a closed nuclear fuel cycle, aiming to fabricate new mixed oxide (MOX) fuel from recycled spent fuel. Closed fuel cycles in the EU remain very limited.

enrichment and global supply chains, exposure to price volatility and logistics risk remains significantly lower than for fossil fuels.

Fourth, nuclear provides *large-scale dispatchable low-carbon electricity supplies* at high capacity factors – typically 80-90% – over operational lifetimes of at least 60 years, with the possibility of LTO extensions for a further 10-20 years. From a system perspective, the dispatchability and high capacity factors of nuclear may complement the inherent variability, intermittency and lower-capacity factors of standalone vRES plants[10].

2.1.2. Nuclear in an increasingly flexibility-driven electricity system

Historically, nuclear power plants were designed to operate in baseload mode, which involves maintaining a constant power output – typically close to the power plant's rated power. However, this characteristic is becoming increasingly misaligned with electricity systems characterised by high shares of vRES and flexibility resources (Gorenstein Dedecca et al., 2025). As a result, nuclear energy is increasingly expected to move towards load-following operation – that is, modulating power output to adjust supply to residual demand needs.

In principle, modulation does not pose substantial technical constraints, as most reactor designs operating in the EU are technically capable of doing so. However, the greater need for modulation/flexibility fundamentally affects their operational and economic logic, whose system value is optimised under stable, high capacity factor baseload operation. This section discusses nuclear's ability and operational limitations to load-follow, while its economic and regulatory implications are discussed in section 3.2.

Baseload operation

Nuclear power plants in Europe have mostly operated in baseload profiles (Figure 2). Their power output variations had been broadly limited to frequency regulation for grid stability purposes[11] and plant shutdowns to refuel and sometimes make adaptations to comply with changing safety procedures (NEA, 2011). Operation at high load factors was possible because of the relatively low shares of generation originating from nuclear in power mixes at the time[12]. This allowed for an optimal revenue capture for plant operators, which

[10] In the EU, capacity factors for solar photovoltaic (PV) range from 2-14% with an average of 11%. Similarly, capacity factors for onshore wind ranges from 13-49%, with an average of 24%, and from 31-44% with an average of 39% for offshore wind. Values vary geographically depending on resource availability (Juge et al., 2026).

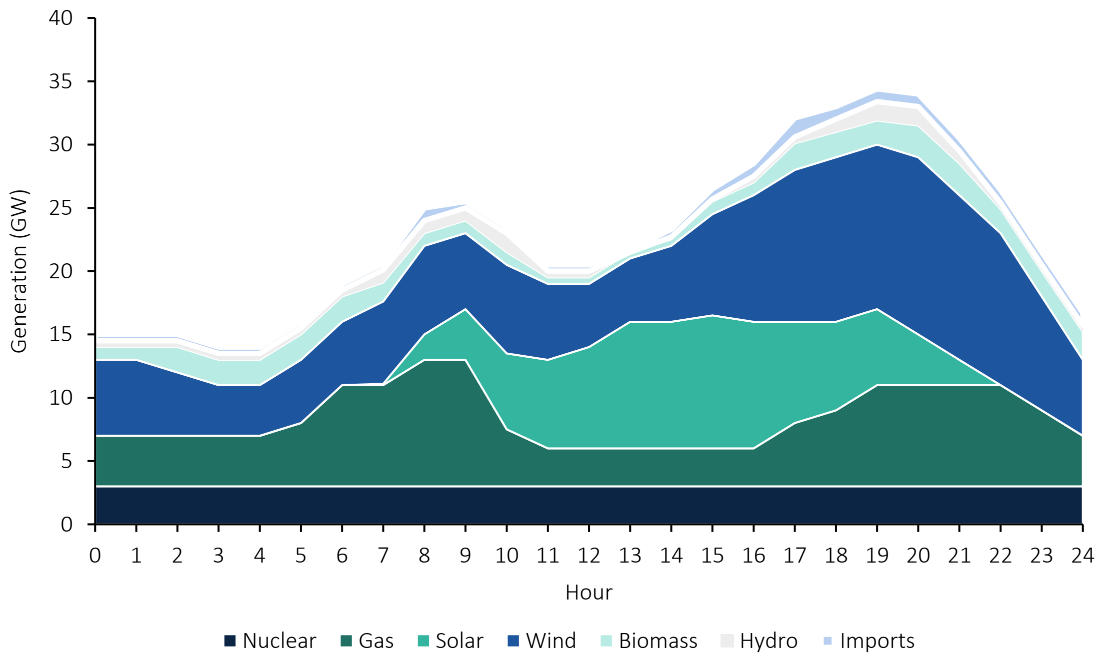
[11] Includes both primary and secondary frequency regulation. Primary frequency regulation involves short-term adjustments (in the scale of seconds) to stabilise power generation. Secondary frequency control involves longer-term adjustments (seconds-to-minutes) to address frequency deviations (Lynch et al., 2022).

[12] Greater shares of nuclear capacity require some assets to load-follow to align the total load from the nuclear fleet with total system electricity demand.

benefited from the economic nature of nuclear generation, that is, high fixed costs and low variable costs (NEI, 2025).

Globally, average load factors from nuclear power plants stood at 82.2% in 2024 (IAEA, 2026a). This varies both annually and on an individual plant basis. While load factors between 70-90% are typical, some reactors have achieved annual load factors as high as 99.6%, for example, Romania's Cernavodă-1 and Germany's Gorhnde in 1996 and 1997, respectively. Achieving plant load factors above 90% significantly contributes to ensuring nuclear's economic performance and aligns its high capital intensity with its system value, characterised by high energy density and large volumes of low-carbon electricity supplied over long, stable operating periods.

Figure 2. Power system generation profile with nuclear units operating in baseload mode



Note: this is indicative of a typical generation profile and not representative of any specific energy system.

Load-following operation

Although baseload operation has been the default mode for nuclear power in Europe, nuclear power plants can also be operated in load-following mode, running below their rated capacities (Figure 3).

Load-following operation is classified in terms of frequency and planning. *Frequent load-following* occurs over a small range of the rated power (known as light cycles), and *less frequent load-following* occurs over a broader range of the rated power (known as deep cycles) (IAEA, 2018). *Planned load-following* refers to the programmed changes in power output which enable an initial balancing of the electricity supply and demand based on predictions. These are established days or even weeks in advance and face no additional costs, although optimising the schedules for planned load-following is a prerequisite for cost-efficient operation under higher future shares of vRES in the grid (Lynch et al., 2022; Loisel et al., 2018). In opposition, *unplanned load-following* takes place at the request of transmission and system operators (TSOs) to meet specific balancing requirements. This type of operation may be issued up to several minutes in advance, and therefore incurs additional costs[13], mainly because of fuel costs, which may see an increased associated cost of up to 34% (Persson et al., 2012). Planned load-following is the most common form of load-following operation in nuclear power plants.

The reasons for increased load-following requirements for nuclear vary.

First, this may be required in systems with nuclear's dominant presence in the generation mix, requiring matching the generation to the demand, as is the case with France[14] (Loisel et al., 2018).

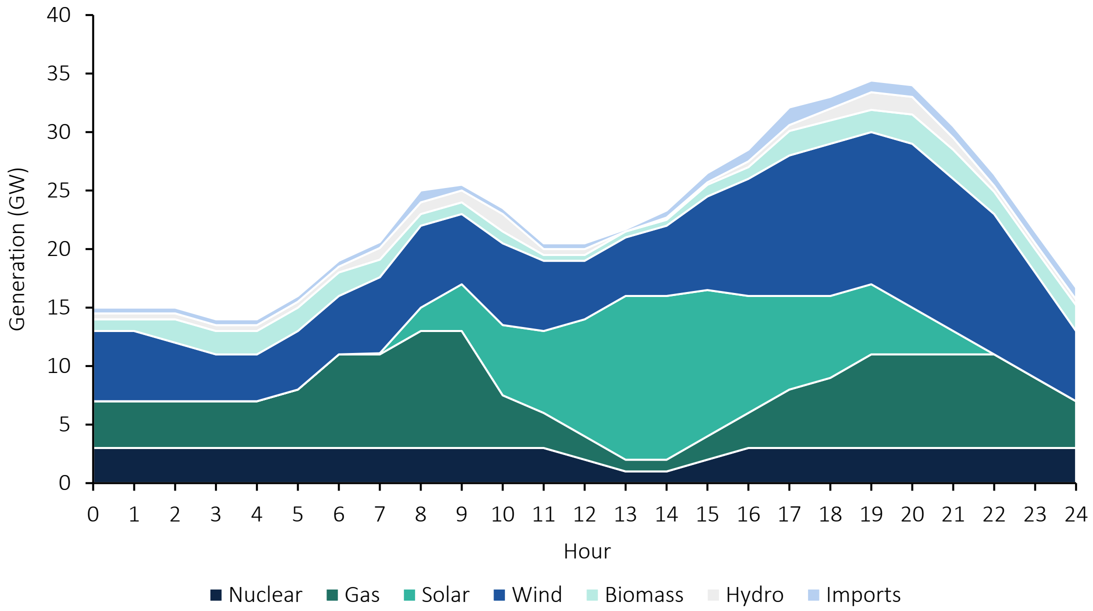
Second, more recently, growing shares of power generation from vRES can significantly affect the generation profiles and dispatch of nuclear power plants under the current EMD (section 3.2). This has already been experienced in some Member States, including in Germany before their nuclear phase-out. In Spain, some nuclear power plants have already faced non-dispatch in certain periods when baseload generation has been covered by lower-marginal-cost hydropower plants.

Finally, greater cross-border interconnection capacities can pose a further challenge to market-driven dispatch, specifically under circumstances when sufficient volumes of lower-marginal-cost electricity are imported from a neighbouring bidding zone.

[13] The additional cost for boiling water reactors (BWRs) ranges 1-5% more, and for pressurised water reactors (PWRs) ranges 4-7% more (Persson et al., 2012).

[14] France's electricity system has the highest share of generation from nuclear sources globally. In 2024, nuclear power plants generated 67.3% total electricity. In 2005, peak generation was achieved, accounting for 78.3% of total generation (WNISR, 2021).

Figure 3. Power system generation profile with nuclear units operating in load-following mode



Note: power generation from nuclear undergoes planned load-following from 11h to 16h to integrate the growth in solar power generation. This is indicative of a typical generation profile and not representative of any specific energy system.

Technically, modern nuclear power plants offer high manoeuvrability, allowing for load-following operation. With the partial exception of the CANDU HWRs in Romania, whose design is optimised for stable output, almost all other designs deployed in the EU can run flexibly (i.e. in load-following mode).

Light water reactors (LWRs) – Europe's most common reactor type – are capable, by design, of operating in load-following mode with a ramping rate of up to 5% per minute, offering up to two daily power level changes between 100% and 50% of the plant's rated power (NEA, 2011). The manoeuvrability of Gen III/III+ reactors (including advanced LWRs) in Europe is regulated by the European Utilities Requirements (EUR), which, since 2001, enforces newly deployed reactors to be capable of undergoing daily load cycling between 50-100% of their rated power (but never below the 50% threshold) at a changing power output rate of 3-5% per minute. The number of cycles is limited to 2 operations per day, 5 per week, and 200 per year (NEA, 2011; Loisel et al., 2018). Older generation reactors, which were not originally designed to undergo flexible operation, may be retrofitted to do so, although requiring additional investment, particularly in instrumentation and control (I&C). This would allow their licensing to undertake load-following operation mode (Lokhov, 2011).

From a technical perspective and considering that younger nuclear units are specifically designed to operate flexibly, these do not bear significant impacts in doing so. Although exhibiting the possibility of flexible operation, the extent to which GW-scale LWRs can load-follow is limited by the possibility of pellet-cladding interaction (PCI) occurring and by the presence of xenon transients, which may restrict the ramping rate and decrease the fuel's fission reaction rate, respectively[15] (Lynch et al., 2022). Nevertheless, some technical incidents may be encountered in the core physics of reactors, particularly fatigue induced by mechanical or thermal stress. Over time, this can lead to component wear, particularly in the valves.

Load-following operation also appears to have only a limited effect on the ageing of reactors (IAEA, 2018; Lokhov, 2011; Lynch et al., 2022). However, additional operating costs relating to intensified monitoring and maintenance may be incurred. EDF has recently quantified maintenance costs derived from modulation at EUR 310 million/year for its nuclear fleet in France, representing 0.86 EUR/MWh[16] nuclear output.

Like GW-scale reactors, SMRs hold the prospect of providing flexibility in high-vRES power systems. In theory, these offer an even greater potential, as their smaller thermal mass allows for faster power ramping rates – up to 12% per minute compared with GW-scale LWRs' 1-5% per minute (Nøland et al., 2025). Their modular nature allows for individual unit ramping, providing even greater ancillary service[17] contribution to the grid (Gaster, 2025). In addition, if geographically distributed (as opposed to centralised GW-scale reactors), SMRs could offer greater responsiveness to local demand variations or renewable power output variability, avoiding transmission congestion and losses (Rolland et al., 2021; Crawforth et al., 2025). While SMRs could improve the overall reliability of power systems, their contribution is yet to be proved.

Although load-following is technically feasible in most cases, in practice, its use depends on national regulatory frameworks and system needs rather than technical limitations. Therefore, baseload operation reflects regulatory choices and economic optimisation, rather than hardware constraints. France's high share of nuclear capacity necessitates load-following operation in its units. In most other cases, however, nuclear units operate almost entirely in baseload mode. In Sweden and Finland, output modulation (as a result

[15] This mostly applies to the existing fleet of LWRs. Alternative designs, e.g. fast neutron reactors (FNRs) (advanced Gen IV designs), do not have issues related to xenon transients. These reactors would ease load-following operation.

[16] Other than in specifically mentioned cases, all generation and power plant capacities, expressed in watt-hour (Wh) and watts (W) in the report, are expressed in watt-hour-electric (Whe) and watt-electric (We) terms. Cases citing watt-hour-thermal (Wth) and watt-thermal (Wt) units are exceptions – representing thermal generation and capacity, respectively.

[17] Ancillary services are support services that help electricity grids operate reliably and safely, beyond generation and electricity delivery.

of load-following operation) is performed by hydropower units. Similarly, Czechia and Slovakia do not experience system needs for load-following nuclear power plant operation.

It remains to be seen how increasing shares of vRES will affect nuclear dispatch across Member States (section 3.2). Furthermore, the expansion of cross-border interconnection capacity could further affect the operation of nuclear power plants. In this context, surplus vRES generation in a neighbouring bidding zone could be exported more efficiently to adjacent markets, thereby exerting additional downward pressure on nuclear load factors and, consequently, revenues in export markets that include nuclear generation assets. At the same time, rising electricity demand is expected to shift the demand curve, which may help preserve a role for nuclear generation in a highly interconnected, high-vRES system.

2.1.3. Dispatchability and contribution to system adequacy

System adequacy refers to the ability of the power system to meet demand at all times, including peak demand and extreme conditions. It encompasses not only generation adequacy but also transmission constraints, contingency reserves, and the variability of renewable generation. In probabilistic planning terms, adequacy is commonly assessed using the loss of load expectation (LOLE) indicator, which statistically estimates the number of expected days per year when a system's demand cannot be met by its generation capacity. Reliability standards are often expressed at frequency occurrence levels, for example, 1 day in 10 years.

As the share of generation from vRES increases, maintaining adequacy becomes increasingly challenging, particularly during periods of generation stress, for example, during simultaneous low solar PV and wind power generation – commonly referred to as '*dunkelflaute*' events. In this regard, system adequacy is increasingly considered the binding constraint of the power system. While battery energy storage systems (BESS) coupled to vRES plants in hybrid setups can alleviate these impacts, their current limited grid-level adoption and short-duration storage (<8 hours) make high-vRES system operation challenging. In addition, significant expansion and upgrades to the grid would be necessary to operate high-vRES systems reliably.

As part of the European Resource Adequacy Assessment (ERAA), ENTSO-E (2025a) projects that regional power systems will become increasingly unreliable through to 2035 (although with substantial geographical variability), with the magnitude and expected range of LOLE values escalating throughout Europe. Within this framework, firm capacity plays a central role, as it reduces the likelihood of supply shortages. In addition, dispatchability is an essential element in strengthening the electricity security of supply, particularly in covering hours of peak demand and system stress. Nuclear power plants provide high availability and a high outage-adjusted capacity credit[18], because of their predictable and relatively low forced outage rates, which thereby lower the risk of load-shedding and extreme power-scarcity events.

Cross-border interconnectors also play an important role in adequacy provision by enabling the smoothing of generation profile variability across regions[19]. However, their effectiveness depends on correlated resource conditions and simultaneous stress events across interconnected systems, which can limit their contribution during extreme scarcity periods. One of the central priorities in the European Grids Package is strengthening cross-border interconnections. While this is expected to bring benefits, it also raises concerns among some countries about greater exposure to neighbouring electricity systems with insufficient low-carbon dispatchable capacity, grid constraints, and higher wholesale price volatility.

2.1.4. Grid stability provisions

Maintaining sufficient inertia in the grid is vital for power system operation. In Europe, power grids operate at a constant frequency of 50 Hz. Any major fluctuations below 49 Hz and above 51 Hz can result in load shedding, with impacts becoming increasingly significant at frequencies under 47.5 Hz or over 51.5 Hz – jeopardising the stability of grids and increasing the likelihood of power outages[20] (Omont et al., 2025).

The provision of inertia must not only be assessed as a physical property in grids, but as a strategic component critical to the reliability of the future of energy systems. Keeping a high-inertia reserve throughout the grid is fundamental to securing stable frequency, and thus grid reliability, and mitigating the impact of frequency disturbances.

High-inertia systems hold the ability to control deviations to a greater extent, slowing down the rate of change of frequency (RoCoF) (ENTSO-E, 2020). Lower-inertia systems, which hold a faster RoCoF, become vulnerable to more pronounced, rapid frequency fluctuations and susceptible to deeper frequency nadirs[21]. This may result in under-frequency load shedding, equipment disconnections, and ultimately, cascading power

[18] Capacity credit measures the extent to which installed capacity can be relied on during system stress conditions. Typical values place nuclear and gas at around 90-95%, while wind and solar contribute significantly less (often in the range of 5-20% and 0-10% respectively, depending on system conditions and penetration levels).

[19] The EU has set a target of upscaling transnational interconnecting capacity to 15% by 2030.

[20] Network code conform generation establishes frequency ranges within the 47.5-51.5 Hz range. The extent to which national energy systems' frequency can withstand deviations away from 50 Hz (while remaining within the stated range) is, however, system-specific and varies geographically (ENTSO-E, 2021).

[21] Frequency nadir is the trough (minimum) in frequency oscillation reached following power disturbances.

outages (Harvey, 2020; Dorileo et al., 2025). The current framework does not mandate a harmonised EU-wide requirement for minimum inertia level across Member States, although ENTSO-E sets a minimum inertia target of 2s to be achieved in continental Europe by 2035 (ENTSO-E, 2025b). It is therefore the TSOs' and national system regulators' responsibility to ensure system stability in their respective jurisdictions[22].

Traditionally, inertia has been provided by the rotating masses of synchronous generators coupled to the grid (including nuclear generators), which deliver an immediate physical response in the event of sudden frequency deviations resulting from an imbalance between power generation and load. These act as initial shock absorbers, which counteract and attenuate the effects of stability disturbances, buying time for grid operators to activate primary frequency response (PFR) mechanisms to restore system stability (Dorileo et al., 2025; NREL, 2020).

Table 2 showcases the Inertia Constant (H) of grids, that is, the ability to resist frequency disturbances of the H values (expressed in seconds) of different power generation systems. Synchronous thermal low-carbon generation, including nuclear, provides inertia at the asset level. While GW-scale nuclear reactors have the highest H values and have been the conventional form by which nuclear has provided inertia to the system, SMRs, if deployed at scale – which is yet to be demonstrated (section 5) – have the potential to offer fast frequency support with an improved response compared with centralised GW-scale plants. SMRs could reduce peak frequency oscillations by up to 14% and increase RoCoF by 21% (Dorileo et al., 2025), reducing the need for frequency reserves (Boudot et al., 2022). This has been especially recognised in the case of microgrids and standalone power systems.

Table 2. The inertia constant (H) of different sources of power generation

Electric Generation Technology	Mean Inertia Constant, H (seconds)
Nuclear	5.9
Coal	3.8-4.2
Gas	4.2
Geothermal	3.5
Hydro	2.7-3.5
Biomass	3.3

[22] For example, Ireland's TSO became the first to set a minimum kinetic energy requirement (i.e. synchronous generation) in its calculations to ensure system stability (Sánchez Jiménez et al., 2021).

Wind	0
Solar PV	0

Source: ENTSO-E (2020).
Note: hydro's range is attributed to its different source types (pumped storage, reservoir, run-of-river). Coal's range is attributed to different coal fuels (brown coal/lignite and hard coal).

The transformation of Europe's power mix towards a growing share of non-synchronous, inverter-based renewable generation[23], often located in remote areas, and a reduced presence of synchronous generation from thermal power plants, necessitate solutions for how future grids will retain sufficient system inertia. Box 1 provides an example of Great Britain, where inertia costs have increased in recent years.

One of the available options is imports via high-voltage direct current (HVDC) interconnections. These are increasingly viewed as an option for providing additional inertia by enabling fast frequency response (FFR) and power balancing between regions, acting as a stabilising agent in low-inertia systems, and reducing the risk of frequency droops (Ahmed et al., 2023; Mehigan et al., 2020). While some Member States increasingly rely on interconnections for inertia provision (Elia Group, 2026), current shortfalls in the interconnectivity between some systems may limit this possibility across the EU, highlighting the importance of ensuring sufficient physical inertia. The ongoing expansion of its interconnection capacity between neighbouring power systems in the EU is to be further reinforced through the negotiated European Grids Package, but many interrelated issues need to be addressed before it becomes a well-functioning option.

Additionally, non-generation inertia providers can emulate the ancillary services provided by synchronous generators (Box 2).

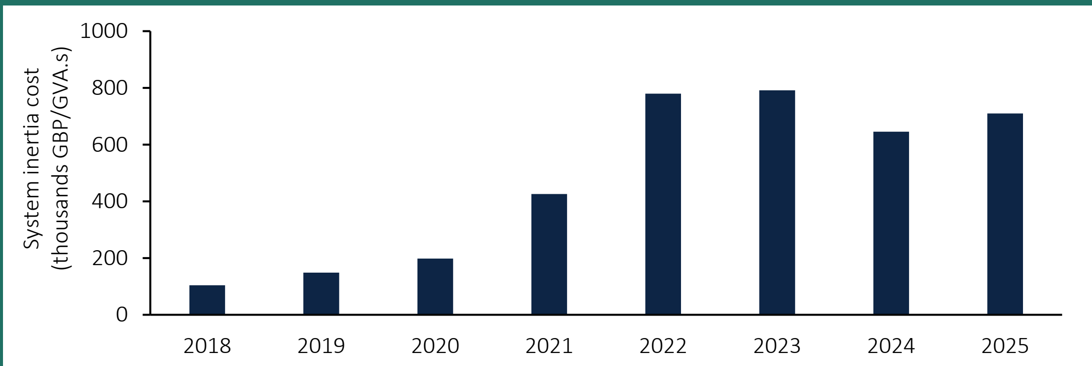
The commercialisation and deployment of these novel solutions need to be accelerated to match the deployment of inverter-based vRES across the EU. If this is not addressed, the grid risks becoming increasingly vulnerable.

[23] Most renewable energy sources (RES) being deployed in Europe lack the large rotating masses that offer inherent inertia. Hydroelectric power and geothermal sources do provide inertia, but their ability to provide widespread inertia is highly limited by geography (subject to availability). Wind turbines, which do involve rotating turbines, are only indirectly connected to the grid through frequency converters and so are unable to provide the necessary inertia.

Box 1. Inertia costs in Great Britain

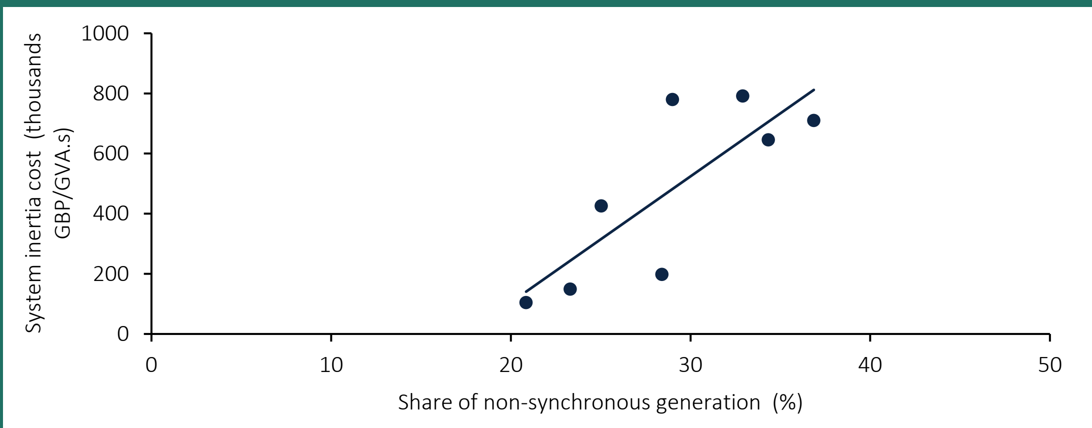
In Great Britain, the cost of maintaining system inertia has shown a clear upward trend in recent years. Figures 4 and 5 illustrate these trends, expressed in GBP/GVA.s, a metric indicative of costs per unit inertia shortfall. Not only has the frequency of events requiring inertia providers to participate in the balancing markets increased, but the associated costs have also risen significantly (NESO, 2026).

Figure 4. Annual system inertia cost in Great Britain.



Source: authors' composition. Data from NESO (2026).

Figure 5. Annual system inertia costs in Great Britain as a function of annual non-synchronous generation (wind and solar PV).



Source: authors' composition. Data from NESO (2026) and DESNZ (2026).

This development raises important questions regarding the economic implications of insufficient online inertia providers, particularly as it may necessitate maintaining additional capacity offline to ensure system stability. Similar challenges are likely to emerge across other European power systems.

From the current economic perspective, the EU's regulatory framework does not incentivise the provision of inertia, either from synchronous generators or from synthetic origin. Without specific remuneration or regulation for this ancillary service, inertia provision may be under-incentivised, and so grids may run the risk of becoming unable to contain future frequency deviations. From a nuclear perspective, its provision of inertia at asset level and growing contribution to pan-EU grid stability, particularly via the French nuclear fleet, raises open questions regarding future remuneration frameworks.

Box 2. Non-generation inertia providers

Synchronous condensers are spinning, voltage-controlling devices that maintain frequency synchronism with the grid. Despite being connected in phase-lock to the grid, these do not provide active power flows (i.e. no generation), but can contribute to the total inertia, although rather low (1s) compared with the higher inertia offered by nuclear generators (Kundur, 1994; Sauhauts et al., 2020; NREL, 2020).

Flywheels are devices that absorb excess electrical energy from the grid and store it as rotational energy. These can be coupled to synchronous condensers to provide further angular stability, improving the overall inertia constant. The deployment of synchronous condensers across the EU remains scarce, although there is a growing market across Member States, which is ramping up their implementation in light of growing requirements for inertia (ENTSO-E, 2025c).

Grid-forming inverters (GFMs), as opposed to grid-following inverters, use power electronics to mimic the behaviour of synchronous assets by actively regulating voltage and frequency, providing synthetic inertia (Mohammed et al., 2024). Grid-forming inverters can be coupled to inverter-based renewables (e.g. wind and PV) and BESS. When coupled to BESS, these offer black start capabilities. GFMs can provide FFR, a more rapid response than conventional PFR, which offsets the impact of high RoCoF events (NREL, 2020). While GFMs are commercially available, they remain limited to specific markets, e.g. micro-grids and islanded grids, and are not widely available at scale for utility-scale uptake, thereby hampering their full potential (Khan et al., 2024), although Australia is already advancing towards utility-scale deployment.

Additional devices, including *supercapacitors*, *virtual synchronous machines (VSMs)* and *adaptive hybrid inertia controllers,* can further contribute to frequency stability in renewable-dominated systems, but are, like the above, not currently available for system-wide adoption. Further investment, research and development (R&D) is required.

2.1.5. Nuclear's impacts on total system costs

With energy costs taking centre stage in the current political cycle, more attention is being given to broader system costs beyond the focus on plant-level costs. The LCOE, the standard metric for assessing the techno-economic performance of different power generation plants (section 3.1), shows that the generation costs of vRES have fallen substantially over the past two decades, while their near-zero marginal costs often reduce wholesale electricity prices during periods of high renewable generation. However, the LCOE metric itself does not adequately reflect the broader economic implications of various generation technologies at the system level, and therefore the final electricity price paid by consumers (Hirth et al., 2016; Ueckerdt et. al, 2013). Better accounting for the integration costs of vRES and total system costs (Box 3) has therefore gained increasing attention. The Affordable Energy Action Plan (2025) further underlined the importance of adopting a total system cost perspective for delivering electricity to consumers at the lowest possible cost.

Box 3. Total system costs

'Total system costs' are defined as the total economic costs of satisfying a given electricity demand at any given time, accounting for both electricity generation costs (i.e. in LCOE) and the additional costs encountered in delivering power to consumers. This encompasses plant-level costs as well as expenditures related to ensuring adequate reserve capacity and expanding network infrastructure (i.e. transmission and distribution), which is adapted to the evolving generation mix (Samark-Roth et al., 2025). All capacity additions to the energy mix, regardless of technology, entail additional costs beyond the direct deployment and operation of the power plant and are ultimately passed on to energy consumers through transmission and distribution charges in energy bills.

Additional costs contributing to total system costs can be classified by (i) profile costs, (ii) balancing costs, (iii) ancillary service costs, (iv) grid integration costs, and (v) flexibility costs (Lazard, 2025; NEA, 2024a; Samark-Roth et al, 2025). Figure 6 provides an overview of the components typically included in these.

(i) *Profile costs* are derived from the need to guarantee back-up or flexible capacity at periods in which demand cannot be satisfied by insufficient vRES generation.

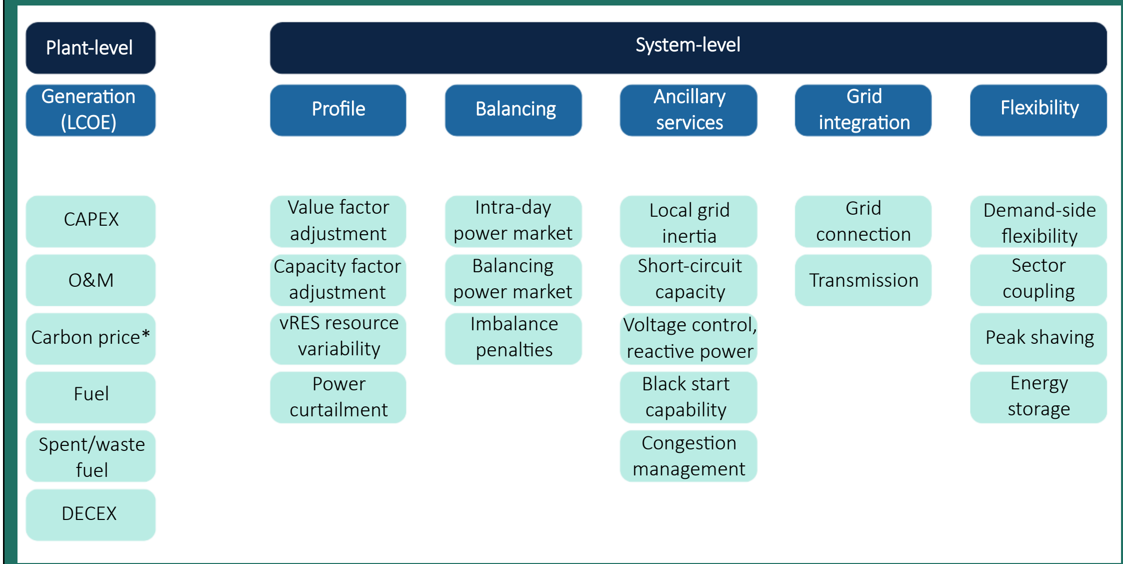
(ii) *Balancing costs* arise from the need to ensure system stability in cases of power generation uncertainty or forecast errors.

(iii) *Ancillary service costs* stem from the need to provide sufficient grid services, such as frequency regulation, voltage control or inertia to the grid, to guarantee its adequacy.

(iv) *Grid integration costs* are connection costs when connecting a power plant to the closest grid connection point, and grid upgrade costs necessary to incorporate power generation plants because of their capacity size or location.

(v) *Flexibility costs* are derived from the need for mechanisms to adjust generation and demand in electricity systems.

Figure 6. Examples of cost considerations accounted for in total system costs, including plant-level and non-generation system-level costs



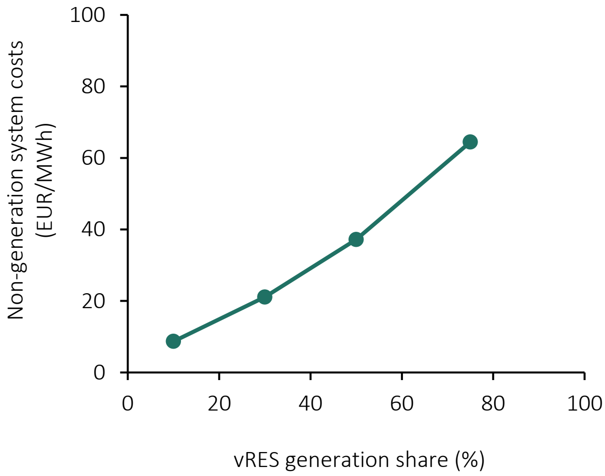
Source: authors' adaptation from Samark-Roth et al. (2025).
Note: *carbon price may not apply to all technologies.

Total system costs associated with adding capacity to the mix can vary with technology-specific characteristics. For instance, adding base-load units (i.e., nuclear, coal-fired, and combined-cycle gas turbine (CCGT) power plants) involves additional costs primarily related to maintaining reserve capacity necessary to balance the system at times of plant inoperability – either planned or unplanned. Integrating vRES – wind and solar PV capacity – typically requires substantially higher investment to maintain system adequacy because of their lower capacity factors, variable generation profiles, and geographically dispersed (decentralised) deployment often far from demand centres.

Figure *7* quantifies the share of additional system costs (other than generation costs) that are encountered when operating a power generation system at different shares of vRES.

A positive, non-linear correlation is modelled between the share of vRES capacity in the system and the total system costs. As the former increases, the latter becomes increasingly significant as a proportion of the overall costs. The additional system costs, added to the plant-level generation costs, provide a more accurate representation of the overall system costs in vRES-dominated systems.

Figure 7. Additional system costs at varying shares of vRES generation



Source: authors' composition using data from NEA (2024a).
Note: these only consider profile, connection, balancing and grid costs. Additional cost considerations, such as curtailment and ancillary service costs, are not included. To determine total system costs, the presented values (EUR/MWh_{vRES}) must be added to the generation costs.

Energy system modelling studies examining the impact of nuclear energy on total system costs report widely varying results, ranging from a 37.8% reduction to a 46.5% increase in annual system costs (Moen et al., 2025). These differences depend on the scenarios analysed, the share of nuclear energy in the system, and the underlying modelling assumptions.

The literature shows that nuclear energy can reduce total system costs by lowering the need for investments in energy storage and grid expansion. However, system costs can also increase due to uncertainties surrounding future nuclear investments and the high plant-level costs associated with nuclear. Generally, model outputs emphasise the importance of retaining existing nuclear capacity (in the form of LTO) within the energy mix to avoid total system cost escalation. In addition, potential total system cost reductions could be achieved by reaching certain shares of nuclear capacity, representative of nuclear newbuilds.

2.2. Non-electric value of nuclear energy

Beyond electricity generation, nuclear power plants can contribute to broader system integration through the provision of heat and low-carbon molecules, wherever electrification may not be feasible. These include certain industrial applications, such as high-temperature heat production and feedstocks, and fuels in sectors such as maritime transport or aviation. This section discusses whether and to what extent nuclear energy may provide value beyond electricity generation through cogeneration for district heating and industrial heat (section 2.2.1); hydrogen and electrofuels production (section 2.2.2); and desalination (section 2.2.3).

2.2.1. Cogeneration

The rationale for nuclear cogeneration lies in improving the relatively low efficiency of electricity-only thermal power generation – about 30-40% of thermal energy converted into electricity under the Rankine Cycle[24]. Combined heat and power (CHP) system adoption improves overall fuel utilisation and can improve the overall plant efficiency up to 80%[25] (Lipka and Rajeski, 2020), while providing low-carbon heat and improving plant economics.

Despite these benefits, nuclear cogeneration remains limited. Only 16% of the current global fleet – 67 out of the 409 operable reactors (representative of 26.3 TWt) – are used for non-electric applications (WNISR, 2026a). As of 2024, 94% of these were used for district heating, and only 4% for industrial process heat and 2% for desalination (IAEA, 2025).

Several factors explain this limited deployment. First, most existing reactors are LWRs, which operate at relatively low outlet temperatures – up to approximately 300°C, with their thermodynamic cycle adapted primarily to power generation purposes. As a result, they are unsuitable for many high-temperature industrial processes, such as steel, cement, and chemical processes. Second, cogeneration requires the close proximate location of the power plant to the urban or industrial demand centres, whereas nuclear plants are often located distant from these, making heat transport unviable. Finally, the economics of heat generation are often less attractive than those of electricity generation, as heat provision accesses only local, smaller-scale and more restricted markets. The

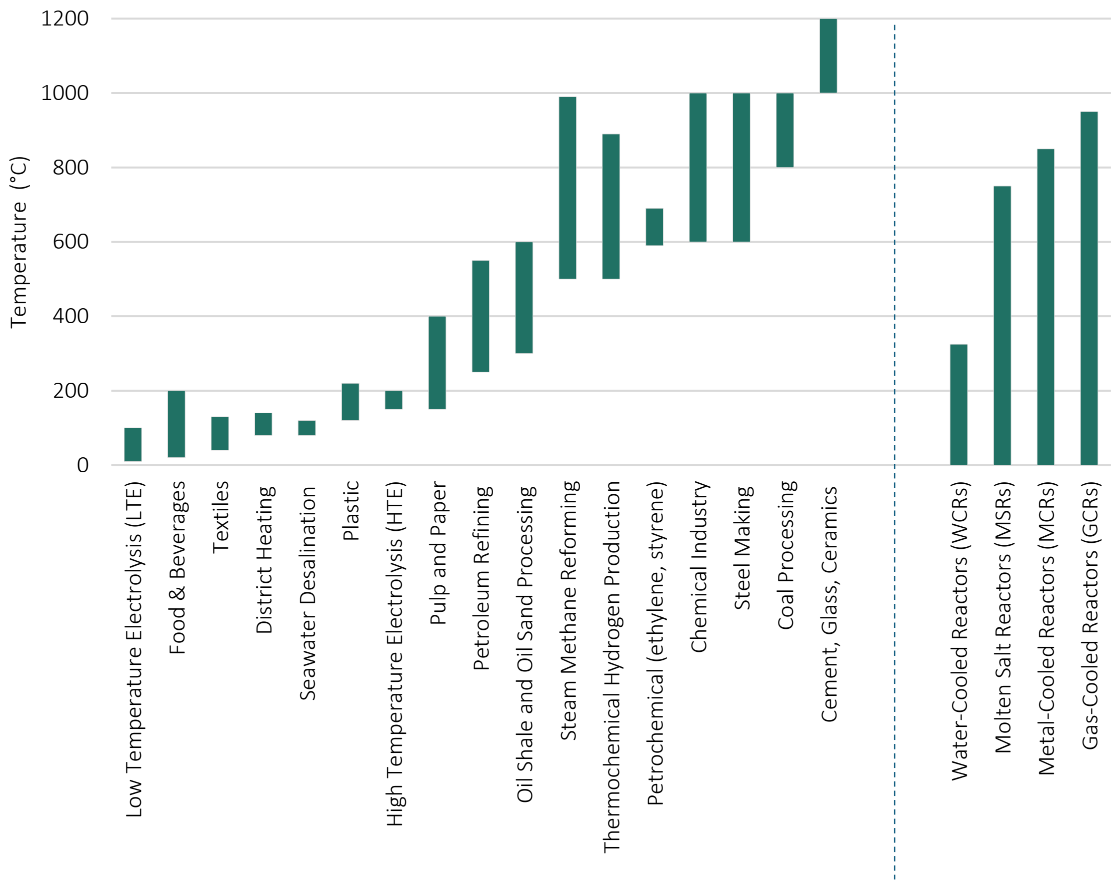
[24] All thermal power plants (e.g., biomass-fired, coal-fired, oil-fired power plants, and nuclear power plants) operate under the Rankine Cycle, all possessing relatively low power conversion efficiencies, ca. 30-40%. Therefore, these alternatives for baseload generation operate at similar efficiencies. Only CCGT, which combines the Brayton Cycle as the topping cycle and the Rankine Cycle as the bottoming cycle, achieves higher overall power conversion efficiencies, ca. 60% (Hasan et al., 2014).

[25] Final plant efficiency is dependent on several factors, including power-to-heat ratio.

demands for electricity and heat are also largely misaligned, resulting in heat generation being subordinated to electricity production in the absence of thermal storage facilities.

The contribution to cogeneration that nuclear can make, therefore, depends on the (i) reactor technology and its outlet temperature and the (ii) end-use temperature requirements (Figure 8).

Figure 8. Temperature requirements of end-use applications and reactor family core outlet temperatures



Source: authors' composition. Data from Castagnola et al. (2024), Locatelli and Mancini (2010), Hyer et al. (2023), and Sun et al. (2026). Datasets available in the Supplementary Information.
Note: out of all reactor families, only water-cooled reactors (WCRs) are a proven design deployed at scale. Reactor core outlet temperatures are representative of maximum temperatures and are not fully representative of the temperature received by the end consumer (i.e. inferior). These depend on the temperature of the extracted heat leaving the heat exchangers.

Currently, nuclear energy plays only a limited role in cogeneration in the EU, despite the heating and cooling sector accounting for around 50% of the final energy demand, with buildings representing approximately 60-65% and industrial heat roughly 30-40% of this demand. In the industrial sector, industrial heat accounts for around 74% of total energy use (Eurostat, 2023; IEA SHC, 2020). Largely because of the factors discussed above, only a few reactors provide CHP for district heating of nearby cities and some industrial users.

The policy framework for nuclear-based heat also remains mixed. The revised RED III (EU/2023/2413) provides the core framework for heat decarbonisation in the EU, but heat derived from nuclear energy does not count towards its renewable heating and cooling targets. The Energy Efficiency Directive (EED) (EU/2023/1791) adopts high-efficiency cogeneration as a technologically neutral concept to promote the simultaneous production of electricity and heat to improve overall plants' efficiency. Nuclear cogeneration is not excluded and can qualify if it meets primary energy savings criteria, while the core incentives are relatively minor for nuclear, and the support schemes were initially oriented towards fossil-based and smaller-scale CHP.

Overall, the potential contribution of nuclear-based heat is structurally larger than its current deployment suggests, but it remains strongly contingent on reactor design, plant siting and proximity to demand centres, and appropriate policy conditions.

District heating

For district heating, rejected heat from the primary cycle is recovered through a secondary cycle via a heat exchanger and distributed for heating purposes. An important advantage of nuclear heat is that it is produced directly as the primary output of the reactor's thermodynamic cycle, with electricity generated from part of the thermal energy.

Interest in nuclear-based district heating has increased in recent years, particularly in colder temperate climates with prolonged periods of heating requirements and regions dependent on fossil-based district heating, i.e. the Nordics and CEE[26]. Nuclear-based district heating has been pursued in Bulgaria, Czechia, Hungary and Romania (Ullmann et al., 2026). In existing district heating systems, substituting a fossil-fuel heat source with a nuclear heat source can be relatively straightforward, as the thermal distribution infrastructure is already in place. In some of these cases, nuclear reactors may compete favourably against heat pumps and electric-based heating (Sokka et al., 2024). In large municipalities, despite limitations related to the seasonality of heat demand, the required volumes might also allow economies of scale.

[26] Member States with significant district heating infrastructure (i.e. >10% share of total heat demand in the residential sector satisfied by district heating) include Austria, Bulgaria, Czechia, Denmark, Estonia, Finland, Germany, Hungary, Latvia, Lithuania, Poland, Romania, Slovakia, and Sweden (RAMBOLL, 2020).

LWRs provide an outlet water temperature of 120°C, which is sufficient to satisfy the thermal demands necessary for district heating (Leppanen et al., 2021)[27]. However, their economic viability depends on the proximity of the reactor to load centres, which should ideally be adjacent to, or at most, 5-15 km[28] for heat transmission to be economically feasible (in the form of water at low-grade temperature) (Kavvadias and Quoilin, 2018). This largely explains why nuclear district heating remains limited to a small number of cases in CEE, mainly in Czechia and Slovakia, where nuclear power plants are relatively closer to cities and district heating networks are historically well developed. In Finland's case, leveraging district heating from nuclear sources is feasible, as 45% of the national heat demand from buildings is provided through district heating networks (IEA, 2023). Other Member States lacking extensive infrastructure, for example, those in southern Europe, are unlikely to pursue a district heating pathway for nuclear applications – thus, not adopting a widespread form, but rather localised where demand exists, making it an application with a 'niche' prospect.

SMRs are currently being explored to expand these opportunities. More details can be found in section 5.3.

From a policy perspective, nuclear heat can qualify for district heating through technology-neutral efficiency criteria. Under the revised EED, the concept of efficient district heating and cooling (EDHC) foresees a combination of renewable energy, waste heat, and high-efficiency cogeneration in the system. Nuclear energy can enter the framework via high-efficiency cogeneration, contributing to EDHC compliance if the system meets overall efficiency thresholds of a combination of sources. However, eligibility depends on Member States' implementation.

The Energy Performance of Buildings Directive (EPBD) (EU) 2024/1275) complements this by driving demand-side decarbonisation of heat, requiring new buildings to move towards zero-emission standards by 2030 and progressively phasing out subsidies for fossil fuel-based heating systems. Being technology-neutral, it opens the case for nuclear-derived heat sources in district heating.

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[27] While some Gen II reactors are capable of providing heat for district heating applications, today, most of the reactors being used for district heating are Gen III.

[28] This is indicative but may vary on a case-specific basis. It has been suggested that heat transmission carries a heat content loss of 1% per km of pipeline. However, in a study, Fortum indicated economic viability in heat transmission for district heating from the Laviisa nuclear power plant to Helsinki, which is 80 km away (Kavvadias and Quoilin, 2018).

Industrial applications

Low-carbon industrial heat represents a potential market in the medium to longer term, but is currently a much less-developed application for nuclear energy. At present, LWRs provide only low-grade heat. Their heat use is therefore largely limited to industrial end-users who require low-temperature heat, including food and beverages, pulp and paper, plastics, or textiles, and certain chemical applications. While industrial low-grade heat (<100°C) is supplied across several Member States (e.g. Czechia and Slovakia) from nuclear sources, the extent of this remains limited. More energy-intensive industries typically require medium-to-high-grade heat (>100°C), which LWRs are therefore unsuitable to provide. Ongoing policy discussions explore pathways to decarbonise industrial heat, with a particular emphasis on its electrification.

Unlocking the full potential for industrial applications of nuclear-based heat is subject to the future outlet steam temperatures that can be achieved from reactors (Box 4). Further details on industrial uses of SMRs can be found in section 5.3.

As with district heating, industrial applications depend heavily on siting. Economic utilisation of nuclear heat requires reactors to be located close to demand centres. This is especially important for higher-temperature-grade applications, as heat transmission in the form of steam results in greater heat-content loss than water (Kavvadias and Quoilin, 2018).

Box 4. Higher temperature grade heat

High-temperature gas-cooled reactors (HTGRs) and molten salt reactors (MSRs) (Gen IV reactors) are still in maturing stages but stand to achieve high-grade temperatures, making it possible to decarbonise hard-to-abate industrial processes for which electrification is not an option. HTGRs in China have shown outlet temperatures of 750°C, while HTGRs developed in Europe by the Sustainable Nuclear Energy Technology Platform (SNETP) have shown outlet steam temperatures of 550°C. However, it is thought that European HTGRs could reach 750°C (NEA, 2022a; World Nuclear Association, 2024). MSR designs, which are still broadly at the experimental stage of technological development, are expected to achieve core outlet temperatures of 750°C (IAEA, 2023).

Achieving higher maturity levels for HTGRs would further expand the temperature range available for advanced hydrogen production cycles (Hercog et al., 2024). All HTGR concepts are, however, subject to the supply of high-assay low-enriched uranium

(HALEU) tri-structural isotropic (TRISO)[29] fuel, which is not widely available at present (NEA, 2022a). Very high temperature reactors could achieve temperatures of up to 950°C, further expanding their potential (NEA, 2022a; US Department of Energy, 2024a).

However, high-temperature electrolysis (HTE) and certain thermochemical cycles (e.g. copper-chlorine, operating at ~530°C) are already within the thermal reach of LMR designs, including sodium-cooled and lead-cooled fast reactor designs, currently under development (Abdulrahman et al., 2025; Singh et al., 2025). Unlike HTGRs, LMRs do not require HALEU-enriched TRISO fuel, as they can operate on mixed oxide (MOX) fuel derived from reprocessed spent fuel.

2.2.2. Hydrogen and e-fuels production

While next-generation Gen IV reactors are expected to achieve outlet temperatures suitable for a wider range of industrial processes, current nuclear-derived hydrogen offers an indirect decarbonisation pathway for hard-to-abate industrial sectors. In parallel, synthetic fuels (e-fuels) produced using nuclear electricity and low-carbon hydrogen can contribute to the decarbonisation of aviation and maritime shipping. System coupling may also contribute to system cost reductions (CIP et al., 2025; Gea-Bermúdez et al., 2021), as well as provide additional revenues for generation sources in the transforming electricity market.

More broadly, hydrogen and e-fuel production offer nuclear operators an additional route to monetise generation. As nuclear plants risk facing more frequent periods of reduced dispatch (section 3.2), diverting electricity towards hydrogen and e-fuel production may improve asset utilisation, support higher load factors for electrolysers, and create supplementary revenue streams. However, this can only be an additional, complementary revenue stream and is therefore unlikely to become a primary revenue source for nuclear power plants.

Hydrogen

Today, over 95% of the world's hydrogen production is fossil-fuel-based, primarily through the steam methane reforming process of natural gas. Electrolytic hydrogen represents <4% of the total hydrogen production worldwide (Behera et al., 2025).

[29] HALEU fuel is enriched between 5% and 20%, necessary for advanced nuclear reactor designs, such as HTGRs.

Nuclear-based hydrogen can be produced either by (i) directly coupling electrolysers to reactors (co-located in behind-the-meter configurations) or (ii) through electricity fed into the grid (front-of-the-meter configuration). While direct coupling is often regarded as the most cost- and resource-efficient, safety concerns have been raised about the integration of electrolysers at nuclear sites, given the high reactivity (thus flammability) of hydrogen[30] (Ireland et al., 2025).

Current LWRs allow for hydrogen production through *low-temperature electrolysis* (LTE), primarily making use of alkaline or proton exchange membrane (PEM) electrolysers[31]. This is possible as LTE does not require thermal input. Reactors can accommodate LTE with limited adjustments to existing operations to make nuclear power plants 'hydrogen-ready' by integrating electrolysers 'behind-the-meter'. LTE, however, offers relatively low conversion efficiencies (approximately 60-80%) compared to other pathways, thereby falling short in grasping full profit potentials (Busam et al., 2025).

High-temperature electrolysis (HTE), which produces hydrogen via a Solid Oxide Electrolyser Cell (SOEC), offers a potentially more efficient pathway, with efficiencies reaching 90% (IAEA, n.d.a), because of its improved thermal-to-hydrogen efficiency[32]. HTE is still in the early stages of development, but has the potential to unlock higher operating temperatures (i.e. 750-950°C) (Revankar, 2019). Although these are currently not achievable by current commercial reactors in the EU, HTE can sustain operating temperatures exothermically, with significantly lower temperature steam input (i.e. 150-200°C), making hydrogen production via nuclear-coupled HTE possible with existing reactors (Vostakola et al., 2023).

From an economic perspective, both renewable and nuclear hydrogen remain more expensive than conventional steam methane reforming processes. In Europe, the production costs, i.e. levelised cost of hydrogen (LCOH), of the latter stand at an average of 3.3 EUR/kgH_2, whereas direct production from renewable sources ranges between 4.3-10.5 EUR/kgH_2 (European Hydrogen Observatory, 2025), depending on the renewable source, location, and configuration (Alabbabi et al., 2024). Hydrogen production using grid-connected electricity from the power grid ranges from 4.1-16.1 EUR/kgH_2 (European Hydrogen Observatory, 2025).

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[30] The Bay Hydrogen Hub project at the Heysham 2 power station in Lancashire, UK actively demonstrates electrolyser co-location with a nuclear power plant, aiming to provide hydrogen for the cement and asphalt industries.

[31] Alkaline electrolysers are the most widely adopted type. These use a liquid alkaline solution, typically potassium hydroxide, to carry out electrolysis. Alkaline electrolysers are currently the most mature and cost-effective electrolyser technology.

[32] Compared with LTE, HTE has a lower electrical energy requirement (35%) and a higher chemical reaction rate, making it a more appealing option for future large-scale hydrogen production (IAEA, n.d.a.; IAEA, 2024a).

For nuclear-based hydrogen, LTE coupled to existing GW-scale reactors can allow for costs estimated between 5.7-7.7 EUR/kgH_2, depending on the capacity of the nuclear plant. This can potentially be lowered in the future to 3.3 EUR/kgH_2, considering the adoption of an HTE+HTGR configuration[33] (Alabbabi et al., 2024), reaching cost parity with the conventional steam methane reforming. HTGRs, however, are not commercially available in the EU, making it a longer-term prospect.

One of nuclear energy's principal advantages for hydrogen production is its high capacity factor. Electrolysers are capital-intensive assets whose unit costs of hydrogen production decrease significantly as utilisation rates increase. Comparing these with the average EU capacity factors of onshore wind (24%) and solar PV (11%) (Juge et al., 2026), higher utilisation rates enable greater nuclear-based hydrogen output per unit of electrolyser capacity, therefore lowering the amortised cost per kilogram of hydrogen. The NEA (2022b) estimates that amortised LTO reactors could reach production costs of <2 EUR/kgH_2 by 2035. Nevertheless, the future competitiveness of nuclear-based hydrogen will ultimately depend on broader hydrogen market development, infrastructure deployment, and the relative cost evolution of competing renewable and low-carbon production pathways, including the HTGR+HTE pathway, often cited as the most promising production method.

Despite earlier optimism, both low-carbon and renewable hydrogen currently face significant headwinds in Europe. Hydrogen demand remains weaker than expected, reflected in a limited number of offtake agreements, while deployment of hydrogen infrastructure continues to lag behind policy ambition. These developments raise important questions about whether the EU can deliver on its hydrogen ambitions, and ultimately, about the role that nuclear power will be able to play in that trajectory.

While nuclear-based hydrogen has been recognised as low-carbon hydrogen, its regulatory treatment is yet to be fully addressed. First, although its exclusion from RFNBO status under RED III reflects its non-renewable nature, this means that nuclear-produced hydrogen cannot contribute towards the legally binding RFNBO targets for industry and transport. As a result, it has more limited access to demand-side incentives, weakening its business case compared with renewable hydrogen pathways. Second, in its recent Accelerate EU communication, the Commission acknowledged the slower-than-expected ramp-up of the hydrogen market and announced work on a methodology to define criteria for recognising low-carbon electricity from nuclear power plants. Greater

[33] This pathway is considered more economical because of the higher thermal output of reactors, avoiding thermal-to-electric conversion.

regulatory clarity regarding the role of nuclear-derived hydrogen would reduce investment uncertainty and strengthen its long-term deployment prospects.

E-fuels

Low-carbon (or carbon-neutral) e-fuels are synthetic fuels produced by combining carbon captured from various sources[34] with hydrogen generated through electrolysis. This process yields hydrocarbons that can serve as lower-carbon alternatives to conventional fossil fuels[35] in applications where electrification is neither technically nor economically feasible, among others, for industrial applications and the aviation and maritime transport sectors (Dell'Aversano et al., 2024).

While EU e-fuel production policies have long earmarked renewable electricity as the main input, nuclear-based production may offer a promising alternative, again because of its reliable and continuous supply of low-carbon electricity. This would require co-location and integration of e-fuel production facilities along with nuclear reactors, enabling behind-the-meter[36] electricity to run electrolysers and DAC systems (Delgado et al., 2023).

Current assessments suggest that e-fuels produced from newbuild nuclear remain more expensive than those of solar PV and onshore wind, while production using retrofitted LTOs may be more competitive (Rasamary, 2025). Given that hydrogen production remains the dominant cost component of e-fuels, improvements in hydrogen production costs and advancing technological maturity are essential prerequisites for wider commercial deployment of e-fuel synthesis.

2.2.3 Desalination

Desalination is an energy-intensive process that produces potable water from seawater or brackish water. Depending on the technology employed, desalination requires electricity, low-grade heat, or both. The most widely used method is reverse osmosis (RO), a membrane filtration process powered exclusively by electricity to drive pumps. Other methods, such as the multiple-effect distillation (MED) and multi-stage flash (MSF), require low-grade heat (below 100°C) to drive evaporation and condensation. These systems are currently less prevalent than electrically driven RO plants.

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[34] Direct Air Capture (DAC) systems are often quoted as the preferred option for CCS coupled to nuclear reactors. DAC, however, remains at low technology-readiness levels (TRL) (4-6) (Dell'Aversano et al., 2024).

[35] Produced hydrocarbons are diverse, e.g. synthetic e-gasoline, e-diesel, or e-kerosene through processes including Fischer-Tropsch synthesis or e-methanol to gasoline conversion (Rasamary, 2025).

[36] The use of behind-the-meter electricity avoids grid charges and taxes, lowering the final cost of production.

Globally, most desalination facilities are powered by fossil fuels. Although vRES can technically supply the required energy, their intermittency combined with insufficient BESS capacity limits their ability to, at present, meet the continuous loads needed by desalination plants (El-Emam et al., 2022). Co-located nuclear power and desalination plants can continuously co-generate electricity and water, either through electrical, thermal or hybrid coupling, depending on the plant's inputs. WCRs are capable of meeting both the electrical and thermal requirements.

While nuclear desalination is technically and economically competitive, the extent to which it can be adopted in Europe remains geographically limited. No nuclear reactors in the EU currently provide desalination services, and globally, only a few units in China, India, Japan, and Pakistan are coupled with desalination facilities (Khan and Ofri, 2021). Interest is growing in water-stressed regions, particularly in the Middle East, where nuclear-powered desalination is increasingly being considered (Zubair and Sajna, 2026). In Europe, desalination capacity is concentrated in southern Member States, primarily in Spain, Italy, Malta, Greece, and Cyprus (EU Blue Economy Observatory, n.d.), but none are currently pursuing new nuclear build projects.

3. Economics of nuclear in a decarbonising energy system

This section analyses the changing economics of nuclear energy in an evolving electricity system. Section 3.1 examines the plant-based costs of nuclear, compares them with other generation technologies and discusses alternative metrics, and section 3.2 analyses nuclear economics within the current EMD, analysing the (potential) evolution of revenue streams.

3.1. Levelised cost of electricity and beyond

This section focuses on LCOE as a plant-level cost assessment. First, it outlines the composition of nuclear LCOE for newbuild and LTO (section 3.1.1); second, it compares nuclear LCOE with other generation technologies (section 3.1.2); and finally, it discusses alternative metrics that capture costs beyond conventional LCOE (section 3.1.3).

3.1.1. LCOE for newbuild and long-term operation reactors

When evaluating the cost competitiveness of electricity-generation technologies, a ‘lifetime’ approach is typically used as the standard, with the LCOE being the most commonly used metric. LCOE measures the expected discounted lifetime costs of building and operating a power plant relative to its expected power output. It comprises both the project’s capital expenditure (CAPEX) and operational expenditure (OPEX), discounted over the project’s lifetime using the weighted average cost of capital (WACC) as the discount rate. LCOE enables comparison of energy generation technologies on a consistent basis, despite differences in costs, returns, or lifespans.

For nuclear energy, CAPEX typically accounts for over 60% of total LCOE (World Nuclear Association, 2026), making it the dominant cost component. CAPEX account for the full costs encountered prior to the nuclear power plant entering operation, including the overnight cost, construction and investment costs, financing costs, and may include costs prior to the start of construction, for example, permitting and licensing costs.

OPEX comprises all fixed and variable costs incurred during plant operation, including operation and maintenance (O&M), fuel and waste management, and decommissioning costs. Nuclear LCOE calculations often fully internalise decommissioning expenditure (DECEX) and total fuel costs. DECEX is incurred after plant closure and may extend from 20 to over 100 years, depending on the reactor type, although it does not usually constitute a significant part of OPEX (NEA, 2003). The total fuel costs represent around 17% of total power generation costs (NEI, 2025) and comprise the front and back end of the fuel cycle, including fuel processing, management and disposal stages. Compared with other fuel-dependent technologies that are more exposed to fuel costs[37], nuclear is relatively insulated from short-term fuel price spikes because uranium is typically procured and stockpiled years in advance of refuelling stages and remains in reactors for 4-6 years. Spikes in uranium prices, for example, the 2007-2008 peak of >130 USD/lb (EUR >250/kg), do not tend to affect fuel costs until several years later (NEI, 2025).

Newbuilds

The construction of nuclear newbuilds is characterised by high upfront CAPEX investments, which are gradually offset by relatively low, predictable variable generation costs during operation, high capacity factors and long asset lifetime. LCOE estimates for newbuilds typically assume capacity factors of 85-90% over a 60-year operating lifetime.

Financing costs are the single most important driver of LCOE variations for CAPEX-intensive technologies and are especially crucial for new nuclear, given its long construction periods and high overnight costs. Delays during construction can therefore significantly increase project costs (section 4.1). As most economic returns only originate from long-lived future cash flows, often decades away from initial investment phases, newbuilds are particularly sensitive to the risk-adjusted discount rates used in LCOE calculations. Discount rates reflect the time value of money, the cost of capital, and project risk – with lower-risk technologies often assessed at 3-5%, for example, solar PV, and higher-risk projects, including newbuilds, at 7-10%. Cross-technology LCOE evaluations typically use a 7% discount rate.

LCOE estimates for new nuclear vary widely across sources, reflecting high sensitivity to the assumptions made in the calculations and the variety in regional resource conditions. Estimates range from an optimistic 49 EUR/MWh (DNV, 2025) to an elevated 370 EUR/MWh (BNEF, 2026a), although most values typically fall between 100 and 200 EUR/MWh. According to the IEA and NEA (2020), nuclear generation costs are comparatively low in Russia, South Korea, China and India, ranging from 45 to 72 EUR/MWh, while estimates from the US, Japan and the EU show higher values of between 77 and 112 EUR/MWh. However, these values should be interpreted as indicative averages only, as project-specific conditions substantially affect assessments, highlighting their substantial variability.

Long-term operation

The LTO of nuclear power plants refers to the continued operation of reactors beyond their original licensed lifetime, which is typically set at 60 years (US Department of Energy,

[37] E.g. in CCGT plants, gas prices could reach up to 90% of marginal costs under high market price scenarios (World Nuclear Association, 2026).

2020). If an LTO licence is granted, it can remain operational for a further 10-20 years before retirement, reaching total operational lifetimes of around 80 years. LTO requires targeted investment in modifications to plants' operations and to the reactor itself. These include material technology issues related to neutron irradiation, degradation of cables and piping, upgrading of instrumentation and control systems, and human resources related to reactor operation (Aszódi et al., 2023).

The cost structure of LTO differs considerably from that of newbuilds. As the original CAPEX has largely been recovered, the main cost drivers during LTO become OPEX and life-extension CAPEX associated with safety upgrades and potential component replacements (e.g. steam generators and turbines). Consequently, LTOs rank among the most cost-efficient generation sources.

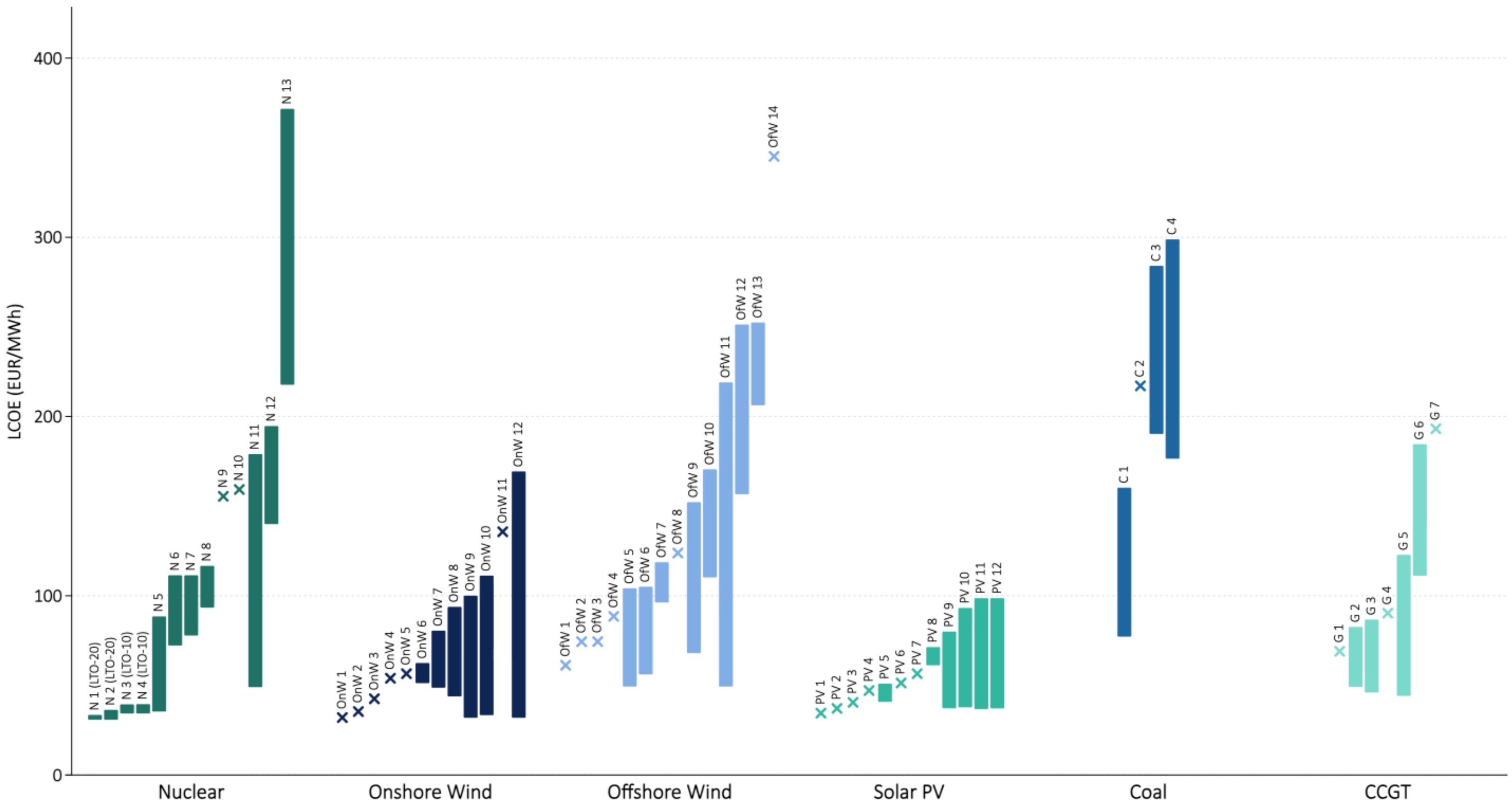
The IEA and NEA (2020) quantify the LCOE for LTO at 34-39 EUR/MWh for 10-year extensions and 31-36 EUR/MWh for 20-year extensions. LTO is therefore one of the most cost-efficient ways of 'adding capacity' to the grid. While LTO does not create new capacity as such, it preserves existing generation capacity that would otherwise have been retired, hence providing capacity availability that may not have been previously considered. LTO also retains all other benefits associated with nuclear, for example, low-carbon generation and asset-level grid stability provisions (section 2.1).

3.1.2. LCOE comparison with other technologies

LCOE is best suited for comparing technologies with similar characteristics, that is, either within the same technology group or those with similar generation profiles. Its comparison effectiveness decreases when conducting cross-technology economic comparisons. Nevertheless, plant-level cost comparisons remain widely used and provide a useful starting point for assessing the cost competitiveness of nuclear power.

LTOs remain highly competitive against all generation technologies, with LCOEs of 34-39 EUR/MWh for 10-year LTO and 30-36 EUR/MWh for 20-year LTO. Nuclear newbuilds (72-111 EUR/MWh), when compared with other dispatchable technologies, are generally more competitive than coal-fired (282 EUR/MWh) and CCGT (200 EUR/MWh) power plants (IEA and NEA, 2020). Hydropower (48 EUR/MWh) showcases lower LCOE values, although its deployment and economics are highly geographically dependent. Compared with vRES, nuclear newbuilds appear less competitive under an LCOE-only approach. Solar PV stands at 49 EUR/MWh, whereas offshore and onshore wind are at 68 and 59 EUR/MWh, respectively (IRENA, 2025). Figure 9 provides a broader comparison of LCOE estimates of selected technologies, with detailed estimates presented in the Supplementary Information.

Figure 9. Compilation of LCOE estimates for different technologies, including ranges and individual values



Source: authors' composition. Sources available in the Supplementary Information.

Note: nuclear LCOE encompasses values representative of newbuild, as well as LTO – represented as LTO-10 and LTO-20 for 10- and 20-year lifetime extensions, respectively.

3.1.3. Beyond LCOE: Wider system costs

LCOE is most useful for comparing similar power generation technologies on a consistent per-plant basis, but it does not capture the full economic implications of different technologies for the electricity system. As discussed in section 2.1.5, technologies differ in their contributions to adequacy, flexibility, grid stability, and balancing, which in turn affect total system costs. Consequently, LCOE does not fully reflect either the value that a technology provides to the system or the costs associated with integrating it.

To address these limitations, alternative metrics have been developed. Table 3 compares LCOE estimates with selected alternative metrics across generation technologies, illustrating how assessments of technology's cost competitiveness change when broader system considerations are incorporated. In general, these metrics tend to improve the relative position of nuclear in terms of economics compared with asset-only LCOE assessments.

Table 3. Cross-technology comparison of electricity generation costs as calculated by different metrics: LCOE and alternatives

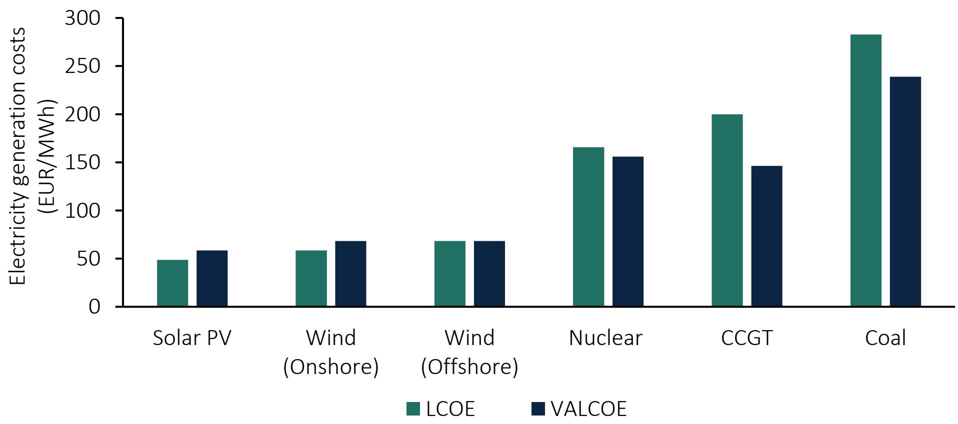
	Generation costs (EUR/MWh)			
Metric	Nuclear	Solar PV	Wind	Reference
LCOE	77 71-160 126-196	34 42-52 24-64	38 38-57 26-81	(Idel, 2022) (IEA, 2024) (Lazard, 2025)
VALCOE	66-142	44-62	40-62	(IEA, 2024)
LCOE including firming	n/a	159-135 29-52 115	43-62 40-65	(Lazard, 2025) (IRENA, 2026) (Ember, 2025)
LFSCOE-95	85-90	166-706	123-229	(Idel, 2022) (B of A Securities, 2023)
LFSCOE-100	99-115	390-1 300	274-454	(Idel, 2022) (B of A Securities, 2023)

Source: adapted from Samark-Roth et al. (2025).

One such metric is the *value-adjusted levelised cost of electricity (VALCOE),* developed by the International Energy Agency (IEA). In addition to standard LCOE calculations, VALCOE incorporates technological contributions to flexibility provision and capacity in the wider electricity system (Kabeyi and Olanrewaju, 2023; IEA, 2024). Figure 10 compares LCOE and VALCOE values across generation technologies. Where LCOE exceeds VALCOE, the technology's economic competitiveness is improved when the broader services it provides to the electricity system are accounted for. Conversely, a higher VALCOE indicates a loss in the technology's competitiveness. Accordingly, nuclear power plants generally benefit from the broader services they provide to the energy system. Nevertheless, VALCOE still does not account for all system-specific costs. Expenses related to grid integration and system-specific considerations are excluded, as these can only be accurately assessed through in-depth system-specific assessments (IEA, 2025a). Figure *10*, therefore, presents only a partial view of reality.

Another approach, *'LCOE (including firming)'*, incorporates the costs of providing firm electricity supply. For instance, if solar PV is to provide firm capacity, the storage component (BESS) shall also be accounted for to enable round-the-clock electricity provision by this hybrid PV-BESS. These costs are not captured in conventional LCOE (or VALCOE) calculations (Figure 10). Ember (2025) quantifies these costs at 115 EUR/MWh. An increase from the average standalone PV LCOE of 41 EUR/MWh (IRENA, 2025), this would make solar PV's LCOE more comparable to that of nuclear newbuild, although it would remain at a margin below new nuclear. It is important to note that the costs of PV-BESS systems are declining at high rates as a result of reductions experienced in both PV and BESS units.

Figure 10. Electricity generation costs by technology in the EU



Source: authors' composition. Data from IEA (2024).

Other metrics seek to quantify the full costs of reliable electricity supply by technology. One example is the *levelised full system cost of electricity (LFSCOE)*, developed by Idel (2022). It quantifies the costs of full electricity provision by a specific technology meeting all balancing and supply obligations to the entire market at 95% (LFSCOE-95) or 100% reliability (LFSCOE-100). Under this framework, LFSCOE values for Germany were estimated at 102 EUR/MWh for nuclear power, offshore wind at 470 EUR/MWh, and solar PV at 1 343 EUR/MWh.

3.2. Economics of nuclear under the Electricity Market Design

This section examines how evolving electricity market dynamics affect nuclear economics: section 3.2.1 analyses the consequences for nuclear revenues, and consequent increasing importance of long-term contractual arrangements, including government-backed price stabilisation mechanisms; and section 3.2.2 considers additional revenue sources, which are, however, expected to remain limited compared with revenues from electricity sales.

3.2.1. Revenues from electricity sales

This section examines how the EMD (Box 5) translates into revenues for nuclear power plants, focusing on dispatch dynamics, wholesale price trends, and the role of long-term contracts.

Increasing displacement in dispatching

Nuclear power plants have short-term marginal costs that are lower than those of all other thermal and hydropower plants, but above the near-zero marginal costs of vRES. As a result, nuclear generation is dispatched after vRES. Nuclear power plants have historically played the role of baseload generators, which is best adapted to their operational and economic profiles (section 2.1). Alongside the rising shares of vRES, nuclear units are, however, increasingly pushed towards a more flexible, residual load-following asset, facing fewer operating hours as renewables penetration increases (Next Kraftwerke, 2022).

Consequently, nuclear generation is at risk of being increasingly displaced from dispatch – unless electricity demand rises substantially. As of 2022, gas peaking generation set prices around 55% of the time in the EU, followed by coal, lignite, and nuclear generators. The JRC (2023) projects that until 2030, gas will remain the dominant price-setting technology (86% of the time), while coal and lignite power plants are progressively displaced. By then, nuclear is expected to set prices more frequently, especially in France, Finland and Sweden, which will most likely experience the initial impacts of nuclear plant displacement out of the merit-order system.

Decreasing dispatch creates a risk that newbuild projects may become unable to efficiently recover their fixed costs on the wholesale market. Studies suggest that even with flexible operation, nuclear plants must ideally operate at load factors close to 90% to effectively recover their investment costs. These developments can be particularly detrimental for nuclear newbuild business cases with their disproportionately high fixed-to-variable cost ratios (section 3.1).

Box 5. Evolution of the Electricity Market Design

At the core of the EMD lies the day-ahead market, based on merit-order dispatch and marginal pricing, complemented by intraday, balancing and ancillary services, and forward markets. Over time, additional instruments have been layered onto this framework, including long-term price stabilisation mechanisms, such as CfDs and PPAs, capacity remuneration mechanisms (CRMs), and emerging flexibility markets. This architecture has gradually evolved through successive liberalisation packages (1996, 2003, 2009), the Clean Energy Package (2018), and the 2023-2024 market reform.

Wholesale electricity prices are primarily formed in the day-ahead market under merit-order dispatch, where generation is ranked by ascending marginal cost. Near-zero marginal cost renewables are dispatched first, followed by progressively higher marginal cost technologies. The marginal unit sets the clearing price, which is paid uniformly to all generators. Historically, this 'energy-only' design assumed that higher prices during scarcity periods would enable inframarginal generators to recover fixed costs from electricity sales.

However, alongside increasing shares of vRES, increasing hours of low-marginal generation meeting demand suppresses average wholesale prices, raising concerns over investment incentives for both inframarginal and marginal technologies. In the late 2010s, this earlier trend was reinforced by relatively low gas prices, contributing to structurally depressed wholesale electricity prices. The 2022-2023 energy crisis temporarily reversed this trend through exceptionally high gas-driven electricity prices. The 2023-2024 electricity market reform, therefore, strengthened the role of long-term contracts in supporting investment certainty, though without resolving longer-term structural concerns.

At the same time, assets needed for system adequacy but operating less frequently (e.g. during low renewable generation stress periods) face the 'missing money' problem. In response, CRMs have become more structural elements of the EMD, aimed at ensuring capacity adequacy and incentivising availability. In parallel, flexibility markets are being developed to better value services such as demand response and storage, reflecting the evolving needs of a decarbonised electricity system.

These developments have intensified debates on the future design of the EMD, particularly regarding price formation and investment incentives. While alternative models have been proposed, the prevailing EU trajectory suggests continuity in the core architecture – especially marginal pricing – with reforms focusing on layering additional mechanisms rather than resulting in an overhaul of the system. This has far-reaching effects for nuclear generation.

Increasing wholesale electricity price volatility

Increasing shares of vRES, combined with insufficient system flexibility, can amplify wholesale price volatility, increase hours of negative prices and exert downward pressure on average prices. These effects are particularly pronounced in systems with grid congestion and a lack of demand-side flexibility, storage capacity, and cross-border interconnectors, especially during hours of vRES surplus and/or low demand (Wang et al., 2024; Pavlik et al., 2025; Antweiler and Muesgens, 2025). During the first half of 2025, negative price hours accounted for up to 9% in some EU markets, with the Netherlands (9.2%), Spain (9.0%), Germany (8.1%) and Sweden (7.9%) among the most affected – correlating with high shares of vRES (IEA, 2025b).

For nuclear, price volatility significantly affects both newbuild investment and operations. During negative price periods, plants may continue running, also at reduced loads, or directly face shutdown to avoid excessive economic loss, in case such periods are long. However, curtailing power generation from nuclear is not cost-effective either, as this process may impact equipment negatively and may require additional safety checks (section 2.1.2). As a result, nuclear units often continue to be online even when wholesale electricity prices fall below their costs (e.g. in zero- and negative-price hours), incurring additional economic losses. This makes nuclear units even less financially viable in markets with frequent periods of low prices driven by high renewable output. In principle, these impacts can be partially mitigated through operational optimisation (e.g. refuelling or maintenance during high vRES periods), long-term or forward contracting, and flexible dispatch, both during price peaks and periods of low/negative pricing.

However, the key uncertainty remains the evolution of average wholesale electricity prices and price spreads, raising questions about investment incentives for all generation technologies in a context of structurally declining wholesale prices. As inframarginal technologies are expected to increasingly set price levels in periods of high vRES output, average revenues may come under sustained downward pressure, especially after 2030. This is particularly relevant in regions such as the Nordics, where high renewable penetration already contributes to structurally low price levels.

A more granular reflection of cross-zonal constraints as a result of the Grids Package could also lead to more frequent price divergence between bidding zones and, therefore, greater revenue uncertainty for generators exposed to wholesale markets. For nuclear power, these dynamics may become particularly consequential. Nuclear power plants are generally designed for high capacity factor operation and may therefore be structurally more exposed to periods of low or negative prices, unless operated in a more flexible, price-responsive mode.

Price stabilisation mechanisms: CfDs and PPAs

Although factors such as permits, environmental impact assessments or grid connections can severely impede low-carbon project advancement, the ultimate ratio for inflows of private investment is the profitability and bankability of these projects – a conundrum faced by many CAPEX-heavy, low-carbon and renewable projects under the EMD (Kustova et al., 2024). Investment in CAPEX-heavy generation requires predictable revenue streams from electricity sales (and potentially other thermal vectors) to cover debt payments and current costs. Revenue uncertainty can lead to higher risk premiums, making projects less attractive to investors. Therefore, price stabilisation has become a crucial aspect of investment decisions.

The 2022-2024 electricity market reform addressed this chronic difficulty of stimulating long-term low-carbon investment in generation by strengthening long-term price stabilisation mechanisms, that is, CfDs and PPAs. Under Article 19(d) of the revised Electricity Regulation, Member States are encouraged to deploy such mechanisms, including CfDs or equivalents, on a technology-neutral basis for low-carbon generation technologies.

Contracts for Difference

CfDs are long-term agreements between plant operators and a public counterparty, typically awarded via competitive auctions. Developers bid a strike price; the lowest bids are selected. Once operational, the operator receives top-up payments when wholesale prices fall below the strike price and repays excess revenues when prices exceed it. This reduces the long-term impact of price volatility, stabilising revenues and lowering financing costs, while maintaining exposure to operational performance.

CfDs reduce certain revenue volatility and financing costs, but do not eliminate volume risk, as revenues remain dependent on the actual power generation[38], and preserve risks linked to reduced dispatch or operational constraints. However, lower expected revenues from the electricity market – resulting from reduced power outputs due to load-following operation – would ultimately translate into a higher CfD strike price. These losses could be compensated through appropriately designed and calibrated support schemes,

[38] Conventional CfDs are production-based, meaning that payments are linked to a plant's actual electricity generation. However, the Commission's guidance also allows for production-independent CfDs. Under this approach, payments are linked either to the plant's available capacity at a given time or to the output of a virtual (reference) power plant, rather than actual generation. Production-independent CfDs provide incentives for plant operators to adjust generation and market participation in response to market conditions, thereby helping to reduce volume risk. Hybrid (or 'fusion') CfD designs – also allowed by the Commission's guidance – combine elements of both approaches. In these arrangements, payments are generally linked to actual generation but become decoupled during periods when: (i) generation is curtailed at the request of DSOs/TSOs, (ii) day-ahead market prices are negative, or (iii) intra-day market prices are negative.

subject to discussion between developers, operators and relevant Member State governments.

CfDs seem to serve LTOs well, as existing nuclear power plants are characterised by sunk costs and therefore do not require additional de-risking mechanisms. Shorter contracts of 10- to 15-year duration align better with CfD designs and can provide certainty to investors. For example, the Doel 4 and Tihange 3 reactors in Belgium were granted State aid to operate under CfD schemes for their 10-year lifetime extensions (European Commission, 2025d). However, while extending CfDs to existing nuclear assets supports continued operation, it may risk overcompensation and could distort investment signals for new capacity, requiring a careful State aid assessment (section 4).

For nuclear newbuilds, CfDs are likely to become a default option, already being applied in a number of newbuilds (section 4). However, while CfDs can stabilise market revenues to a certain extent during operation, they do not address construction risks. As a result, CfDs alone may be insufficient to ensure bankability without complementary instruments.

Power Purchase Agreements

PPAs are long-term bilateral contracts between generators and offtakers, in which an offtaker commits to purchasing electricity from a plant operator at a fixed price, typically before the power plant is constructed. Increasingly used in renewable projects, PPAs offer standalone payments that complement those from electricity volumes sold directly in the wholesale market. In Europe, PPAs typically last 10-20 years, with 11 years being the most common contract length. While this timeframe often aligns with that of many renewable energy assets, it falls far short of the operational lifetime of a nuclear reactor (up to 60 years)[39] (Nucleareurope, 2023; Krivanek, 2020). Plant operators and offtakers are, however, allowed to determine the agreement's duration. But it is evident that a single PPA agreement would only cover a limited portion of the nuclear power plant's power production period.

In practice, pure merchant PPAs for nuclear newbuilds remain rare in Europe. Some limited PPA-like arrangements exist for existing nuclear power plants or for corporate sourcing of nuclear electricity (e.g. in Finland or Sweden), but these do not represent a widespread financing model for new nuclear deployment yet.

[39] Refers to operational period excluding LTOs.

3.2.2. Additional revenue streams

This section examines whether nuclear power plants can meaningfully rely on additional revenue streams beyond wholesale electricity sales. It focuses on balancing and ancillary services as well as CRMs.

Revenues from balancing and ancillary markets

Nuclear revenues are primarily derived from electricity sales under high capacity factor operation, and income from balancing and ancillary service markets represents only a marginal share of total revenues, the case being true for all power generation assets. This is unlikely to change substantially in the future.

Balancing markets ensure real-time equilibrium between supply and demand, managing frequency deviations, which arise when actual generation and demand diverge from scheduled positions. Such imbalances result from forecast errors, vRES viability, unplanned outages or demand spikes. TSOs activate balancing energy (i.e. real-time mismatch energy in MWh) and capacity (reserved availability ahead of time) bids submitted by balancing market participants, that is, generators, storage operators, and demand response providers. While conventional generators have historically dominated these markets, BESS and demand-side resources are playing an increasingly important role, although the pace of their integration varies across Member States.

For nuclear plants, participation in balancing markets is technically possible but limited. More broadly, balancing markets rewards flexibility, fast response, and short-term operational agility. By contrast, nuclear plants are optimised for continuous, stable output, and while load-following is technically feasible, adjustments are generally slower and often not economical. Their role is more passive and generally centred on downward modulation first (i.e. reducing output in situations of excess generation) and similar upward modulation subsequently, depending on technical constraints and operating regimes.

Ancillary services ensure system reliability and stability functions, that is, frequency stability, voltage control, inertia, and black start capability. Products vary in terms of response time and duration of reaction: frequency containment reserve (FCR), which operates within seconds; automatic frequency restoration reserve (aFRR), which responds within minutes; and manual frequency restoration reserve (mFRR), which is typically activated within 15-60 minutes.

These services are procured by TSOs, primarily at the national or regional level, although there is increasing cross-border coordination (e.g. through platforms such as PICASSO for aFRR and MARI for mFRR). Remuneration structures vary across Member States and products, combining capacity payments (i.e. EUR/MW for availability) and activation payments (i.e. EUR/MWh for delivered energy). However, overall market size remains essentially limited compared with wholesale electricity markets, making ancillary services only a supplementary revenue source.

Nuclear plants provide several ancillary services, including FCR (subject to national rules), aFRR (notably in more flexible fleets such as in France), mFRR, and voltage control, which is commonly provided as part of standard operation. However, participation depends on technical characteristics such as technical ramp limits and regulatory frameworks.

Although in certain Member States the FCR service is procured through the markets, sometimes even at a regional level (see the FCR Cooperation, whose participants are countries of the CORE Region), in many countries it remains a mandatory requirement for large dispatchable power plants, which must provide it free of charge. In Italy, there is a gradual shift towards a system where FCR service procurement follows market-based principles. France represents one of the most advanced cases of nuclear participation in system services, while involvement remains more limited in Belgium, Finland, Sweden, and Romania, reflecting fleet characteristics, regulatory choices, and the availability of alternative flexibility sources (e.g. hydropower in the Nordics and Romania).

Overall, ancillary services in Europe are evolving gradually from regulated or bilateral arrangements towards more market-based procurement, driven by the increasing need to integrate vRES, as well as the growing role of battery storage and demand-side response (Rancilio et al. 2022). Despite these differences, ancillary service revenues remain small for nuclear, typically around 1-5% of total revenue (IEA, 2019). More structurally, ancillary service markets tend to reward fast response and operational flexibility, which places inherently less flexible technologies, such as nuclear, at a relative disadvantage. At the same time, nuclear power plants provide significant system inertia through large rotating masses, an increasingly valuable attribute as synchronous generation declines, as discussed in section 2.1. This raises broader questions about whether mechanisms for such remuneration should be explored.

System adequacy remuneration (CRMs)

System adequacy in the EU is increasingly supported through CRMs, which become a more structural component on top of the energy-only market. Unlike energy markets, CRMs remunerate available capacity rather than actual generation, paying for the ability to dispatch when electricity is needed. These payments are typically open to power generators, storage operators, and demand-side response providers (Holmberg et al., 2025). Historically, thermal power plants have been the main beneficiaries of CRMs because of their dispatchability and their ability to adjust power output relatively fast.

The need for such mechanisms has grown due to the (i) greater shares of vRES generation, (ii) limited flexibility and storage capacities, and (iii) constrained interconnections. These raise concerns about resource adequacy during rare but critical stress hours. CRMs, therefore, emerged as a key policy tool to incentivise capacity availability where energy-only markets may under-provide investment signals. The Clean Energy Package (2019) established this framework, and the 2022-2024 electricity market reform reinforced it.

At the EU level, CRMs are permitted under strict conditions: they must be justified by adequacy concerns, remain proportionate, and minimise distortions. By 2025, eight Member States had implemented CRMs, with payments exceeding EUR 6 billion, concentrated in France, Italy, and Poland (ACER, 2024; Eurelectric, 2025). As the importance of maintaining system adequacy gains increasing recognition, capacity payments are likely to become more significant.

In principle, nuclear is eligible under the technology-neutral framework laid out in the Electricity Regulation 2019/943. Nuclear plants' high availability and dispatchability can add value, also providing an opportunity to access further revenue streams[40]. However, in practice, participation varies significantly. France includes nuclear in its capacity obligation scheme; in contrast, Belgium introduced CRMs partly because of the former decision to nuclear phase-out, while the UK excludes nuclear from its capacity market. In some cases, participation in CRMs may limit eligibility for other support schemes (Elia Group, 2025).

Importantly, CRM design tends to favour flexible and peaking resources, such as gas-fired plants, storage, and demand response, which are better suited to addressing short-term stress events. Nuclear, typically operating as baseload generation, is therefore less likely to be the marginal provider in such mechanisms[41]. More fundamentally, wherever nuclear is eligible, CRMs do not address the core challenge for nuclear: recovery of high upfront capital costs over long investment horizons. Instead, they partially mitigate revenue adequacy concerns by providing additional revenues.

[40] Although nuclear power stations could serve as strategic reserve receiving capacity payments, it may also be the case that other types of power plants may serve as strategic reserve in the event of nuclear plant unavailability, as experienced in France in 2023 (Holmberg et al., 2025).

[41] The suitability of CRMs for nuclear depends on the design of the CRM itself. For instance, the CRM design in Italy requires year-round availability. Such a framework would make CRMs for baseload technologies viable.

4. Building new nuclear in Europe

This section examines the key enabling conditions for new nuclear deployment in Europe. It first analyses construction-related aspects (section 4.1) and then assesses financing conditions and support mechanisms for newbuilds (section 4.2).

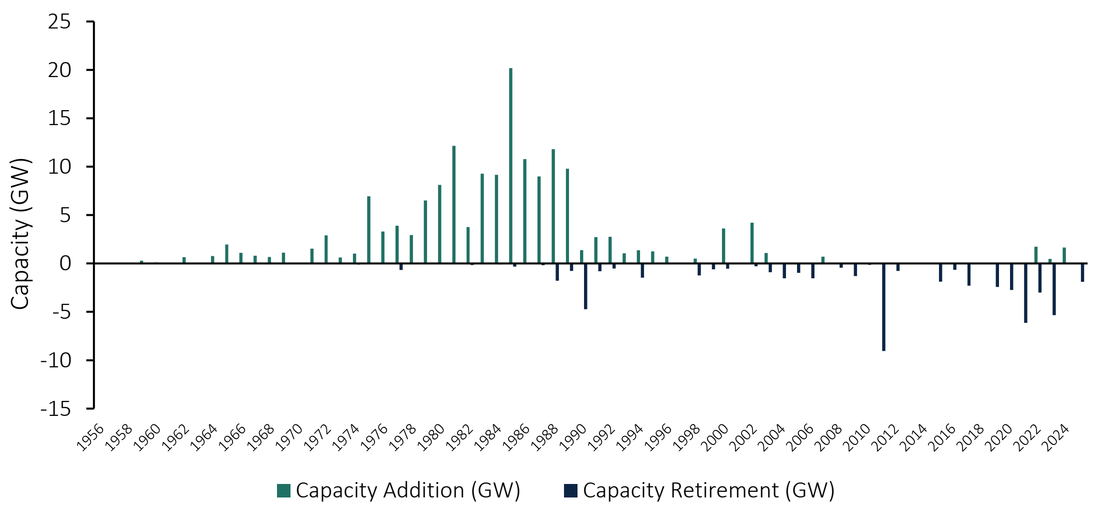
4.1. Newbuild delivery: construction, supply chains and skills

This section discusses the challenges and conditions of deploying new nuclear in the EU. Rebuilding the EU's industrial capacity remains a central challenge. While non-EU vendors may help address some deployment needs, a robust domestic industrial ecosystem and skilled workforce remain essential for project delivery and for maximising the economic value added of nuclear within Europe. Without addressing project delivery challenges, cost and schedule overruns (section 4.1.1), supply-chain constraints (section 4.1.2), and workforce shortages (section 4.1.3), reducing construction costs and delivery times for future projects will remain difficult.

4.1.1. Construction track record and delivery challenges

Most of Europe's nuclear power capacity was built during the 1970s and 1980s, with a prolonged period of stagnation following, with only minor additions to the fleet (Figure 11). Combined with an ageing fleet approaching, or already undergoing, decommissioning, national phase-out policies, and the uptake of other low-carbon generation sources, this has contributed to a decline in nuclear energy's share in EU electricity generation to around 23%, down from 34% in 1997 (Eurostat, 2025; IEA, 2025c).

Figure 11. Annual capacity additions and retirements in the EU from 1956 to 2025



Source: authors' composition. Data from Global Energy Monitor (2025a) and WNISR (2026a).

Over the past two decades, only four new nuclear reactors entered commercial operation in the EU: Cernavodă-2 (Romania, 2007), Olkiluoto-3 (Finland, 2022), Mochovce-3 (Slovakia, 2024) and Flamanville-3 (France, 2024). A few reactors are currently under construction, planning, or proposal stages across Member States (Table 4). This contrasts sharply with some non-OECD countries, and in particular China, which dominates recent global capacity additions and is expected to overtake the EU and the US in installed nuclear power capacity by 2030 (IEA, 2025c).

Table 4. Number of nuclear reactors and associated capacities in construction, planned, and proposal stages across Member States, GW-scale projects only

	Construction		Planned		Proposed	
Member State	Reactors	Capacity (GW)	Reactors	Capacity (GW)	Reactors	Capacity (GW)
Belgium					4	4
Bulgaria			2	2.5		
Czechia			5	5	2	0.6
France					6	9.9
Hungary	1	1.2	1	0.8		
Netherlands					4	
Poland			3	3.7	2-4	3-6
Romania					2	1.4
Slovakia	1	0.5			1	1.2
Slovenia					1	1.2
Sweden			2	2.5		

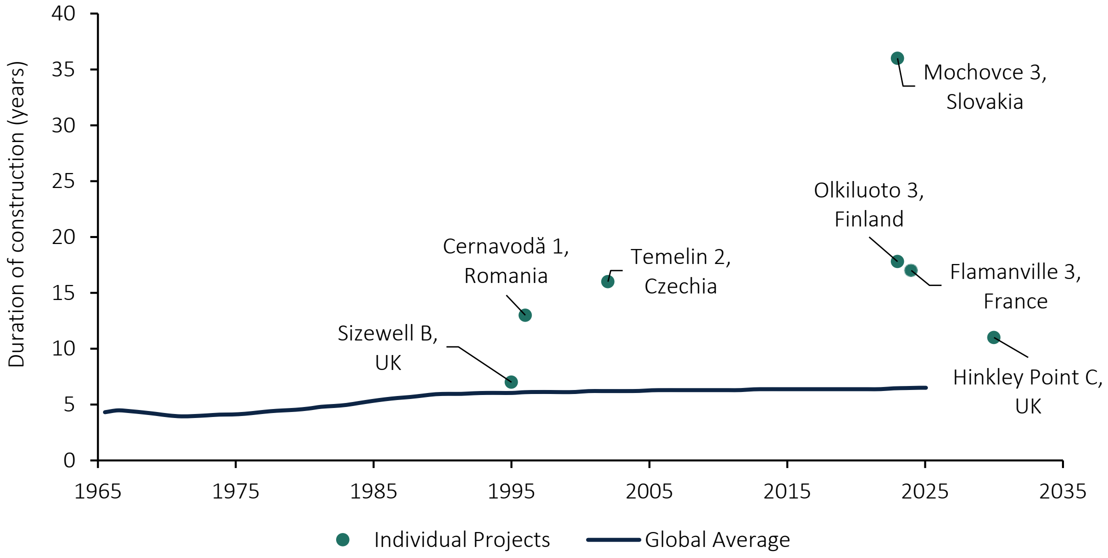
Source: authors' composition.

Recent European newbuilds have also experienced substantial schedule overruns. Beyond their inherently relatively long construction periods, nuclear projects frequently exceed initial delivery schedules, often by a factor of 2 to 3 in OECD countries. In contrast, newbuilds in some non-European contexts are now typically delivered in 5-7 years. For reactors in Europe whose construction began after 2000[42], average construction times

[42] Corresponds to Olkiluoto 3 (Finland), Flamanville 3 (France) and Hinkley Point C (UK) only.

reached around 15.3 years[43] – well above the global average of 6.5 years (Figure 12), although the IEA (2025c) provides a more optimistic range of European construction timelines of 8 to 12 years. Exceptional cases, such as Mochovce-3 in Slovakia, have taken as long as 36 years[44]. This challenge extends to other OECD economies, including the US and Japan.

Figure 12. Average global and recent European project construction period of reactors from 1965 to 2025



Source: authors' composition. Data from Global Energy Monitor (2025b), EDF (2025), World Nuclear Association (2025a), IAEA (2026b-e). Dataset available in the Supplementary Information.
Note: Hinkley Point C construction has not been completed. EDF (2025) expects operations to begin in 2030.

These delays are a major contributor to cost overruns in European projects compared with non-OECD ones, as presented in Table 5.

Lengthy construction periods and frequent schedule overruns remain significant challenges for nuclear deployment in comparative perspective as well. While the value of nuclear energy as a source of large volumes of dispatchable low-carbon electricity is well established (section 2.1), nuclear projects in Europe have been exposed to construction and financing risks over substantially longer periods and often at another order, increasing investor uncertainty regarding project delivery and final costs. Renewable energy projects are also not immune to delays or cost escalation, particularly where permitting, grid

[43] Considers the length of time between the start of construction and grid connection. Does not consider pre-construction timelines. End of construction refers to 'first grid connection' data as indicated in the IAEA's PRIS (Power Reactor Information System).

[44] Mochovce 3 began construction in 1985 and was paused in 1991 because of a lack of funds. Construction was resumed in 2008, and commercial operation began in 2024.

connection, or supply chain constraints arise. However, utility-scale PV projects typically require around 4 years, and offshore wind projects up to 11 years when the full project cycle, including development, pre-construction, and construction, is considered (SolarPower Europe, 2023; ORE Catapult, 2023)[45]. This makes full project processes for renewable projects often more predictable in Europe and arguably more attractive for investors.

Table 5. Initial and final overnight construction costs of the newest nuclear power plants in Europe compared with recent non-European projects

Project	Initial cost (EUR/kW)	Final cost (EUR/kW)
Hinkley Point C, UK (2031)*	8 900	17 300
Mochovce 3 & 4, Slovakia (2025)**	3 800	7 000
Flamanville 3, France (2024)	3 100	11 000
Olkiluoto 3, Finland (2022)	2 900	7 200
Vogtle 3 & 4, USA (2021)	6 900	15 700
Shin-Kori 3 & 4, South Korea (2015)	2 100	2 800
Barakah 1-4, UAE (2024)	6 200	7 100
Taishan 1 & 2, China (2019)	2 300	3 700
Sanmen 1 & 2, China (2018)	2 300	3 600

Note: * denotes projections for an incomplete project, ** denotes reactor of a non-OECD design. All EU reactors are EPRs except for the Mochovce 3 & 4 reactors (VVERs of Russian design). All other reactors are EPR/APR/AP reactors. Methodology adapted from IEA (2025c) complemented by data from Rothwell (2022), IEA (2022b), NEA (2020), US Department of Energy (2024b), IEEFA (2023), Power Technology (2024), EDF (2022, 2024).

The low level of recent construction activity has contributed to 'negative learning' and 'forgetting-by-doing[46]' (Lovering et al., 2016). In turn, this has further weakened Europe's nuclear industrial base and its ability to deliver newbuild projects that are relatively efficient and competitive (section 4.1.2). Taken together, rising costs and construction delays reflect a mix of industrial, regulatory, political and market factors.

[45] Depending on the project scale and type, hydropower plant construction can also involve construction periods of close to 10 years (IRENA, 2015).

[46] This contrasts with the more conventional terms 'positive learning' and 'learning-by-doing', typically attributed to technological learning curves.

First, the lack of standardisation across reactor designs and the increasing technological complexity of Generation III+ reactor designs, accompanied by heterogeneous regulatory procedures across the EU, have constrained efficient deployment. Project planning and design maturity have also played an important role. Several recent projects in the EU and the US began construction with a lower degree of design maturity, leading to design modifications as construction moved on and, in turn, unforeseen cost overruns and delays in project delivery.

Second, regulatory requirements have also become more demanding, with the successive strengthening of safety standards, particularly after Fukushima Daiichi (2011). Increased regulatory complexity, including lengthy licensing, environmental permitting, and site authorisation procedures, combined with limited harmonisation across Member States, has contributed to the extension of timelines and created additional uncertainty. The balance between necessary prudence and excessive procedural burden – and the risk of systemic paralysis – is increasingly debated.

Finally, political reversals of national energy strategies across Member States have also emerged as a material risk factor (section 1), as discussed inter alia in the report published by the French Parliament in March 2023.

As a result, project delays and cost overruns have involved greater financial risks for investors and therefore shifted nuclear investments towards increasingly higher risk profiles, raising financing costs and weakening the bankability of new nuclear projects, as discussed in section 4.2 (Weibezahn and Steigerwald, 2024).

Reversing these trends will depend on rebuilding industrial delivery capacity. First, well-functioning EPC consortia are central to this process (section 4.1.2). More broadly, a sustained nuclear orderbook and advancement towards serial deployment are often cited as key solutions for cost reduction through learning effects, while providing the industry with long-term visibility, certainty, and economies of scale, as demonstrated by China[47]. However, achieving similar learning curves in Europe remains constrained by the limited pipeline of projects, which limits economies of scale in manufacturing and construction (Rothwell, 2022).

Second, European cost overruns have been particularly associated with recent European Pressurised Reactor (EPR) projects. EDF is now planning to rebuild its execution capacity through its domestic programme of six EPR2 reactors. The expectation is that a credible learning curve can be achieved across these successive projects, potentially breaking the

[47] China has reduced the overnight cost of newbuilds from >8 000 USD/kW in 1994 to approximately 2 000 USD/kW in 2025. It is expected that this will further reduce to 1 600 USD/kW by 2030 (Liu et al., 2025). Refer to the Supplementary Information further details.

existing pattern of 'forgetting-by-doing'. Non-EU vendors, including Korea's KHNP, Westinghouse in the US, and Canada's Candu Energy (AtkinsRéalis), may help expand deployment capacity. However, the reliance on non-EU technologies may require a carefully calibrated approach that balances efficient deployment with broader considerations related to technological sovereignty and industrial competitiveness. Moreover, some non-EU vendors have yet to gain experience delivering newbuild projects within the European regulatory and market context.

SMRs are often presented as a potential means of mitigating some of the time- and cost-related risks associated with GW-scale projects through modularity and potential for serial manufacturing. However, these advantages remain contingent on successful FOAK deployment and standardisation (section 5).

4.1.2. Rebuilding the EU's nuclear supply chain

The nuclear energy supply chain is widely recognised as one of the most complex industrial supply chains and can be broadly divided into six tiers, as shown in Table 6 (Deloitte, 2025). Compared with many other regions actively pursuing nuclear deployment, the EU retains capabilities across most segments of the nuclear supply chain. Yet, the scale of the challenges shall not be underestimated: rebuilding and scaling up supply chains, which have been weakening over decades, will require sustained investment, stable project pipelines, and long-term policy commitment.

Securing a competitive and resilient European nuclear supply chain is not only essential to deliver a new wave of nuclear projects at scale but also should be seen as part of a broader agenda to strengthen EU industrial competitiveness. Nuclear's advantages as 'homegrown' energy and a high-value-added industrial sector could contribute to strengthening EU strategic autonomy (Eurelectric, 2024; JRC, 2025).

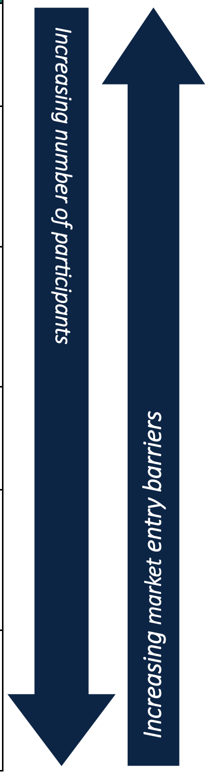
Technology vendors and system integrators

Tier 1 and 2 suppliers comprise reactor technology vendors, system integrators and EPC contractors. Often, these services are 'bundled' and include, in various combinations, engineering, fuel fabrication, O&M, and spent fuel solutions. At these tiers, stringent regulatory requirements and greater technical complexities may result in an increasing presence of market-entry barriers and constrain supplier profitability (Deloitte, 2025). Together with the sector's own structure (i.e. the prevalence of state-owned enterprises (SOEs)), this results in a limited number of technology vendors globally. Greater market participation is found towards the lower tiers.

Given the high degree of interdependence across supply chain tiers, nuclear projects have often been developed through an integrated 'turnkey' format, where a single contract delivers the design, EPC, and nuclear power plant commissioning in its entirety (JRC, 2025). This allows for the streamlining of different supply chain segments in a vertically integrated format. Vertically integrated supply chains can result in cost reductions by avoiding double marginalisation[48] (JRC, 2025).

Table 6. Tiers in the nuclear energy supply chain

Tier	Participant	Description/Examples	Present in the EU?
1	Technology vendors	Nuclear steam supply system	✓
2	System integrators	Reactor pressure valve, steam generator	✓
3	Original equipment manufacturers (OEMs)	Rod cluster, control assembly, tube bundles, etc.	✓
4	Sub-component suppliers/distributors	Control rods, heat transfer tube, etc.	✓
5	Processors/fabricators	Complex alloy, thermally treated alloy 690, etc.	✓
6	Raw material suppliers	Mining activities, e.g., silver, zinc, iron ore, nickel, etc[49].	



Source: authors' composition, adapted from Kaser (2014) and JRC (2025).

Although integrated vendor-EPC models remain common (e.g. EDF, Rosatom and KHNP), particularly for their domestic projects, unbundled procurement models are also increasingly used as an alternative, with growing interest in the EU in exploring more diversified contracting approaches. Under these models, employed, for example, by US Westinghouse, reactor vendors and EPC contractors are procured separately, often through consortia arrangements. While this approach can facilitate greater localisation and can improve transparency and potentially therefore cost control, it may also increase

[48] Double marginalisation is a form of market inefficiency in which participants in the same supply chain each add their own markups, causing the final price to be higher than through coordinated pricing.

[49] While mining activities as such are confined to actors outside the EU, uranium recovery as a by-product of zinc and nickel started in Finland in 2024, to reduce dependence on external actors.

project complexity and interface risks[50]. Conversely, the attractiveness of the 'turnkey' model should not be underestimated. For instance, Rosatom's build-own-operate model – financed through Russian government-backed loans and allowing the government to retain part or most of the project revenues – has proved attractive in emerging markets such as Bangladesh, Egypt and Turkey.

The number of technology vendors available on the EU market has undergone a substantial transformation in recent years. With Russian and Chinese vendors effectively excluded, the pool of available suppliers is largely restricted to French EDF, US Westinghouse and GE Vernova Hitachi, Korean KHNP, and Canadian AtkinsRéalis.

EDF's EPR2 technology was originally expected to become a flagship European design. However, the technology faced setbacks, with cost overruns and delays both in Europe and overseas. While difficulties linked to FOAK learning curves partially explain these outcomes, policy and industrial decisions also played a role. Building isolated projects across different countries meant effectively creating a new FOAK project each time, without a clear follow-on pipeline and with limited opportunities to establish learning curves and improve efficiency and performance from one project to the next. In 2026, France confirmed the decision to build six EPR2 reactors domestically – which could become an important test case. If implemented successfully, it could unlock a 'fleet effect', allowing for the deployment of the EPR2 design in a gradually cost-effective manner. This can also have positive effects on the techno-economic and industrial viability of the French (and broader European) nuclear industry.

In parallel, growing interest in non-EU vendors has become increasingly evident. Atkins Réalis' reactor technology (CANDU), historically operational in Romania, is planned for a new unit in Romania and is being considered for Poland's second nuclear power plant. KHNP and Westinghouse have been awarded the contracts for the Czech and Polish nuclear power plants, respectively. Following the settlement of their intellectual property dispute, Westinghouse and KHNP reached a broader agreement under which KHNP withdrew from several European tenders, including those in Slovenia, Sweden, and the Netherlands. Instead, Westinghouse cooperates with Korean EPC companies such as Hyundai E&C on European projects.

As a result, the already limited global vendor competition has become further narrowed down in Europe. This may further constrain procurement options and reduce competitive

[50] Like many other OECD project developers, Westinghouse has experienced significant cost overruns and delays. Upfront capital expenditure for Vogtle Units 3 and 4 (Georgia, US) exceeded USD 30 billion and were delivered with a delay of 7 years (IEEFA, 2022).

pressure on project costs. The emerging SMR segment may offer a more diverse vendor ecosystem, potentially allowing for greater competition (section 5).

Nuclear-grade components and obsolescence of systems, structures and components

All tiers of the nuclear supply chain are subject to stringent quality assurance requirements, guaranteeing the highest levels of safety across all components. Components used in nuclear facilities are required to meet nuclear-specific standards, commonly referred to as *'nuclear-grade',* which significantly exceed those typically applied in 'industrial-grade' or 'commercial-grade' components.

One frequently cited bottleneck concerns *reactor-specific components* – large-scale and ultra-large-scale forgings required for constructing primary circuit[51] components, such as containment and reactor vessels, turbine rotors, and steam generators. Today, much of the global larger-scale forging production is concentrated in Russia and Asia (JRC, 2025; CATF, 2025a). Although forging capabilities are present in France, Germany and Italy, these may not be sufficient to cater for the future domestic demand, especially if SMRs are to be developed at scale. SMRs may, however, depend on smaller-sized components which are easier to procure, and may benefit from greater market competition (JRC, 2025). In principle, it is not necessarily problematic for some forging capacity to remain outside the EU, given that such components are procured only once during reactor construction, and once delivered, reactors remain in operation for at least 60 years.

More significant supply chain risks arise from components that require periodic replacement throughout a reactor's operating lifetime. Supply chain challenges are particularly acute for systems, structures and components (SSCs) required for existing reactors, which may need exact replacement parts but are increasingly encountering obsolescence of SSCs (Lee et al., 2022). Because of the continuous evolution of nuclear safety standards, requiring best available technology (BAT), but also because of decades of limited new nuclear construction[52], many tier 2 and tier 3 participants, particularly original equipment manufacturers (OEMs), have either exited the sector or shifted towards other industries, thus no longer providing nuclear-grade components. Simultaneously, high market entry barriers have discouraged new suppliers from entering the stagnating European supply chain market, leading to a considerable drop in ASME N-type[53] component supplier companies operating in Europe (Foratom, 2020). Cross-sector

[51] The primary circuit of a nuclear power plant, also known as the nuclear island, is the section of the reactor where the nuclear chain reaction takes place (ENEC, 2024).

[52] Industrial activities have largely been confined to O&M rather than the manufacturing of components. There has not been a large enough market in place for supply chain participants to pursue.

[53] The American Society of Mechanical Engineers (ASME) issues N-Type certificates for nuclear reactor components, including vessels, pumps, valves, piping systems, storage tanks, core support structures, concrete containments, and

competition adds complexity as suppliers of high-specification materials often serve multiple industries, including aerospace and defence, resulting in increased lead times and pricing pressures.

As a result, nuclear power plant operators increasingly face SSC obsolescence. These challenges become particularly pronounced during LTO, where replacement components may no longer be commercially available because of discontinued production by OEMs or because suppliers no longer meet stringent nuclear quality assurance standards. Maintaining an integrated reactor supply chain has proved challenging for the industry. This is the case even for EDF, which operates a large fleet of standardised reactors and maintains dedicated stocks of SSCs for maintenance purposes.

To address these challenges, nuclear power plant operators increasingly resort to commercial-grade dedication (CGD), a process that involves reverse engineering or requalifying industrial-grade components for use in nuclear applications. While CDG expands the pool of potential suppliers and mitigates some supply chain constraints, gradual reliance on CGD also underscores the erosion of Europe's dedicated SSC manufacturing base and increases concerns regarding the consistency and stringency of safety regulations as well as the feasibility and safety of LTO strategies across Europe's nuclear fleet. In addition, the broader decline in European heavy industry, including steel production, may have implications for the long-term resilience of the nuclear value chain.

Regulatory fragmentation further complicates supply chain development. Reactor licensing remains a Member State competence, requiring vendors to adapt designs to national regulatory requirements and criteria. The absence of greater harmonisation limits standardisation; that is, one reactor may be approved in one Member State but require alterations for approval in another, ultimately becoming a bottleneck to streamlining supply chain processes, adding costs and inhibiting economies of scale from being achieved. Greater collaboration and harmonisation of supply chain requirements among Member States, such as the recent deal between the UK and the US, are increasingly viewed as an important enabler of supply chain development. Achieving greater harmonisation will be particularly important, especially for SMRs, as their success in streamlining will depend heavily on standardised designs.

transport packaging. While N-type certification is not a requirement in the EU (reactor licensing depends on national competent authorities), this provides an indication of the shrinking nuclear supply chain.

Industrial policy and public support

Rebuilding Europe's nuclear supply chain is widely recognised as a structural challenge. Decades of limited construction activity have eroded industrial capabilities and reduced the sector's ability to deliver projects at scale. Addressing these constraints will require sustained investment, long-term visibility for suppliers, and supportive policy frameworks.

A recent shift occurred as nuclear became increasingly embedded in broader EU industrial policy debates. During the previous political cycle, the latter gained a strong impetus in response to global competition pressures, most notably the US Inflation Reduction Act (IRA). The EU's principal response, the NZIA, aims to strengthen the EU's cleantech manufacturing base by targeting 40% of EU manufacturing to be produced domestically by 2030.

The Commission's original proposal (2023) did not explicitly position nuclear technologies as a central pillar of the net-zero industrial framework. The decision arguably reflected both political sensitivities surrounding nuclear and the intention to prioritise technologies considered more immediately scalable. In the final agreement on the NZIA, nuclear fission technologies and parts of the fuel cycle were included within the scope of net-zero technologies. They can qualify as 'strategic projects', benefitting from enabling measures such as simplified permitting procedures and access to support from Member States and, where applicable, EU instruments.

The level of industrial support, however, remains fragmented and largely dependent on the national priorities and fiscal capacities of individual Member States. State aid frameworks and IPCEIs remain, in principle, among the most feasible pathways for supporting nuclear supply chains. The IPCEI on Innovative Nuclear Technologies (Innovative Nuclear Technologies), announced by the 13 Member States in April 2025, focuses on R&D and therefore does not address the broader challenge of scaling industrial manufacturing capacity. While IPCEI-type approaches could support nuclear supply chains in a similar way to their application in the battery and hydrogen sectors, the overall scale of support remains limited.

Nuclear technologies still lack a dedicated EU industrial policy framework comparable to the multilayered framework developed in the US, which combines loans and tax credits covering up to 50% of capital costs, production tax credits, and institutional partnerships. Replicating the US approach directly in the EU context is not feasible, given existing legal and institutional constraints. Consequently, alternative approaches will need to be developed, drawing on lessons from other strategic industrial sectors.

Access to EU funding for nuclear technologies remains selective and uneven across programmes, reflecting both institutional design and eligibility constraints.

- R&D&I remains relatively modest. The *Euratom Research and Training Programme* remains the core dedicated EU funding instrument for nuclear, covering fission safety, radiation protection, waste management, and fusion research. However, its budget remains limited compared with other EU funds. Under the 2026-2027 Work Programme, the Euratom research budget allocates approximately EUR 108 million to fission for areas such as the safe management of radioactive waste, radiation protection, and innovation in nuclear materials, still representing a relatively small contribution.

- *Horizon Europe* focuses on R&D&I, with a strong focus on resources for fusion research. In accordance with Article 4 of the Euratom Treaty and its Annex 1, the main research and development areas relevant to the nuclear fission sector remain the exclusive prerogative of the Euratom Programme (unlike fusion, which can access both programmes). As a consequence, Horizon Europe can only finance cross-cutting aspects of nuclear research, limiting its support to the safe and secure use of non-energy applications of ionising radiation in sectors such as medicine, industry, agriculture, space, climate change, security and emergency preparedness.

- *InvestEU* provides EU-backed guarantees to mobilise private investment. Nuclear-related allocations remain limited, although the SMR Strategy (2026) recently announced that, for the first time, the Commission will consider an additional temporary InvestEU top-up of EUR 200 million until 2028. This would be to further support the deployment of the initial commercial units of innovative nuclear technologies, including LW-SMRs, AMRs, MRs and fusion, within the EU.

- *Innovation Fund (IF)* (financed through Emissions Trading System (ETS) revenues) is technology-neutral in principle but primarily oriented towards demonstration-scale low-carbon technologies with industrial applications. Although nuclear projects in principle may be eligible, the track record has not been successful, and certain barriers to meeting eligibility criteria remain, as noted by stakeholders.

Taken together, existing EU instruments provide targeted support for research, innovation and potentially selected deployment activities, but fall short of a comprehensive industrial strategy capable of rebuilding Europe's nuclear supply chain at scale. Consequently, the pace of public support for supply chain expansion continues to depend largely on Member State policies.

4.1.3. Workforce and skills

The nuclear industry remains an important contributor to the EU economy. In 2025, it generated EUR 251 billion and sustained over 880 000 jobs annually, of which 135 000 are direct jobs (Deloitte, 2025). Employment spans the entire value chain, including construction, operation, LTO, and decommissioning, as well as additional activities such as R&D and induced jobs.

Looking ahead, workforce demand is expected to increase. The 8th PINC (2025) projects that the sector can support more than 1.12 million jobs across Europe, with an annual economic impact of EUR >256 billion annually[54]. This growth is driven by several parallel trends: (i) expectations of construction of newbuilds, (ii) increasing LTO of existing plants, (iii) decommissioning activities of the increasingly ageing fleet[55], (iv) expanding R&D activities across the whole value chain, and (v) the advancement of new technologies, including SMRs and AMRs. Similar trends are already visible in the UK, where the industry now sustains a record-high workforce of 98 000 employees (NIA, 2025).

Yet, to realise the sector's growth in both employment and economic impact, a substantial renewal of the workforce is required. Workforce constraints are among the most acute risks for the European nuclear sector. Decades of stagnation, combined with the persistent public framing of nuclear as a declining and unattractive sector, significantly reduced the inflow of new talent. Anticipated large-scale decommissioning plans in several Member States further decreased the attractiveness of long-term career commitments in the field.

As a result of limited investment and stagnation in hiring from the 1980s to the early 2000s, Europe now faces a generational gap in experienced staff and leadership capable of delivering large-scale projects (ENS, n.d.b). Much of the current EU workforce was recruited during the major deployment wave of the 1970s and 1980s. As these employees approach retirement, significant knowledge and experience risk being lost unless supported by targeted recruitment, training and re-skilling programmes (SNETP, 2025).

Simultaneously, short- to medium-term technological developments, such as SMR and Gen IV reactor deployment, utilisation of advanced fuels, and the introduction of artificial intelligence (AI) in reactor operations (ENS, n.d.b), will require new expertise beyond the

[54] Values calculated from interpolating data from European Commission (2025a) and Deloitte (2025), assuming linearity.

[55] Most nuclear reactors in OECD economies operate under 40-year licences, and the average age of these reactors is 36 years (IEA, 2025c). Hence, a growing number of reactors will start their decommissioning stages unless they enter lifetime extensions.

conventional skillsets long present in the sector. Investment in ensuring a sufficiently large and skilled workforce is becoming a precondition for the sector's long-term success.

Skills shortages are particularly evident in licensing, project management, and nuclear-specific I&C activities. These competences are either scarce today or face strong competition from other industries (ENS, n.d.b), which may appear more attractive for younger generations to join. In some Member States, recruitment challenges are further compounded by concerns over long-term job security due to project cancellations, delays, and irregular political or governmental positions towards nuclear energy, including proposed phase-out plans that have later been halted or reversed.

These shortages are not merely for the future. Workforce and skills constraints have already contributed to project delivery challenges. For instance, welding and quality control issues have been cited as major causes of delays and cost overruns in EPR projects. Even in France, staff turnover is rising, and attracting and training new generations is proving difficult. The shortage of qualified personnel extends beyond nuclear sector roles and affects broader industrial and technical domains. Shortage is especially critical in project management, radioprotection, civil engineering, mechanical assembly (notably welding), and electrical systems.

Importantly, these shortages are not unique to the nuclear sector. They reflect EU-wide labour market challenges across high-tech and heavy industry. However, nuclear often competes poorly against other sectors in terms of career visibility, mobility, and perceived stability. Without proactive, targeted policies, the industrial and technical bottlenecks risk amplifying workforce bottlenecks. This challenge is particularly relevant for Member States starting their nuclear programmes, where it is pivotal to start adequate and coordinated planning for nuclear staffing (both at the national and European level, leveraging existing competencies in other countries), as this process requires several years to develop.

Actions to support workforce development currently include, among other things, Euratom-funded education and training programmes, such as the Skills4Nuclear (S4N) aimed to convene industry, research and education (SNETP, 2025), the creation of the European Human Resources Observatory for the Nuclear Sector (EHRO-N), initiatives led by Nuclear Societies incorporating Young Generation communities, and targeted efforts by the nuclear sector to improve the attractiveness of careers in the nuclear industry. However, achieving the scale of deployment currently envisaged for both GW-scale reactors and SMRs will require far more sustained investment in human capital and long-term workforce planning.

4.2. Financing new nuclear

This section analyses financing structures for new nuclear projects in Europe. Section 4.2.1 first explains how the high upfront capital requirements of GW-scale nuclear projects and long construction timelines, together with regulatory and policy uncertainty, have significantly constrained private capital participation. It then discusses the implications for capital structure, including continued reliance on public ownership and state-backed financing, and outlines the need for comprehensive de-risking mechanisms. Section 4.2.2 reviews the main risk-sharing instruments currently used or proposed in the EU to enable nuclear investment.

4.2.1. Financing constraints and capital structure

The high fixed-to-variable cost ratio of nuclear projects (section 3.1) means that, while substantial upfront investments may be offset by low and stable operational costs over several decades, securing the required (often two-digit billion) capital remains a major barrier to deployment (World Nuclear Association, 2025b). Nuclear newbuilds have, in some cases, involved upfront investments exceeding EUR 25 billion (EDF, 2024), making them too large for conventional project financing and limiting their attractiveness to private financial institutions.

High overnight costs are themselves a major structural deterrent to private investors. In Europe, this challenge is further aggravated by extended construction timelines, frequent and substantial cost overruns, lengthy and complex regulatory and permitting processes (section 4.1), uncertainty surrounding national and EU nuclear policies (section 1) and nuclear's future under the EMD (section 3.2). Financing costs are highly sensitive both to construction risks and to the expected revenue streams (IEA, 2025c). Together, these factors increase financing risk and make long-term, multi-billion-euro investment commitments particularly difficult.

The capital structure of nuclear projects typically combines both equity[56] and debt[57] financing. For GW-scale reactors, equity financing remains the most common pathway because of the elevated risks associated with construction. Financial institutions are usually less willing to participate in projects involving high upfront costs and significant construction risks (Weibazahn and Steigerwald, 2024). In the case of LTOs, debt financing

[56] Equity financing involves an investor providing funding in exchange for a stake in a project. In the case of SOEs, this can be state fund investments.

[57] Debt is capital borrowed from third-party financial institutions, usually involving interest rates. Debts can involve direct loans and loan guarantees.

typically dominates, as sunk costs of existing assets substantially reduce exposure to construction risk, making these projects generally more bankable.

Public support

Nuclear development has historically relied on public capital, although the degree of state involvement varies across countries. In Europe, this is unlikely to change fundamentally in the near term: nuclear power plants are long-lived strategic assets with operational lifetimes of at least 60 years, with the need for sustained public or state-backed financial support.

Compared with the more privately-owned model in the US, the nuclear sector in Europe remains largely dominated by SOEs, which are responsible for building and/or operating the power plants. The European model reflects the high capital intensity, long investment horizons, strategic importance, strict safety enforcements, and the historically strong involvement of the public sector in electricity (IEA, 2025c). SOEs are typically more capable of leveraging large amounts of capital at more competitive rates and absorbing costs and risks associated with new multi-billion-euro projects.

Given their complexity, nuclear projects often struggle to gain traction without government backing. This is especially critical for FOAK designs and for projects in Member States kick-starting their first capacity additions, which may entail additional costs (IEA, 2025c). In this regard, de-risking instruments and certain public support will remain important, mostly borne by Member States.

At present, EU-level funding and de-risking instruments remain limited at best. The EIB has historically taken a cautious approach to nuclear financing, with only limited involvement largely restricted to safety upgrades or decommissioning-related activities. However, the recent EUR 400 million loan agreement between the EIB and Orano to expand the Georges Besse enrichment facility in France is a positive step towards greater EIB involvement in de-risking nuclear investment. While stronger EIB involvement is essentially welcome, the constraints associated with its mandate are unlikely to be easily resolved. More positive externalities may be potentially awaited thanks to more positive engagement in nuclear by the World Bank and some international development banks. Similarly, EU funding mechanisms have often excluded nuclear. The Just Transition Fund explicitly excludes the construction of nuclear power plants from its scope, while the eligibility of nuclear investments under the Modernisation Fund, financed through revenues from the ETS, remains contested.

In comparison, the US, through a combination of federal funding, regulatory reforms, loan guarantees, and technology-neutral tax incentives, has sought to mobilise substantial private investment in nuclear technologies (CSIS, 2025; US Department of Energy, 2023).

Greater emulation of the US approach, where significant capital flows into new nuclear projects, startups, and SMRs, driven predominantly by private sector dynamics, could be beneficial.

So far, in the EU, Member States will remain to bear the core burden of public support for nuclear energy. Yet public financing alone is unlikely to be sufficient, as fiscal constraints, competing policy priorities, and the scale of investment required will inevitably limit the extent of public support available. As a result, there is a broad consensus that private capital will need to play a significantly larger role in future nuclear deployment.

Private capital

At present, however, private capital participation in nuclear projects in Europe remains limited, particularly among financial institutions, investment banks and investment funds. This raises important questions regarding the barriers constraining private investment and the types of support instruments needed to enable greater private participation. Despite repeated outreach efforts during this research, engagement from financial actors remained limited. This may also indicate a need for further work to improve the financial sector's understanding of the specificities of nuclear projects, whose risk profile differs substantially from that of most infrastructure investments and therefore requires tailored financing approaches.

Attracting greater private investment in newbuilds will also depend on the industry's ability to demonstrate credible delivery performance in terms of costs, construction timelines, and technology maturity (section 4.1). Only by establishing such credibility can nuclear projects expand their borrowing capacity from private financial institutions and improve borrowing conditions (Weibazahn and Steigerwald, 2024).

Political uncertainty and regulatory complexity also remain important deterrents. Multi-billion-euro investments are highly sensitive to policy stability. Although the EU political discourse has become more supportive of nuclear energy in recent years, inconsistencies across EU policy and regulatory frameworks persist (section 1.3). Among other things, the transitional treatment of nuclear energy under the Taxonomy creates strong private investment reluctance (Box 6). Private investors are unlikely to commit to highly capital-intensive projects expected to operate for more than six decades when regulatory frameworks consider these assets temporary.

Finally, uncertainty over nuclear's long-term revenue adequacy and broader uncertainty regarding the future role of nuclear under the current EMD (section 3.2) remain additional factors constraining private investment. Long-term revenue visibility is therefore becoming increasingly important for securing financing at competitive rates.

Box 6. Horizon of planning: the EU Taxonomy

The EU Taxonomy defines criteria for environmentally sustainable economic activities under the principle of 'do no significant harm' (DNSH). The Taxonomy classifies nuclear as a 'transitional activity', thus not labelled as sustainable in the pure sense. Following extensive political and legal debates over 2018-2021, the Commission finally included certain nuclear activities in the Complementary Climate Delegated Act (2022).

Eligible nuclear-related activities include:

- advanced technologies with a closed fuel cycle (i.e. Gen IV) to incentivise research and innovation into future technologies in terms of safety standards and minimising waste
- new nuclear power plant projects for energy generation, which will be using BAT (Gen III+), to be recognised until 2045 (date of approval of construction permit)
- modifications and upgrades of existing nuclear installations for LTO that will be recognised until 2040 (date of approval by the competent authority).

These activities are subject to stringent criteria, including compliance with nuclear and environmental safety standards, as well as waste disposal regulations. SMRs are not explicitly listed – their eligibility depends on meeting the same criteria as other technologies, including compliance with the DNSH.

The Taxonomy explicitly excludes nuclear fuel cycle activities: processes involved in the production and management of nuclear fuel, such as mining, enrichment, and reprocessing. The exclusion of nuclear fuel cycle activities is particularly sensitive at a time when substantial investment is required to diversify fuel supplies away from Russia. Additionally, promoting Gen IV reactors, the Taxonomy does not recognise the very fuel cycle facilities needed to support their deployment, including reprocessing and recycling (which already, besides Gen IV, offer strong benefits in terms of waste management).

The Taxonomy sets an explicit cut-off date (31 December 2045) for new nuclear plants to be eligible under the framework: the '*sunset clause*'. The presence of the sunset clause means that construction permits must be granted by 2045 for new nuclear plants to qualify as a 'sustainable investment'. Nuclear plants with permits after 2045 will not be considered eligible.

The sunset clause introduces long-term uncertainty for investment planning in newbuilds. These projects may find it harder to attract investors seeking taxonomy-compliant portfolios. Without a long-term strategy and vision, the nuclear industry faces increasing exposure to investor reluctance. Periodic revisions of the EU Taxonomy tasked to the Commission provide an opportunity for the regulatory clarity needed to unlock public and private investment.

4.2.2. Risk allocation and de-risking instruments for newbuilds

Given the scale and duration of nuclear investments, risk-sharing mechanisms remain central to financing newbuild projects. These typically take the form of horizontal risk-sharing arrangements, with the purpose of reducing the political, regulatory, construction and market risks borne by project developers and operators, thereby improving bankability and lowering financing costs.

Political and regulatory risks are central to highly capital-intensive investments that require political and regulatory predictability over relatively long construction and operational periods. *Construction risks* refer to the risk of cost overruns, delays, and technical underperformance during the construction phase, which remain a dominant bottleneck, as the risk burden in many cases rests primarily with developers, and ensuring financing during the construction phase may become particularly challenging. *Market risks* include revenue risks in terms of both electricity prices and sales volumes. Long-term revenue visibility is essential to secure financing and reduce the cost of capital.

Across Europe, various risk-sharing strategies are being explored through different state aid approaches (Box 7), presented as various state aid options but remain works-in-progress, and more robust ones are still needed. The most developed approaches currently exist in the UK and prospectively in Sweden.

In practice, existing financing frameworks typically combine three categories of instruments:

- *construction risk mitigation* through state-backed guarantees, loans or RAB
- *price risk mitigation* through CfDs or other similar options
- *volume risk mitigation* through long-term offtake structures, such as PPAs, potentially supported by Carbon Contracts for Difference (CCfDs), subject to eligibility and design.

Price risk mitigation: CfDs

In order to reduce revenue volatility, the 2022-2024 EMD reform has recognised CfDs, potentially combined with PPAs, as a default instrument for price stabilisation, although equivalent instruments may also be considered. Subject to State aid approval by the Commission, CfDs have already been applied, approved, or proposed for several newbuilds. Hinkley Point C in the UK[58] was the pioneering one. CfD schemes have been approved in Czechia and Poland (Box 8), submitted for State aid approval by France, or are being considered and negotiated (the Netherlands and Sweden).

Despite their growing role, several issues should be noted.

First, CfDs are primarily designed to stabilise operational-phase revenue streams for low-carbon projects. While the State aid decisions for nuclear projects in Czechia and Poland have approved durations of up to 40 years, CfDs cover only a fraction – albeit a major one – of the asset's lifetime (60 years or longer). This may create uncertainty regarding exposure to market prices once the CfD period ends. In addition, long lead times between investment decisions and commercial operation create further uncertainty regarding the appropriate strike price to be set, an issue that individual CfD decisions increasingly seek to address through project-specific design.

Box 7. EU State aid for nuclear projects

EU State aid refers to any financial support granted by a government or public body to companies. In principle, EU State aid is prohibited under the TFEU unless it is approved by the Commission. For EU State aid to be approved, a measure notified by a Member State must undergo a formal investigation against qualifying criteria, including: guarantees that the project is of common interest; assessments of the project's viability without State aid intervention; and whether the project does not establish unfair disadvantages within the EU internal market.

Support schemes for nuclear energy, including CfDs, fall under these rules and require prior approval. Several nuclear projects have already been assessed under the State aid framework, including Hinkley Point C in the UK, Dukovany II in Czechia, and Lubiatowo-Kopalino in Poland.

[58] Hinkley Point C's State aid was approved in 2014, before the UK's withdrawal from the EU.

The length of the State aid approval process has been consistently identified by stakeholders as one of the key factors affecting investor confidence. The approval of Dukovany II State aid took over two years (European Commission, 2024). While improvements have been made for Poland's Lubiatowo-Kopalino – reducing decision times to just over one year – accelerating this process would be key to maintaining investor interest in projects. This is especially the case if multiple State aid applications from multiple nuclear power plants are to be submitted simultaneously, and similar financial schemes have already been approved by the Commission.

The length of the assessment is partially explained by the procedures usually applied to State aid cases. State aid procedures typically involve two stages: a preliminary (Phase I) assessment and, where concerns remain, an in-depth (Phase II) investigation. To date, nuclear newbuild projects have generally required Phase II investigations, reflecting their scale, complexity, and potential market impact. While Phase II investigations extend timelines, they also strengthen the legal robustness of Commission decisions and reduce the risk of successful legal challenges by third parties, which, if pursued, will ultimately lead to much longer timeframes.

State aid notifications are prepared by Member States, usually in close cooperation with project developers. The Commission has recently issued the technology-neutral guidelines on the design of CfDs and PPAs, which in principle should facilitate preparation by Member States and ultimately speed up the approval timelines.

At the same time, while these guidelines are definitely useful, and the lengthy State aid approval process is arguably justified by the complexity of the issues involved and the need for in-depth scrutiny to ensure robustness against potential future legal challenges, this duration has been consistently reported by stakeholders as disadvantageous compared with the faster State aid approval processes for renewable technologies. The importance of a more accelerated and predictable State aid process, perhaps by drawing on experience from past projects, has been consistently highlighted by stakeholders as being of crucial importance.

Second, CfDs do not address construction-phase risks. Revenue support only begins once electricity generation starts, leaving developers fully exposed during the most capital-intensive phase of the project. For nuclear newbuilds, where a decade or more may separate investment decisions from revenue generation, this creates a significant financing challenge. This structural gap in risk allocation means that CfDs alone are generally insufficient to support final investment decisions (FIDs) for nuclear projects. The UK experience illustrates this limitation: apart from Hinkley Point C, no nuclear projects relying solely on CfDs have reached FID. Projects in Wylfa Newydd (North Wales) and Moorside (Cumbria) were cancelled partly because of this high, unaddressed risk burden, despite CfDs having been approved (Gov.uk, 2021). As a result, complementary mechanisms, such as regulated asset base (RAB) models, co-investment structures, hybrid public-private financing 'hub' models, or state guarantee loans, are increasingly considered. In Sweden, for example, a combined CfD-based framework is currently under development to address this issue (see below).

Third, CfDs create long-term financial liabilities for governments, which may, in turn, constrain political appetite for deploying them at scale. Governments may also simply lack sufficient financial resources to enter into such agreements. Therefore, a balance needs to be struck between reducing investor uncertainty and limiting public financial exposure. At the same time, CfDs for nuclear newbuilds are not necessarily more expensive than support mechanisms granted to other low-carbon technologies. Indicative strike prices for a nuclear newbuild in Poland (110-130 EUR/MWh) are largely comparable to recent offshore wind auction results in the Baltic Sea (110-120 EUR/MWh).

For these reasons, CfDs are increasingly being combined with complementary instruments that address construction and financing risks more directly.

Box 8. Case of Poland's tailored CfD

For the deployment of its first-ever nuclear power plant, Lubiatowo-Kopalino, Poland notified a State aid scheme to the Commission that adopted the CfD model to the specific risk profile of the newbuild. The initial notification included the CfD to cover the entire lifespan of operations (60 years). To make this viable, the submission endorsed both a time-dependent strike price adjustment mechanism and a load-factor strike price (LFSP) adjustment mechanism. This novel approach to CfDs was designed to protect investors against price risk and power output risk.

The time-dependent strike-price adjustment was intended to respond to changes in the power plant's revenue originating from variations in inflation, interest rates, OPEX costs, unplanned regulatory changes, etc. The frequency of the time-dependent strike price adjustment review would be periodic and agreed on by the different parties. The LFSP mechanism aimed to shield the functioning of the CfD in the context of expected operation at reduced load factors. The strike price would accordingly be lowered proportionally to the average load factor of the power plant, adapting to the reduced profits the plant operator would receive from lower power outputs. The State aid submission proposed the strike price calculation to be revised annually based on the average load factor of the preceding year. In the case of the load factor being higher than expected, the strike price would be raised following the same principles (European Commission, 2025d).

This State aid scheme has received formal approval by the Commission in late 2025, although the length of the CfD scheme has been reduced from 60 years to 40 years.

Construction risk mitigation: RAB model

The limitations of CfDs during the construction phase have prompted growing needs for complementary financing models. Among these, the RAB model, adopted for the UK's Sizewell C project (expected to become operational in the mid-2030s), represents one of the most developed approaches.

The RAB model allows developers to start recovering the invested capital during construction, rather than only after the nuclear power plant is fully commissioned. An economic regulator issues a licence to the project developer, allowing them to charge a regulated levy to customers during the construction phase (via energy bills). This distributes part of the financing risk across a broader consumer base, reducing the amount of interest on loans and lowering the project financing costs. For Sizewell C, the UK government estimates that the model could deliver savings of more than GBP 30 billion compared with a CfD-only approach, equivalent to around GBP 10 annually on household energy bills over the plant's lifetime (Gov.uk, 2021). The economic regulator monitors the cost burden on customers' bills, ensuring transparency and limiting excessive cost transfers to consumers (Stephenson Harwood, 2025).

Although the estimated impact on consumer bills during construction is relatively small – the UK model adds <1 GBP to consumer bills – questions remain regarding risk allocation and public acceptability. Ultimately, like a CfD, both models rely on cost recovery from consumers or taxpayers in one way or another. Compared to CfDs, however, the RAB model addresses one of the principal financing barriers facing newbuilds: the lengthy period between investment and revenue generation. By reducing project risk and lowering the required rate of return to be paid to the project developer, the RAB model can decrease overall project costs and reduce the public support ultimately required.

While no EU Member State has yet adopted an RAB model, the EMD allows for mechanisms with effects equivalent to CfDs, potentially creating scope for similar approaches subject to State aid approval. However, the development of such solutions to mitigate construction risks will need to be driven primarily by the private sector, including the nuclear and financial industries, rather than by EU institutions or Member States alone.

Volume risk mitigation: offtake structures and demand aggregation

In addition to price and construction risks, nuclear projects are increasingly exposed to volume risk because of potential reduction of dispatch volumes and, therefore, increasing uncertainty regarding future electricity sales on the wholesale electricity market (section 3.2). Securing demand is therefore becoming an increasingly important component of nuclear financing strategies. A general approach would include pooling electricity demand through long-term structured offtake arrangements. The Finnish Mankala model, discussed in Box 9, is one of the best-known examples.

More broadly, demand-side dynamics are becoming increasingly important for strengthening the investment case for new nuclear capacity. Expanding electricity demand remains a strong efficiency and reindustrialisation bet in the EU. Creating new sources of demand, such as through industrial electrification, hydrogen production, and the digital economy, could provide additional offtake opportunities for future nuclear projects. Likewise, private sector offtakers' interest is emerging, for example, in response to rising electricity demand from data centres, with particular interest in SMRs. However, in terms of potential demand creation mechanisms, nuclear-based products continue to face limited recognition. They are largely excluded or only partially recognised in such support schemes as the European Hydrogen Bank and the Industrial Decarbonisation Bank.

Box 9. The Finnish Mankala model

The Mankala model, used in Finland since the 1970s, is a joint venture model designed to pool economic resources to de-risk investments in capital-intensive power plants, sharing the risks to develop projects (NEA, 2024b). Under this model, a group of shareholders (typically industrial consumers and utilities) form a non-profit utility to develop and own a power plant. Shareholders cover construction costs and receive electricity from the plants' operation proportional to their holding shares (EPV, 2022; Weibazahn and Steigerwald, 2024), functioning as PPAs.

This risk-sharing model distributes the financial risk and revenues across all shareholders, creating economies of scale, incentivising the participation of lenders, improving economic efficiency in the construction process, and benefiting industrial consumers with long-term stable power prices. Unlike the RAB model, the Mankala model does not burden taxpayers with the financial risk. However, the consortium is also obliged to purchase the electricity from the nuclear power plant in question, regardless of other available options. Moreover, in the event of cost overruns, these are always covered on a proportional basis by the consortium itself.

The model has been widely regarded as successful. In Finland, approximately 40% of Finland's total electricity generation and 66% of its nuclear generation has been financed through this approach (IEA, 2023). The Olkiluoto 3 EPR implemented this principle, commissioned by a pooling of 60 offtakers (TVO, 2023).

Putting it together: Sweden's risk-sharing framework

Recognising that no single instrument can address all project risks, in 2025, Sweden introduced a new framework designed to tackle comprehensively and simultaneously construction, price, and revenue risks. The framework is limited to a total capacity of 5 GW and is eligible for both large reactors and SMRs.

The model combines three elements. First, government loans support construction financing and are to be repaid once operations begin. Second, CfDs provide revenue stability once the operational phase begins. Third, a risk- and profit-sharing mechanism protects investors against unusually low returns while granting the government a share of the gains when project outcomes exceed expectations. Periodic assessments of the company's equity returns determine whether government loan or CfD terms should be adjusted to keep returns within a predefined range (Government Offices of Sweden, 2025).

The Swedish approach presents an emerging trend towards integrated risk-sharing frameworks that combine several instruments rather than relying on a single risk-sharing mechanism, with the ultimate goal of providing a more comprehensive approach to improving bankability and attracting private investment into new nuclear projects.

5. SMALL MODULAR REACTORS

In recent years, SMRs have moved from the margins of European energy and industrial policy debates to the centre. Their appeal lies in the prospect of standardised designs, factory-based manufacturing and modular deployment, with Gen IV designs (i.e. AMRs) further expanding potential applications. However, despite growing policy and industrial interest, SMRs remain at an earlier stage of deployment, with FOAK projects in the EU expected to enter operation during the 2030s.

This section examines the potential role of SMRs in the EU. Section 5.2 outlines SMR technologies and their current state of development. Section 5.2 discusses the main enabling conditions and barriers to deployment, including technology selection, licensing, financing, supply chains, and fuel availability. Section 5.3 explores potential SMR applications. Finally, section 5.4 assesses their economics and prospects for cost reductions through modularisation and serial deployment.

5.1. SMR TECHNOLOGY

SMRs are commonly defined as nuclear fission reactors with power output capacities <300 MW[59], although some may reach as low as 1-10 MW[60] (NEA, 2024c). Historically, reactors of this size were among the first commercial reactors deployed in the 1950s, typically between 10 and 100 MW. By the 1960s, capacities grew to 100-300 MW, reaching GW-scale during the 1970s, which remains the default format today[61] (Bhowmik et al., 2024). Smaller reactors subsequently became confined to military or specialised applications, with limited or no commercial deployment.

Modern SMRs differ from the earlier designs not primarily in size, but in their emphasis on modularity, standardisation, and factory-based construction. This represents a shift away from fully site-specific engineering towards designs intended for serial production and off-site fabrication, followed by on-site assembly. In principle, this approach aims to address several of the economic and construction risk challenges associated with GW-scale nuclear projects, while enabling greater scalability and deployment flexibility. In theory, the emulation of modular manufacturing approaches from other industries could

[59] Some reactor concepts exceed the by-definition capacity. For example, the Rolls-Royce SMR concept reaches a capacity of 470 MW.

[60] SMRs with lower-end capacities, typically <20 MW, are referred to as microreactors (MRs) (Idaho National Laboratory, 2025).

[61] While some existing reactors, e.g. in India, fall within a smaller capacity range, they are not considered modern SMR concepts, as the principal distinguishing feature of modern SMRs is their modularity and design standardisation.

enable similar efficiency gains in nuclear construction, although this remains to be demonstrated at scale.

SMR concepts currently span a wide range of TRLs (Table 7). The most advanced designs are based on PWR/BWR technologies, building on operational experience and adaptations from established GW-scale models, scaled down in capacity and incorporating modular construction principles. HTGR SMR designs are an exception. Although GW-scale HTGRs have not been deployed commercially, their SMR variants are already in operation in China. In Europe, HTGRs are being developed by the SNETP , but their commercial deployment is not expected, however, in the near-to-mid-term. Other SMR designs, including LMRs and MSRs, remain at lower levels of technological maturity (Amin et al., 2024), although operating GW-scale SFR designs are available in China and Russia[62].

Although some conceptual (and operating) SMR designs are intended for civil marine applications, EU national energy strategies primarily focus on the adoption of land-based generation.

Table 7. SMR reactor families with their corresponding indicative TRL, number of identified designs, and examples

SMR Technology Type	TRL*	Number of designs	Examples
Water-cooled reactors (WCRs)	3-9	32	• *CAREM-25* (Argentina) • GE Vernova-Hitachi *BWRX-300* (US) • Rolls-Royce SMR (UK) • Steady Energy *LDR-50* (Finland) • NuScale *VOYGR* (US) • NUWARD SMR (France) • Westinghouse *AP300* (US) • *KLT-40S* (Russia)
Gas-cooled reactors (GCRs)	3-8	30	• *HTR-PM* (China) • Jimmy HTR (France) • *Xe-100* (US)
Liquid-metal cooled reactors (LMRs)	3-8	19	• *ARC-100* (Canada) • *EAGLES-300* (Belgium) • HEXANA (France) • Natrium Reactor (US) • Newcleo- *LFR-AS-200* (France)

[62] Russia's *BREST-OD-300* LFR reactor is under construction, with the vessel assembly 70% complete as of January 2026.

			• Stellaria (France) • *BREST-300* (Russia)
Molten salt reactors (MSRs)	2-4	25	• Energy Well (Czechia) • IMSR (US) • Thorizon One (Netherlands)

Source: NEA (2025) and Chmielewska-Smietanko et al. (2025), complemented by own research.

Note: * TRLs are indicative only. TRL estimations vary largely depending on specific achievements of designs. For instance, while some GCRs may achieve high TRL due to commercial deployment in China, they are generally considered less mature than WCRs. Likewise, not all LMR types achieve the same TRL, e.g. SFRs involve a significantly higher maturity level as a proven technology, compared to LFRs, which have not yet operated. WCRs encompass both PWRs and BWRs. GCRs encompass HTGRs. Out of a total of 127 SMR designs identified in the SMR dashboard, 20 designs are pursued by 19 organisations in Europe. Designs include land-based, marine-based, multi-module, and mobile concepts. Not all designs pursue commercial operation objectives.

Globally, only four SMRs have progressed towards operation: two KLT-40S PWRs deployed on a floating platform in the Arctic port town of Pevek, Russia (grid-connected in late 2019), and two land-based HTR-PM HTGRs in Shidao Bay, China (grid-connected in 2023) (IAEA, 2024b). Projections for upcoming SMR deployment vary significantly, depending on sources, and range from approximately 400 to over 1 000 units expected to come online by 2050 (IEA, 2025c; EY, 2024). In its high-growth scenario, the IAEA (2024b) anticipates SMRs to account for up to 24% of global nuclear capacity by 2050, although significant barriers must be addressed to achieve this. According to EY (2024), the global SMR capacity could reach 100 GW, with Europe accounting for 17%.

As of Q2 2026, the NEA identified 127 SMR projects worldwide, 16 of which are located in the EU, as shown in Table 8.

Table 8. Total SMR projects in the EU disaggregated by the number of projects that have submitted certification applications and the number of projects in pre-licensing stages

Member State	Total number of projects	Number of projects that have submitted certification applications	Number of projects in pre-licensing stages
France	10	2	7
Poland	2		2
Finland	1		1
Netherlands	2		1
Romania	1		1

Source: data from NEA (2025) complemented by own research.

To date, no commercial projects within the EU have entered the construction stage. The 8th PINC (2025) estimates that SMR capacity in the EU could reach between 17 and 53 GW by 2050. Belgium, Czechia, France, Poland, Romania, and Sweden have already selected sites and technologies for deployment (section 5.2.1).

5.2 SMR deployment in the EU

In recent years, SMRs have become a focus of EU industrial and energy policy. The European Industrial Alliance on SMRs was launched in 2024, building on earlier preparatory work and the pre-partnership initiative involving the Commission, ENSREG and SNEPT. In September 2025, the Alliance adopted a five-year Strategic Action Plan structured around 10 priority actions spanning technology development, supply chain resilience, and the fuel cycle, with the main objective of deploying the first SMRs in the early 2030s.

Section 5.2.1 discusses developments in SMR design selection and related considerations of technological sovereignty, while section 5.2.2 outlines the main barriers to SMR deployment in the EU.

5.2.1. EU design selection and technology sovereignty

A broad range of SMR technologies is under development in the EU and globally. LWR-based designs are closer to commercial deployment, with first units expected in the early-to-mid-2030s. Table 9 presents an updated status of the earliest SMR projects in the EU.

The GE-Hitachi BWRX-300 is already under construction in Darlington (Canada), with operation expected around 2030, and several units are planned in Poland, with timelines also pointing to 2030-2035. Other SMRs are under development as well as at different TRLs. AMRs remain at lower TRLs, with medium to longer terms of their prospective deployments. This implies a dual-track approach: accelerating industrial deployment of Gen III+ SMR technologies while doubling down on R&D&I for Gen IV AMRs.

Table 9. Status of EU Member States' early SMR projects in advanced stages for deployment

EU Member State	Project/Company	Status	Expected Deployment
Czechia	ČEZ + Rolls-Royce SMR	Early Works Agreement signed (July 2025) covering preparatory work (licensing and environmental assessments); Temelín site selected.	Second half of 2030s
Estonia	Fermi Energia + BWRX-300	BWRX-300 technology selected; pre-licensing work ongoing.	Early 2030s
Finland	Steady Energy (LDR-50)	Pre-commercial stage; positive preliminary regulator (STUK) assessment; pilot plant under construction.	Steady Energy: pilot plant targeted for early 2030s
France	NUWARD (EDF)	In the design phase and programme development; 3rd phase of the joint early review (JER) process with 8 safety authorities.	2030s
France/Italy	Newcleo (LFR-AS-200)	Initiated safeguards-by-design engagement with Euratom at the EU level and progressing licensing in France with the ASNR (Nuclear Security and Radioprotection Authority) through submission of parts of the LFR project nuclear safety programme, following the 2024 submission of the same dossier for the nuclear fuel manufacturing facility.	Non-nuclear demonstrator in 2026; FOAK 2033 (France) and up to 4 commercial units 2034 (Slovakia)
Poland	GE-Hitachi BWRX-300 + OSGE (Orlen Synthos Green Energy)	Advanced planning phase: 1st site selected in Włocławek.	2 SMR units totalling 0.6 GW by 2035

Romania	NuScale VOYGR + Nuclearelectrica / RoPower)	FEED Phase 2 contract signed (July 2024); Doicești site confirmed; IAEA SEED follow-up found the site-selection process compliant; FID made in February 2026.	2029
Sweden	Rolls-Royce + Vattenfall	Vattenfall selected Rolls-Royce as SMR technology provider for the first three units; site selected in Ringhals.	3 reactors, operation mid 2030s at the earliest
	Blykalla	Application submitted for the first commercial application of 6 lead-cooled 330 MW AMRs; Norrsundet selected as deployment site	Early 2030s
UK	Rolls-Royce SMR	Selected preferred technology providers and 1st site for Rolls-Royce SMR selected – Wylfa, Anglesey (North Wales); contract signed with GBE-N (Great British Energy – Nuclear) in April 2026	Rolls-Royce SMRs: mid 2030s, 3 initial reactors, extendible to 8.
	Centrica/X-Energy (Xe-100)	US-UK agreement to build 12 Xe-100 reactors at Hartlepool (Northeast England)	Xe-100: mid 2030s

Source: CATF (2025b) complemented by own research.

Note: also considers the UK's status. Demonstrator units have been excluded. Project statuses as of Q2 2026.

Design selection

SMR deployment faces a strategic trade-off between technological diversity and early convergence. With about 100 active developers globally, only a limited number of designs will reach commercialisation. This raises a strategic choice between either allowing technologies to evolve organically or identifying lead designs early. Evidence from international experience suggests early selection of lead designs can improve deployment outcomes (CATF, 2025b). While diversity supports early innovation, serial production requirements and the need for greater alignment among Member States licensing regimes increasingly point towards the need for coordination.

The SMR Industrial Alliance has therefore selected eight (originally, nine) priority projects based on reactor designs of both European and non-European origin. These SMR developers are already increasing cooperation: Calogena and Steady Energy are joining forces in the CityHeat project, and the European EAGLES Consortium and Newcleo have announced collaboration. Regulatory cooperation on designs is also emerging, including joint regulator work of several regulators on NUWARD to avoid licensing delays.

However, design selection will ultimately be defined by Member State preferences and evolving use cases (section 5.3). Capacity choice is also critical. For example, Romania has selected lower-capacity NuScale units (77 MW), while Czechia and Sweden have opted for larger Rolls-Royce SMRs (470 MW). This highlights the importance of aligning reactor design with market needs, while ensuring that the nuclear industry can respond effectively.

EU-based and non-EU designs

A central strategic question is whether EU industrial policy should prioritise EU-based designs or allow non-EU designs to have an equal footing. With US GE-Hitachi, NuScale and UK Rolls-Royce SMRs increasingly present in Member States' deployment plans, potential risks of dependence on non-EU designs need to be factored. At the same time, this must be balanced against the importance of international cooperation, as recognised, as recognised in the EU's SMR Strategy. More broadly, 'made in the EU' provisions issues related to nuclear components are currently part of the negotiations on the Industrial Accelerator Act (IAA). While openness to non-EU technologies needs to be preserved, certain safeguards may be required to ensure EU capability to manufacture, maintain, and service the key components and operate the full nuclear power plant (section 4.1.2).

5.2.2. Main bottlenecks

SMR deployment is currently constrained by three interlinked bottlenecks: (i) licensing, (ii) financing, and (iii) supply chains, with (iv) an additional constraint for AMRs (as well as most Gen IV reactors), related to fuel availability and fuel types.

Bottleneck #1 Licensing

Licensing is one of the most complex and consequential barriers for SMR deployment. In principle, SMRs are subject to the same licensing requirements as large-scale reactors, covering safety, siting, fuel, and waste management. While their smaller size and standardised designs could eventually simplify procedures, FOAK SMR projects are still expected to face lengthy, complex, and costly approval processes because of their technological novelty and need for an extended validation process. Similarly to large-scale reactors, this may discourage investment in SMRs (Amin et al., 2024; Sam et al., 2023). Only nth-of-a-kind (NOAK) SMR units are likely to benefit from more streamlined licensing processes, particularly if more harmonised regulatory criteria are adopted across Member States, and a high degree of project replication is achieved.

The challenge is further compounded by the expected multiplicity of deployment sites. These will largely depend on the use cases of SMRs, but can range from existing and former nuclear sites to non-nuclear sites (potentially urban or industrial settings). This raises significant questions not only for nuclear regulators but also for local permitting authorities, which often lack experience with projects of this level of complexity. This could create systemic bottlenecks similar to those observed in grid connection queues, and selection mechanisms may become necessary. Essentially, it may mean that the sequence in which requests are evaluated may have to be based on 'ranked priority' (i.e. by previously defined indicators reflective of project maturity), rather than on a first-come, first-served basis. Regulators may need to prioritise applications based on the credibility and readiness of respective projects, rather than process them sequentially. While no formal policy initiatives currently exist in this direction, this analogy highlights emerging system-level constraints.

Another key issue remains the lack of alignment between technology readiness and licensing readiness of SMR designs. This necessitates closer cooperation among regulators from the early stages of design development. Current regulatory approaches to licensing remain largely national, reflecting historical path dependency and institutional differences across Member States. A shift towards greater regulatory dialogue is essential to enable designs approved in one country to be approved in others, subject to limited site-specific adjustments. SMR Gen III+ designs provide an opportunity to test new forms of regulatory cooperation, as they are based on commercially proven technologies while introducing new deployment formats.

Encouragingly, efforts to address licensing challenges are already beginning to emerge through bilateral initiatives involving national regulators, as well as through international platforms such as the IEA and the NEA, and within the EU. Within the SMR Industrial Alliance, Working Group 6 focuses on safety, safeguards, and security. ENSREG is exploring regulatory cooperation, including the development of JERs for SMR designs as part of the ENSREG SMRs Task Force set up in early 2025. These reviews aim to provide a shared technical assessment that could facilitate more harmonised approaches across Member States. Potentially, this task force may evolve into a further regulatory coalition.

However, important limitations remain. JERs currently enable information sharing but lack legal status in national licensing procedures. They are necessary but not sufficient. Mechanisms such as the NZIA's regulatory sandboxes, also noted in the EU's SMR Strategy, may support pre-licensing phases, creating a controlled environment to test technologies, but their application in the nuclear sector is likely to remain constrained by the need to maintain the highest safety standards. More fundamentally, there is a need to develop legal frameworks that enable regulators to rely, where appropriate, on assessments conducted by their counterparts in other jurisdictions, thereby avoiding unnecessary duplication and streamlining SMR licensing processes while preserving the ability of national regulators to address country-specific regulatory requirements.

Bottleneck #2: Financing

As with GW-scale reactors, financing remains a structural gap for SMRs. More broadly, the challenge lies in de-risking FOAK projects and, in turn, increasing the attractiveness of SMRs for private capital.

The EUR 200 million support as EU budgetary guarantees under the current InvestEU announced in the EU's SMR Strategy as 'an additional temporary InvestEU top-up until 2028 to further support the deployment of the initial commercial units of innovative nuclear technologies', represents an important step forward. However, questions remain regarding this support's operationalisation, leverage potential, and overall scale of available funding. Ongoing negotiations on the next MFF also explore the bridges to be built with the EU Competitiveness Fund.

Bottleneck #3: Supply chains

A competitive SMR sector requires a sovereign and scalable European supply chain, the development of which represents another major challenge (section 4.1.2). The SMR economics bet on modularisation and factory-based production in controlled industrial environments. However, the feasibility of large-scale standardised manufacturing remains unproven, and without a significant extent of unit modularisation, SMR supply chains risk falling short of the deployment ambitions. Supply chains also require predictable demand and clear expectations regarding future SMR use cases. However, the scale of future demand and the extent of SMR deployment across different applications remain uncertain, thereby creating a circular constraint that may slow supply-chain development.

Regulatory fragmentation also affects supply chains, particularly the absence of harmonised definitions of nuclear-grade and non-nuclear-grade (i.e. commercial-grade or industrial-grade) components across Member States. This increases uncertainty for suppliers and limits scale effects that hinder the establishment of large-scale fabrication capacity.

With respect to nuclear components, the successful construction (on time and on budget) of the reactor's conventional island (housing the steam turbine, generator, condenser, and the I&C system) is critical to containing project costs and delivery timelines. Through their design standardisation and regulatory framework harmonisation, large-scale component manufacturing in a standardised, modular way could help avoid the impacts of cost overruns and project delays. NZIA recognises certain nuclear-related components (e.g. steam turbines) as strategic technologies, but scaling will require additional support.

These could include public guarantees to reduce private capital risks and dedicated funding mechanisms for industrial partnerships in EU value-chain planning.

The question of 'European content' is also central. There is a growing emphasis on ensuring that a substantial share of the SMR value chain is developed within Europe. However, defining what constitutes 'European' content remains politically and legally complex (Arnal, 2026). Proposals such as the IAA show component-based approaches, requiring a certain proportion of key components to be produced in Europe. Considerations of whether this ambition is sufficient vary across stakeholders. A balance is needed between establishing sovereign EU supply chains and international cooperation.

Cross-border industrial cooperation could play a role in this regard, helping to anchor supply chains across the EU. The next big step in SMR supply chain development would be the delivery of large industrial projects that integrate suppliers and components sourced across multiple Member States. This also includes Member States without nuclear programmes, such as Italy and Germany, which may nevertheless be active in parts of the nuclear supply chain.

Bottleneck #4. Fuel for Gen IV SMRs (AMRs)

For Gen III/III+ LWRs (both GW-scale and SMR formats), the standard fuel today is uranium oxide ceramic fuel in the form of low-enriched uranium (LEU)[63] fuels. While LEU fuel production enjoys mature and commercial supply chains, the EU faces a pressing geopolitical challenge in diversifying fuel supplies and expanding domestic enrichment capacity, as around 24% of its LEU fuel supplies are imported from Russia (ESA, 2025).

Many Gen IV reactors, both AMRs and GW-scale concepts, however, rely on a more diverse range of fuel forms, tailored to their technical specificities. Around 60% of SMR designs depend on fuels that are not yet available at a commercial scale (NEA, 2025). The NEA (2025) specifies that 39 SMR designs plan to use higher-enrichment HALEU[64] fuel forms, for example, in composite architectures such as TRISO particle fuel. Some SMR designs consider the inclusion of back-ended HALEU fuel reuse, for which lower fuel provisions would be required (Insepov et al., 2025).

The adoption of HALEU fuel can improve the overall plant capacity factor and reduce fuel costs by extending periods between refuelling. Largely, it increases the energy density per

[63] LEU fuel typically comes in the form of U-235 enriched to 3-5%.

[64] HALEU fuel typically comes in the form of U-235 enriched to 5-20% levels. Enrichment levels must be kept below 20% to comply with the International Atomic Energy Agency (IAEA) guidelines regarding the Non-Proliferation Treaty (NPT).

unit of fuel (Carlson et al., 2022). From a technical perspective, some SMR designs require fuel with higher levels of enrichment due to:

(i) *Smaller reactor size*: smaller reactor cores require a higher concentration of fissile material to sustain criticality over long periods.

(ii) *Longer refuelling cycles*: many SMR concepts are designed to operate for long periods without refuelling, i.e. every 3-7 years, compared with GW-scale reactors, which require refuelling every 1-2 years. Some SMRs are being designed to operate for over 30 years without refuelling (NEA, 2025). Therefore, more fissile material is needed at the start of the first cycle, i.e. a greater U-235 concentration.

(iii) *Higher neutron leakage*: smaller cores have a higher surface-to-volume ratio, increasing the likelihood of neutron leakage from the core. Greater enrichment levels ensure the presence of enough neutrons to sustain the fission reaction (NEA, 2024d).

However, many of these options remain immature, constituting a significant barrier to many Gen IV designs currently under development. Today, commercial production of HALEU fuel is limited to Russia, although China and the US are scaling up their production capacities towards near-commercial levels. The expansion of European HALEU fuel production is essential. The British/Dutch/German consortium Urenco and French Orano, which together account for 62% of the enriched uranium used in the EU, are actively developing their advanced fuel production capabilities in light of future HALEU needs (ESA, 2023). For example, GBP 196 million has been invested to develop Urenco's HALEU fuel fabrication facility at the Capenhurst site in the UK, with the aim of producing at least 27 tonnes of fuel annually.

These challenges underscore the need to consolidate fuel supply chains and develop new fuel cycle capacities, including new fuel production and, where necessary, additional fuel reprocessing capacity (Box 10).

Box 10. Fuel recycling and reprocessing

The production and use of MOX fuel – derived from plutonium and depleted/reprocessed uranium – reduces exposure to international supply chains and limits dependence on enriched uranium, including the one supplied by non-EU providers. While MOX fuel is already used in Gen III reactors, such as by the French nuclear fleet, fast reactors, such as SFRs and LFRs, are generally considered better suited to closed fuel cycles and more extensive recycling of spent nuclear fuel.

This technological choice has the potential to directly address some of the most pressing challenges facing the nuclear fuel cycle today: (i) closing the fuel cycle and (ii) reducing the EU's dependence on newly mined uranium.

Looking forward, these considerations are further reinforced by expected market dynamics: From 2030 onwards, China is projected to become the world's largest uranium consumer. Prices are forecast to rise significantly, potentially exceeding 300 USD/lb, well above the 2024 peak of 100 USD/lb and the 2020 level of around 30 USD/lb. In this context, the strategic autonomy resulting from advanced recycling and closed fuel cycle technologies becomes increasingly critical.

5.3. SMR APPLICATIONS: DEMAND SIDE

SMRs offer significant advantages because of their versatility in applications, modular deployment, and operational flexibility. These characteristics potentially enable their deployment across a variety of settings and support a broad spectrum of applications, including both electric and non-electric uses, as well as hybrid configurations. However, this broad range of potential applications also creates uncertainty. The diversity of proposed use cases, combined with the wide variety of SMR designs at different TRLs, means that it remains unclear where, and for which applications, SMRs can deliver the greatest added value. If this ambiguity persists, it may weaken their competitiveness relative to more clearly defined alternatives and ultimately slow market development.

While GW-scale reactors have historically been, and are expected to remain, primarily used for power generation, the main applications for SMRs in Europe are still evolving. Ultimately, market forces will determine where SMRs prove most valuable, prompting technology providers to adapt to the market demands, that is, specific capacity and core outlet temperatures. At present, Gen III SMRs are being selected primarily based on Member State needs, particularly for district heating and industrial purposes for electricity, although use cases remain partly unclear and continue to evolve. EY (2024) projects that by 2050, approximately 50% of SMRs will be deployed for industrial applications, 40% for grid applications, and 10% for district heating.

Demand from industrial clusters has arguably been central to the rationale for SMRs. If SMRs can meet these clusters' needs for electricity, including for hydrogen production, and both low- and high-temperature heat (the latter in the case of AMRs), they could offer a viable solution for industrial decarbonisation. Rather than relocating energy-intensive industries towards future low-carbon energy supply centres, SMRs could enable existing industrial locations to be preserved through on-site deployment (NEA, 2025), leveraging flexible approaches for distributed deployment. Several Member States, including Poland, have expressed interest in SMRs, particularly for industrial clusters, although concrete deployment plans are still evolving.

Should SMRs be considered for industrial applications, whether to provide electric, thermal energy, or both, siting them in proximity to the industrial demand is deemed highly advantageous, particularly to avoid the costs involved with the buildup of extensive transport infrastructure (transmission lines and steam/hot water pipelines), and to avoid electrical and thermal losses during transmission, making an efficient use of the reactor outputs.

Power applications

For grid-connected electricity generation, SMRs with lower reactor capacities may improve their suitability in Member States where new GW-scale reactors may be considered oversized with respect to their electricity needs, such as Estonia, which is actively exploring an SMR option.

The first SMR units deployed in the EU are, however, likely to largely cater for off-grid operation, supported by offtaker agreements with industries requiring a continuous power generation load to fulfil their operational power needs. In addition to energy-intensive industries, electricity demand may particularly come from technology companies, in light of rising global power demand by data centres[65] for AI training and usage. Other potential applications include micro-grids, remote and islanded power systems, military installations, and maritime propulsion.

Non-power applications

SMRs are more widely endorsed than GW-scale reactors for a broad range of non-electric applications, mainly because of their distributed deployment. However, their ability to

[65] Globally, data centres account for 1.5% of electricity demand and are expected to more than double by 2030 (IEA, 2025d). Cases such as Ireland's, for which data centres already consume 22% of national electrical demand (CSO, 2025), become especially critical to ensure the security of low-carbon electrical supply.

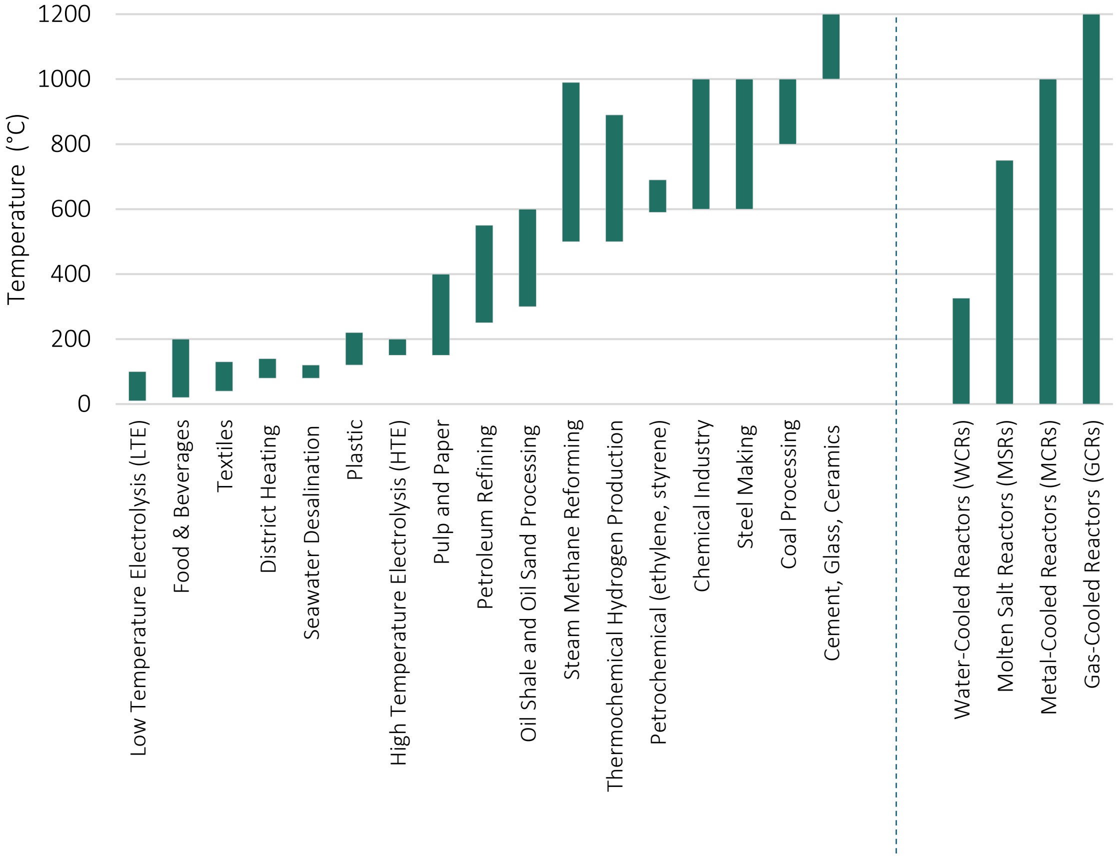
serve these is constrained by the core outlet temperatures they can achieve. Like GW-scale reactors' cogeneration capabilities (section 2.2.1), Figure 13 compares the expected core outlet temperature ranges of the main SMR reactor types with the temperature requirements of specific non-electric end-use applications.

The initial set of SMRs to be deployed in the EU is expected to reach core outlet temperatures[66] of up to 325°C. This would make SMRs eligible to participate in thermal output[67] to various low-to-medium grade industrial users (e.g. the paper and pulp, food and beverages, or the plastics industries) and non-industrial applications (e.g. district heating, seawater desalination, and hydrogen production). As more advanced (Gen IV) designs reach commercial stages, the suitability of SMRs for non-electric applications is to be expanded, broadening the range of industrial processes for which SMRs can provide decarbonisation pathways.

[66] Core outlet temperatures are representative of maximum temperatures and are not fully representative of the temperature received by the end consumer (inferior). These depend on the temperature of the extracted heat leaving heat exchangers.

[67] The maximum thermal output of SMRs is approximately 1 GWt: it translates directly from its maximum electrical output of 300 MW.

Figure 13. Temperature requirements of end-use applications and SMR reactor family core outlet temperatures



Source: data from Locatelli and Mancini (2010), Castagnola et al. (2014), NEA (2025), EY (2024). Dataset available in the Supplementary Information.

Note: reactor core outlet temperatures are representative of maximum temperatures and are not fully representative of the temperature received by the end consumer (i.e. inferior). These depend on the temperature of the extracted heat leaving the heat exchangers.

Industrial heat

The early wave of (water-cooled) SMRs in Europe is only expected to provide low-to-medium-grade heat. Early designs will reach core outlet temperatures of up to 325°C (achieved by the Rolls-Royce SMR), meaning that they would provide heat solutions only for a limited number of industrial applications. While these SMRs can provide round-the-clock baseload heat provision at constant rates to industrial consumers, the relative ease with which lower-temperature industrial processes can be readily electrified at a lower cost by alternative sources, such as heat pumps, electric boilers, or electromagnetic heating (Baldea et al., 2025), inevitably raises concerns about the suitability of making investments in SMRs for lower output temperatures, particularly for the initial WCR SMR designs.

The industries that need thermal energy at higher temperatures are only expected to benefit from SMRs in further waves, in which more advanced (non-WCR) designs, such as MSRs, LMRs and GCRs, start being deployed, able to achieve core outlet temperatures of up to 750-800°C. Core outlet temperatures of up to ~1,200°C[68] are only achievable by HGTR designs[69], which are in early deployment stages in the EU. More advanced SFRs and LFRs could achieve temperatures of ~500°C – broadening a more immediate spectrum of industrial processes where SMRs could play a role. Perhaps only these higher outlet-temperature reactors present a greater extent of competitiveness as a credible option for industrial decarbonisation.

District heating

Being capable of providing thermal outputs within the temperature range required for district heating, the first wave of SMRs could become a readily available option for this purpose. However, using reactors with higher outlet temperatures than needed for district heating may induce sub-optimal operation, which could result in uneconomical reactor operation. For this reason, SMR designs tailored to the needs of district heating purposes are being developed, where thermal energy is their primary output.

A few designs are being developed in China[70]. In Europe, the NUWARD SMR design aims for cogeneration with district heating as one of its core thermal output uses. Steady Energy's LDR-50 SMR design is targeted for district heating uses only, aiming to bolster efficiency to 95% (Sokka et al., 2024). This concept has already been considered for deployment in three municipalities, including Helsinki. Its developer has signed 15 agreements for unit developments and is targeting other district heating markets, such as Poland and Sweden. However, the economics of these SMR applications are yet to be demonstrated at FOAK and further NOAK stages.

As the proximity to consumption centres is a core requirement for reactors used in district heating applications, i.e. 5-15 km (NEA, 2022c), the more distributed nature of SMRs offers a greater applicability for this purpose compared to GW-scale reactors. Their modular characteristics and expected distributed deployment could allow better access to heating markets at a greater spatial coverage, delivering heat to a larger population

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[68] This is the highest achievable temperature by an HTGR SMR design – the A-HTR-100 – the relatively immature South African project. More advanced HTGR projects achieve maximum temperatures of 750-850°C.

[69] China has already deployed an HTGR SMR in Shidao Bay, and the US is expecting to deploy its first HTGR SMR unit – the Xe-100 – in 2027, able to produce steam at 565°C.

[70] China has three SMR low-temperature reactors designed specifically for district heating: NHR-200 (200 MWt), Landstar-1 (200 MWt), and the DHR-400 Yanlong (400 MWt) (World Nuclear Association, 2024).

size. Yet, similar to GW-scale district heating applications, the deployment of SMRs for heating remains limited by regional use.

Hydrogen

With core outlet temperatures of up to 325°C, the initial SMR units to be deployed in the EU meet the temperature requirements to participate in hydrogen production – either through LTE or HTE (section 2.2.2). While GW-scale reactors exhibit improved performance through economies of scale (IAEA, n.d.b), SMRs may offer advantages through decentralised deployment and therefore proximity to industrial offtakers, a condition that existing GW-scale reactors do not necessarily have. The versatility in the siting possibilities of SMRs, including their co-location with electrolysers, enables them to be placed close to industrial demand centres where hydrogen demand from specific sectors may become high. This approach could also benefit hydrogen producers through a behind-the-meter configuration, avoiding network charges and reducing overall electricity and hydrogen infrastructure costs. The flexibility and scalability of SMRs may enable nuclear-based hydrogen production in applications and markets that are inaccessible to larger reactors or other low-carbon sources.

One disadvantage of hydrogen production using SMRs, compared with other sources and GW-scale plants, is the higher costs associated with SMRs (section 5.4). As current electrolysers run on electricity, higher costs of electricity produced by SMRs inevitably result in higher costs of hydrogen production. This is exemplified in their higher LCOH relative to that produced from GW-scale reactors (Pompodakis and Papadimitriou, 2025). Himona and Poullikkas (2026) estimate the LCOH to range from 2.80 to 9.80 EUR/kgH_2, considering different reactor and electrolyser configurations. While the lower end of this range appears comparable to other hydrogen production pathways (section 2.2.2), it relies on the assumptions of substantial cost reductions in both electrolysers and SMR units. Achieving these reductions is therefore essential for SMR-based hydrogen to be competitive against alternative sources. Moreover, for hydrogen from SMRs to compete with that from steam-methane reforming, a cost below 3.33 EUR/kgH_2 should be achieved (European Hydrogen Observatory, 2025).

Desalination

A frequently overlooked non-electric application of SMRs is their potential integration with desalination plants to produce potable water in water-stressed regions. Through electrical, thermal, or hybrid coupling, SMRs can simultaneously generate electricity and freshwater, meeting the energy requirements of both power-driven and thermal desalination technologies.

Compared to GW-scale, SMRs are generally considered better suited to desalination applications due to their greater siting flexibility, modularity, and lower generating capacities (Sudalaimuthu et al., 2025). While no European SMR projects currently envisage coupling with desalination plants, several countries in the Middle East, including Saudi Arabia and Jordan, are exploring SMR deployment specifically for desalination purposes. Notably, designs such as South Korea's SMART reactor are intended for drinkable water production.

5.4. ECONOMICS OF SMRS

SMR modularisation allows for economies of multiples to kick in. Unlike economies of scale, these benefit from repetition, standardisation and shared design elements to allow cost reductions through streamlined production and replication across units. This modular approach can reduce construction lead times[71] and lower the risk of cost overruns, improving overall investment risk profiles. Lower unit sizes and upfront capital requirements may also broaden financing options and attract a wider range of investors beyond government-owned entities. Co-siting fixed costs also allows them to be shared across multiple SMR units at a single site, rather than deploying single, stand-alone reactors. This can reduce costs by approximately 10-25% (Mignacca and Locatelli, 2020), driven by shared licensing and site-permitting costs, personnel, and the use of existing grid connections.

However, SMRs' smaller capacity also results in higher costs per unit of generated electricity. The expectation is that it will be partly offset by greater siting flexibility, faster learning curves, simpler construction processes, and co-siting advantages. This is yet to be demonstrated.

Construction costs

Despite no projects having yet advanced towards operational stages in Europe, early SMR projects already imply considerable investments. For instance, Romania's 462 MW Doicești project is estimated at around EUR 4.1 billion (8 900 EUR/kW). Poland's first 300 MW SMR unit is projected at EUR 1.1 billion (3 700 EUR/kW)[72]. Yet FOAK cost uncertainty remains high, and not enough quantified information is available on upfront costs for specific projects.

[71] SMRs are expected to be delivered in 3-4 years, as opposed to the typical >10 years experienced by GW-scale reactors (EY, 2024).

[72] Estimates involve high uncertainty and are only indicative. Per-capacity cost calculations only consider upfront capital costs and installed capacity.

Overnight costs of first demonstrator SMRs are expected to range between 13 300-17 700 EUR/kW, transitioning to 7 000-11 500 EUR/kW for FOAKs and reaching 4 400-6 200 EUR/kW for NOAKs (EY, 2024). NuScale expects a reduction from FOAK's 7 000-11 000 EUR/kW to NOAK's 3 500 EUR/kW (Rothwell, 2022). According to Van Hee et al. (2024), upfront CAPEX costs for first SMRs would be, on average, 41% higher than GW-scale plants, considering only planned project costs and excluding cost escalation and overruns. Although SMR per-capacity costs remain high, the total upfront cost is lower because of smaller unit size, and revenues can begin earlier thanks to expected shorter construction times. This could reduce payback periods by up to half compared with GW-scale reactors (20-30 years), improving SMR cash-flow profiles (IEA, 2025c).

The promise that SMRs can avoid the cost overruns and construction delays seen in GW-scale projects has yet to be demonstrated. Commissioned SMR projects have already experienced significant budget overruns and construction delays (Schlissel and Wamsted, 2024). China's Shibao Bay 1 reactor's final cost escalated to three times the initial estimate and took eight more years to build than projected. Russia's two floating SMRs exceeded the budget by a factor of four and exceeded construction times by 10 years. Argentina's CAREM-25 reactor, which is still under construction (delayed by 11 years), has already surpassed the initial budget by a factor of seven and was recently halted.

While the challenges inherent to FOAK designs partially explain such delays and budgetary overruns, sustained investor confidence will depend on avoiding similar patterns beyond FOAKs. Demonstrating predictable delivery and cost control will be essential for attracting corporate investment and establishing SMRs as a credible investment case.

LCOE estimations

SMR LCOE remains highly uncertain because of the lack of projects having advanced towards the commercial stage and country-specific factors. It remains unclear whether SMRs can compete in the short-to-medium term with GW-scale reactors in terms of LCOE, which is expected to be, on average, 20% higher than for GW-scale reactors, and estimated to reach 115 EUR/MWh in the EU (IEA, 2025c).

The overall economic competitiveness of SMRs is yet to be proved. Learning effects from modularity, standardisation, series fabrication, and economies of multiples could reduce LCOE at a relatively fast learning rate, initially up to 10%, before plateauing (Wieser et al., 2025). Regardless of application, SMRs will need to prioritise high load factors to ensure economic viability.

Lewis et al. (2016) suggest that producing over 10 SMRs per year could lead to learning rates of 8%, enabling LCOE parity with GW-scale nuclear plants once a cumulative SMR capacity of 5 GW has been deployed. Long-term projections suggest potential LCOE convergence or even outperformance of GW-scale reactors by 2043 (DNV, 2025).

Financing SMRs

In contrast to ongoing challenges in financing GW-scale nuclear (section 4.2), SMRs are often presented as a more accessible investment profile for private capital because of their lower upfront costs, shorter construction periods, and therefore earlier revenue generation. According to the IEA (2025c), SMRs are expected to involve upfront investments of <USD 1.8 billion.

Standardised designs and multi-unit deployment at a site further reduce risk by enabling phased development, and the early entry into operation of the first units can accelerate the payback period. This would enable investors to start recovering invested capital more efficiently, which could then be re-invested at the same site to support capacity expansions, creating a scalable growth model and an easier-to-finance phased deployment strategy (IAEA, 2024). In principle, these features can make SMRs more attractive to private investors because budgets become more manageable.

Nevertheless, public support will likely remain necessary, especially for the demonstrators and FOAKs. Globally, SMR investment totals EUR 13.6 billion, from which EUR 8.9 billion originates from public entities and EUR 4.8 billion comes from private investment. Technology companies like Google, Amazon, Meta, and industries like Dow Chemical have recently invested in different SMR designs (NEA, 2025).

The lower project risks associated with NOAK SMRs may suggest that multi-party risk-sharing requirements may not be as extensively needed as for more capital-intensive GW-scale projects. Yet SMRs still face many of the same financing, construction, and uncertainty challenges. It will therefore be essential to bring together industry stakeholders and financial institutions to explore collaborative approaches for co-funding SMR projects, whether through order books or other financing mechanisms. In terms of financing instruments, tailoring existing frameworks to the specific characteristics and needs of SMRs appears to be the most viable option, while it may be advisable to exercise caution against the creation of new schemes that could duplicate existing ones and undermine investor confidence (UK Parliament, 2022).

Conclusions: the future of nuclear

Energy systems and technology choices are not purely technical constructs. They are socio-technical systems shaped by political choices, institutional frameworks and competing policy priorities over time (Geels, 2002; Geels et al., 2016). Consequently, they reflect cumulative compromises over regulatory decisions, market design choices and the roles of markets, the state and specific technologies (Thonig et al., 2021; Hughes, 2013). Debates over cost, reliability, system stability and energy sovereignty also reflect different visions of how energy systems should be organised and which trade-offs are deemed acceptable.

Nuclear energy's future role in Europe will depend not only on technological feasibility but also on how far political ambition is translated into credible framework conditions for deployment. Three aspects will be particularly decisive.

First, at EU level, the key question is whether nuclear is recognised as a long-term component of the EU's decarbonisation pathway and whether this recognition is reflected consistently across climate, energy, industrial and financial frameworks. This includes how nuclear is treated within sustainable finance, access to EU funding and de-risking instruments, inclusion in industrial policy, electrification strategies and related targets, and the treatment of nuclear-derived products such as hydrogen and synthetic fuels.

Second, deployment will depend on governments' willingness and capacity to pursue nuclear programmes consistently over multiple political cycles. This requires long-term political commitment, regulatory predictability, financing frameworks capable of supporting capital-intensive investments – especially governments' financial capacity to co-fund nuclear – and greater industrial cooperation among countries pursuing nuclear energy.

Third, success will depend on the ability of developers, vendors, and supply-chain actors to deliver projects on time and within budget, while also rebuilding industrial capabilities in Europe. This, in turn, should make nuclear more attractive to private capital and demonstrate the bankability of both established Gen III+ and emerging SMRs and Gen IV technologies.

Against this background, this section summarises the report's assessment of the main conditions required for successful nuclear deployment in Europe, and provides some suggestions for moving forward.

Assessment summary

This section summarises the core findings and assessments based on the criteria identified in the report's introduction and presented in Table *10*.

Durable and widespread political acceptance

Political support is particularly crucial for highly capital-intensive technologies with long lead times like nuclear energy. The level of sustained political acceptance of nuclear energy has varied significantly across Member States, including among those currently pursuing nuclear, largely reflecting domestic political dynamics (sections 1.1-1.2). This has resulted in 'start-and-stop' domestic policy cycles, which have had detrimental effects on the industry's learning curve and delivery capacity (section 4.1).

Diverging levels of support and differing national preferences regarding nuclear energy are likely to persist and will continue to shape its positioning at EU level (section 1). Until recently, nuclear was largely treated as a legacy technology by EU policy, included in modelling scenarios but lacking proactive support in terms of access to funding, dedicated inclusion into regulatory frameworks or integration into EU governance targets. However, in the current political cycle, nuclear appears to be gaining wider recognition (section 1.2). There is also a growing understanding of the need to approach energy system transformation more holistically, which may create a more favourable environment for reconsidering the role of nuclear alongside other low-carbon technologies.

Regulatory predictability

Regulatory predictability for nuclear remains mixed at best, reflecting a gap between increasing political recognition and fragmented policy implementation at EU level. While strategically there is a stronger emphasis on greater technological neutrality and a broader acknowledgement of all low-carbon solutions, nuclear is still not consistently or explicitly embedded across key EU frameworks, funding instruments and governance (sections 1.2-1.3 and across relevant sections). The lack of clear, long-term signals, coherent classifications and stable treatment across energy and industrial policies continues to affect investor confidence.

At the same time, significant variations at Member State level, including changing positions on nuclear over political cycles (sometimes radically, from phase-out to expansion plans), further undermines regulatory predictability.

Revenue adequacy

The electricity system's transformation will increasingly leave gaps in revenue adequacy that continue to weigh on the future of nuclear's business case (section 3.2). Revenue adequacy for nuclear remains a central challenge, as nuclear faces increasing long-term uncertainty in terms of revenues on wholesale markets, both because of increasing exposure to lower dispatch and price volatility. While the recent electricity market reform confirmed instruments such as CfDs to stabilise revenues, they typically do not cover the entire lifespan. Solutions to better address volume risks will also be needed, also by exploring greater exposure to industrial offtaker agreements.

Additional revenue streams in electricity markets, including balancing and ancillary markets and CRMs, are either modestly remunerated and constitute only marginal revenue sources, or are not suitable for nuclear because of its operational design. There is a need to better reflect on the full value of nuclear in the wider system.

Additionally, adjacent revenue streams, such as low-carbon products (e.g. hydrogen) or lead markets, may open new avenues but need further incentives. Frameworks for non-electric applications, including nuclear-derived heat, are insufficiently developed. Thermal vectors might require *ad hoc* incentive schemes to ensure derisking and enhance the decarbonisation of hard-to-abate sectors where electrification is hardly feasible.

Access to EU funding and de-risking instruments

Access to EU-level funding for nuclear remains limited and fragmented (section 4). Nuclear is largely excluded from major EU instruments. Even when nuclear is not formally excluded, it often has constrained access compared to other clean technologies. Existing support is largely channelled through limited Euratom research-oriented programmes. Instruments for large-scale industrial deployment are largely absent. One notable positive signal is SMRs being included in InvestEU.

Nuclear projects still face structural barriers in accessing mainstream EU energy funding. The availability of de-risking instruments for nuclear projects remains largely dependent on Member States rather than EU-level mechanisms. At EU level, financial institutions such as the EIB have historically played a limited role in supporting new nuclear projects, particularly in terms of comprehensive risk-sharing. Consequently, key instruments (CfDs, state-backed guarantees, and other risk-sharing models) have primarily been developed and implemented at Member State level. Emerging financing frameworks in several Member States signal progress. However, a coherent EU-level approach to de-risking nuclear investments is still lacking, leaving project developers reliant on national policy frameworks. Tailored risk-sharing mechanisms and clear EU backing for instruments such as PPAs and CfDs are, first and foremost, crucial for lowering the cost of capital.

Technology robustness

Technology risks vary significantly depending on reactor type and maturity. GW-scale EPR reactors have faced FOAK challenges, although there are expectations that France's planned subsequent iterations of a new reactor fleet may benefit from learning effects. There are alternative established designs, offered by non-EU vendors, although their ability to deliver these technologies in the European regulatory and labour environment is yet to be proved. They would also raise questions about dependence on non-EU technology providers. For SMRs, most projects remain at the FOAK stage, with uncertainties related to cost, performance, and scalability. AMRs are at an even earlier stage, largely within the R&D and demonstration stages.

While technology risks remain, the major gap does not necessarily lie in the technology itself, but rather in ambition, delivery capacity and enabling framework conditions. The point is that the US and China treat nuclear as a national energy priority and a key strategic focus. The latter managed to reach the fleet effect, whereas the EU has not yet committed to the same level of strategic prioritisation.

Robust supply chains

Years of suppressed construction activity have weakened industrial supply chains, resulting in gaps across manufacturing capabilities and steady supply. This fragmentation is particularly critical for GW-scale deployment and could become a bottleneck for SMRs, which rely on standardisation and serial production. Strengthening supply chains will require coordinated industrial policy, long-term project pipelines and investment in manufacturing capacity.

Construction performance and adequate delivery system (workforce, EPC capacity)

Construction cost overruns remain one of the largest challenges for the European nuclear industry. They affect the bankability of nuclear projects and thus their political and public attractiveness. Experience over the past two decades shows a pattern of delays and budget escalations.

While different EPC models and different vendors, also non-EU, are currently being considered by Member States, their ability to deliver on time and within budget remains uncertain. Constraints vary, as discussed in section 4.1, from design challenges to immature or incomplete designs to supply chain bottlenecks, particularly at Tier 3-4. Regulation, for example, licensing and permitting, can further contribute to delays if not sufficiently streamlined and predictable. Addressing these risks will require both industrial scaling by the nuclear industry and more enabling regulatory environments at Member State level.

The availability of a skilled workforce and experienced EPC capacity is a critical constraint in Europe. Workforce shortages, particularly in specialised engineering, construction and regulatory expertise, amplify these challenges. Rebuilding a robust delivery ecosystem will require sustained investment in skills development, stronger project pipelines to retain expertise and sustained political attractiveness of the nuclear industry at EU and Member State level.

Table 10. Assessment summary (results)

Durable and widespread political acceptance	Varies across Member States, often resulting in 'start-and-stop' domestic policy cycles; divergent national preferences will continue to shape nuclear's positioning at EU level. Until recently, at EU level, nuclear was treated as a legacy technology with a lack of support in terms of access to EU funding, regulatory frameworks etc. Currently, appears to be gaining stronger recognition; potential for a more favourable environment.
Regulatory predictability	Remains mixed at best; reflects a gap between increasing political recognition and fragmented policy implementation at EU level. Still gaps across key EU frameworks, funding instruments, and governance.
Revenue adequacy	Due to increasing exposure to lower dispatch and price volatility, there is increasing long-term uncertainty in terms of wholesale market revenues. While CfDs stabilise revenues, they typically cover a limited period; solutions to better address volume risks will also be needed, including industrial offtaker agreements. Additional revenue streams (i.e. balancing, ancillary, CRMs) are either modest or not suitable for nuclear's operational design. Adjacent revenues as low-carbon products (e.g. hydrogen) and non-electric applications are insufficiently developed and require incentive schemes.
Access to de-risking instruments and finances, EU funding	Remains limited and fragmented; EU instruments aimed at large-scale industrial development are largely absent. The inclusion of SMRs in InvestEU is a positive signal. Derisking instruments will remain largely dependent on Member States; emerging financing frameworks signal progress. Coherent EU-level approach still lacking.

Construction performance and adequate delivery system	The past two decades has shown a pattern of delays and cost escalations in construction affecting political and investor attractiveness. Different EPC/vendors are being considered but their ability to deliver remains uncertain. Design challenges, supply chain bottlenecks, licensing and permitting contributed to these delays. The lack of a skilled workforce remains a critical challenge.
Robust supply chains	Years of suppressed construction activity have weakened industrial supply chains, resulting in gaps across manufacturing capabilities and component supply. Risk becoming a bottleneck for SMRs, which rely on standardisation and serial production.
Technology robustness	Varies significantly depending on reactor type and maturity. Expectations of benefits from learning effects. SMRs remain at FOAK stage; AMRs at earlier TRLs.

THE WAY FORWARD: POLICY RECOMMENDATIONS

Nuclear energy's future role in the EU will ultimately depend on whether the conditions required for its deployment can be put in place at the EU, Member State and industry level. While many of the underlying challenges identified in this CEPS In-Depth Analysis report are well known, they remain only partially addressed. Building on the analysis and assessment presented above, the following recommendations could help create a more favourable framework for those Member States that choose to pursue nuclear energy.

1. A clearer long-term policy framework

As there is now political willingness at EU level to support nuclear deployment, greater long-term political and regulatory predictability is essential.

Political and regulatory predictability at EU level remains of paramount importance for nuclear energy, given its long investment horizons and the legacy of decades of divisive politics. The complexity of nuclear's place should be acknowledged: while Member States retain the sovereign right to pursue nuclear energy, as confirmed by several ECJ rulings, agreeing a common EU approach is difficult, and dedicated EU-wide nuclear targets are likely to remain politically unfeasible.

Nevertheless, recent political openness at EU level to support nuclear deployment is a positive step forward, which suggests that there is an opportunity to better accommodate Member States pursuing nuclear energy through recognising the contribution of all low-carbon technologies. Discussions on the post-2030 climate and energy framework provide the scope for a more flexible and tacit approach to planning, reporting and governance encompassing all low-carbon technologies, thus providing stronger long-term political signals and investment certainty.

2. Better treatment of nuclear energy across EU policy and regulatory frameworks

Nuclear energy and nuclear-derived products should be treated more consistently across relevant EU policy and legislative frameworks.

EU policymakers should proactively discuss and resolve the issues that most directly affect nuclear energy. This requires a systematic review of relevant legislation and policy instruments to ensure greater regulatory neutrality. A sustained and constructive dialogue is necessary even where progress on certain issues may remain politically challenging.

Regulatory neutrality should be ensured between different low-carbon production pathways. In particular, the development of hydrogen and e-fuel markets requires technology-neutral treatment of hydrogen production routes. Similarly, nuclear-derived products and heat should be appropriately recognised in emerging lead-market and industrial decarbonisation initiatives. EU lead-market and demand-creation instruments (e.g. the Industrial Decarbonisation Bank, European Hydrogen Bank, public procurement frameworks) should be operated on a technology-neutral basis, ensuring that nuclear-derived products are not structurally or practically excluded from accessing demand-side support.

3. More clarity over nuclear energy's future system role

Nuclear energy's future role in a low-carbon electricity system requires a more explicit policy discussion and greater clarity.

While nuclear can provide some operational flexibility, its primary system value lies in low-carbon, dispatchable capacity at high capacity factors. Further dialogue is needed on whether and how this contribution fits within electricity systems increasingly characterised by price-following operation.

Nuclear's contribution should be better reflected in discussions on system adequacy, security of supply and grid stability. Member States pursuing nuclear should ensure that nuclear deployment is considered as part of an integrated approach to energy system planning.

4. Revenue adequacy for nuclear in evolving electricity markets

Nuclear energy's long-term revenue model must be further considered as electricity systems evolve.

Nuclear power is increasingly exposed to changing market conditions characterised by greater price volatility, more frequent periods of low or negative prices and decreasing opportunities for traditional baseload operation. While the current EMD is likely to remain the foundation of the European market, further discussion is needed on how nuclear can maintain a viable business case under these evolving conditions. Long-term contracts, including CfDs and industrial offtake agreements, are likely to remain central to future nuclear business models.

Further consideration is also needed regarding whether and how nuclear's contribution to adequacy, system stability and low-carbon dispatchable capacity could be reflected better in remuneration mechanisms.

5. A strengthened investment framework for nuclear energy

Improving investability requires effective risk-sharing mechanisms provided by Member States, ideally complemented by EU de-risking tools and improved access to EU funding.

A coherent mix of grants, guarantees and de-risking tools is essential for reducing investment risk and for unlocking private capital. Member States willing to pursue nuclear should develop financing frameworks that holistically address construction, price and volume risks. While remaining politically challenging, targeted EU-level de-risking mechanisms could mobilise private capital and complement national frameworks, both for mature large-scale projects as well as FOAK technologies and demonstration projects.

The EU Taxonomy plays a key role in shaping long-term investment decisions on nuclear newbuilds. However, how it currently treats nuclear energy creates ambiguity for new investment. Policymakers should acknowledge these constraints and seek pragmatic solutions.

Greater recognition of nuclear across EU funding is needed. The next MFF should ideally provide clearer pathways for more nuclear participation, thus reducing current ambiguity and providing more synergies across various funding mechanisms, possibly including the European Competitiveness Fund and all relevant EU funding mechanisms. For innovation funding, a greater share of the Euratom budget should be allocated to all fission technologies, and there should be stronger synergies between Euratom and FP10.

6. Rebuilt industrial and delivery capacity

A sustained nuclear revival requires rebuilding Europe's industrial ecosystem and project delivery capabilities.

Member States pursuing nuclear should avoid stop-and-go policy cycles and provide a durable framework for deployment. Regulatory instability and shifting political commitments undermine investment certainty, weaken industrial capabilities and discourage supply-chain development. Establishing stable, long-term project pipelines is a prerequisite for rebuilding industrial capacity, including through orderbooks across Member States and 'coalitions of the willing' to advance regulatory harmonisation and supply chain cooperation. Some empirical examples, where nuclear deployment has followed a continuous trajectory, can serve as a useful reference.

Stronger coordination between governments and industry is needed to expand supply chains and manufacturing capacity and to develop workforce skills. Greater use of industrial policy instruments, including IPCEIs where appropriate, and cooperation among countries could support strategic supply-chain development. At the same time, the industry's core task is to improve project delivery performance to reduce construction risk and restore investor confidence.

7. Enabling conditions for SMR deployment

Realising the potential of SMRs requires coordinated action across Member States on developing integrated supply-chain ecosystems, among regulators on licensing, and better-channelled financing – including at the EU level.

Sustained progress across technological, industrial and policy dimensions will be required to move FOAK projects towards large-scale commercial deployment by the early 2030s. Key priorities include improving access to financing, reducing licensing issues and developing integrated supply-chain ecosystems.

The EU SMR Strategy provides an important starting point but now it needs to be operationalised. A time-bound implementation plan with clear milestones, dedicated resources and accountability mechanisms and the regulatory integration of SMRs and AMRs into EU legislative and policy frameworks would help translate strategic ambitions into investment conditions. More cooperation among national regulators is also needed to address licensing fragmentation, which could become a major obstacle to serial deployment. Industrial policy instruments, including SMR-specific initiatives and IPCEIs, should be leveraged more effectively to support manufacturing capacity and supply-chain development. For AMRs, continuing support on R&D&I and securing fuel-cycle capabilities (HALEU and MOX) are essential.

No single Member State can create an SMR market alone. Cooperation among interested Member States, including through coordinated deployment pipelines, shared order books and other 'coalition –of –the –willing' approaches, will be essential to achieve the scale necessary for successful commercialisation.

Annexes

Annex 1: Nuclear energy in the EU

By 2025, nuclear had reached an all-time high operational capacity of 420 GW, with 409 reactors operating globally (IEA, 2025c; WNISR, 2026b). This constituted roughly 10% of global electricity generation, making nuclear the second-largest low-carbon power source after hydropower.

In the EU, there are currently 98 nuclear reactors operating in 12 Member States, with a collective capacity of 98 GW (European Commission, 2025a; IAEA, 2026f). Table 11 lists these per Member State. Germany completed its nuclear phase-out in 2023.

Table 11. Share of nuclear energy in power generation, number of reactors, and installed capacity (GW) across each Member State with operable nuclear reactors

Member State	Share of nuclear in generation in 2024 (%)	Number of operable reactors	Capacity (GW)
Belgium	42.2	2	2.0
Bulgaria	41.6	2	2.2
Czechia	40.2	6	4.0
Finland	39.1	5	4.4
France	67.3	57	63.0
Hungary	47.1	4	1.9
Netherlands	2.8	1	0.5
Romania	19.8	2	1.3
Slovakia	60.6	5	2.3
Slovenia	35.0	1	0.7
Spain	29.9	7	7.1
Sweden	29.1	6	7.0

Source: IAEA (2026f).
Note: the share of generation is representative of 2024. The number of operable reactors and capacity is representative of 2026.

Annex 2: Overview of nuclear reactor technology

Nuclear power plants are thermal power plants consisting of one or several nuclear reactors in which energy (thermal and electrical) is released during nuclear fission reactions.

GW-scale reactors (with individual capacities up to ~1 GW) have long been the conventional format by which nuclear reactors have been deployed – providing large-scale electricity production to power systems. However, SMRs are emerging as smaller-scale nuclear fission reactors (typically <300 MW), which would enable their partially modular and serialised (factory-fabricated) construction, opening up new development pathways for the nuclear industry. Global SMR deployment is currently limited: there are no reactors in operation in the EU, and only a few worldwide. The first SMR units are expected to be deployed in the EU in the early to mid-2030s. Similarly, AMRs offer the prospect of enabling modular deployment of next-generation reactors. While the latter are primarily associated with the Gen IV concepts (see below), many categories may overlap, and definitions are not yet strictly defined.

Nuclear reactors are usually classified by *reactor design families* and *generations*. These classifications apply to GW-scale, SMR, and AMR reactors.

Nuclear reactor designs vary in their *generations* (Gen I, Gen II, Gen III, Gen III+ and Gen IV). These differ in terms of their design features, including the cooling mechanism, moderator, fuel form, enrichment and fuel cycle, among other things. *Cooling mechanisms* are central to the design as they remove the heat generated by fission reactions and ensure the controllability and safety of the reactor core. Likewise, *moderators* act as the medium in which the nuclear fuel is immersed, reducing the velocity of neutrons to sustain the fission chain reaction.

The current European nuclear fleet is dominated by Gen II and III designs, with Gen I reactors already retired in the EU. Gen III+ reactors have been or are currently being deployed and are the state-of-the-art type available at a commercial scale in Europe. Gen IV reactors are currently at the experimental stages and not available for commercial deployment, although some designs have reached operational or near-operational stages in other regions (e.g. China, Russia).

In terms of *reactor design families*, nuclear reactors are usually classified as follows:

- *Water-cooled reactors (WCRs)* use water as the reactor coolant and neutron moderator. These can be classified into:
    - *Light water reactors (LWRs), which use* ordinary (light) water as the coolant and moderator. LWRs use standard LEU (3-5%). They are the dominant

reactor design, comprising 82% of the global fleet, and almost all reactors in the EU. Depending on their specific designs, these can be Gen II, III or III+. Two subcategories of LWRs exist:

  - *Pressurised water reactors (PWRs)*, which use high-pressure water as a coolant and moderator. Heat is transferred to a non-reactive secondary loop where steam drives the turbine. PWRs are the most widespread LWR design in the EU and globally. Examples of Gen III+ PWRs include the *European Pressurised Reactor (EPR) (Electricité de France (EDF))*, the *AP1000 (Westinghouse)*, APR1400 (Korea Hydro & Nuclear Power (KHNP)), and the *VVER-1200 (Rosatom)*.

  - *Boiling water reactors (BWRs),* which use boiling water as the coolant and moderator. Unlike in PWRs, water in BWRs is allowed to boil directly inside the reactor core, generating steam that drives a turbine. BWR deployment in Europe is limited, with reactors operating only in Finland, Spain, Sweden and Switzerland. Examples include Gen II/III designs such as the *BWR-6 (General Electric)* and the *ASEA-II (ASEA-ATOM/ABB).*

- *Heavy water reactors (HWRs)*, which use heavy water (deuterium oxide) as a coolant/moderator. Heat in the core is transferred to a secondary loop to drive a turbine. Unlike other *reactor* types, HWRs can use forms of natural (unenriched) uranium as fuel. HWR operation in Europe is limited to the *CANDU (Atkins Réalis)* reactors operating in Romania.

- *Gas-cooled reactors (GCRs)* use circulating gas (e.g. helium) as a coolant instead of water. Heat is removed from the core and transferred to a heat exchanger, producing steam and driving a turbine. Using gas allows operation at higher temperatures and lower pressure, therefore improving thermal efficiency. Higher core outlet temperatures allow for more versatile non-electric applications of reactors. These can be classified into:

  - *Advanced gas-cooled reactors (AGRs),* which are Gen II designs that use carbon dioxide as a coolant gas, graphite as a moderator and LEU as a fuel. AGRs were principally commissioned in the UK but are nearing their phase-out.

  - *High-temperature gas-cooled reactors (HTGRs), which* use helium as a coolant gas, HALEU as a fuel, and are considered the most advanced Gen IV design, close to commercial deployment. Thus far, these have only been deployed in China in SMR format (HTR-PM), with no near-term plans for commercial deployment in Europe.

- *Molten salt reactors (MSRs)* mostly make use of nuclear fuel dissolved in a liquid-salt mixture, which circulates through the reactor and allows low-pressure operation. They are Gen IV and in the experimental stage of design. No MSRs have been deployed yet globally.

- *Liquid metal-cooled reactors (LMRs)* are fast-neutron reactors that, instead of using water or gas, implement liquid metal (e.g. sodium or lead) as a coolant in the core. Depending on the design, these reactors may use mixed oxide (MOX) fuel. Sub-categories include inter alia *sodium-cooled* fast *reactors (SFRs)*, *lead-cooled fast reactors (LFRs)*, and *lead-bismuth-cooled reactors (LBEs)*. These are considered Gen IV and have not yet been deployed in Europe. SFRs are only operational in Russia (BN-600 and BN-800 at the Beloyarsk nuclear power plant) and China (China Experimental Fast Reactor (CEFR)), and the LMR design (BREST-OD-300) is expected to begin operations in Russia in 2026.

Annex 3: Methodology (extended)

The analysis is based on a combination of desk research and targeted stakeholder engagement. Initial desk research was conducted between July and October 2025.

Stakeholder engagement included:

(i) two online expert workshops ('Nuclear energy: System value and economic viability in a decarbonised energy system' on 26 November 2025; 'Small modular reactors: technology, economics and deployment strategies,' on 19 January 2026)

(ii) two in-person roundtables ('How can nuclear get back on track in the EU? Finding a role in the decarbonised energy system – and what it takes to deliver new build' on 17 February 2026, and 'Does Europe have what it takes to deploy small modular reactors?' on 17 March 2026, jointly organised with CATF)

(iii) ad hoc bilateral expert discussions conducted throughout November 2025-March 2026.

The findings were further cross-validated with (i) the input from the three Member State reports (Romania, Czechia, and Poland), (ii) through the participation of the authors in an MIT-CATF Summer School (May 2026), and (iii) through two rounds of stakeholder and expert reviews in April and May 2026.

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