Financing the Energy Transition

Nuclear Memo

April 2024

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Executive summary

This report is the first in a series from JFI's Financing the Energy Transition initiative, pairing market analysis with levelized cost of energy modeling to give a high-level picture of the factors influencing the financing and bankability of green technologies.

Decarbonizing the global energy system will, in virtually every scenario, require leveraging nuclear power. At the recent COP28 climate conference, twenty-two countries called for a tripling of global nuclear capacity within the next 26 years. Yet in the United States (and Europe), the recent trend has been one of contraction, rather than expansion. A US and European nuclear renaissance faces several roadblocks. In this report, we highlight three: construction costs, visibility into the nuclear fuel cycle, and financing and offtake.

Construction costs for greenfield plants in the United States, when accounting for financing, dominate the levelized cost of nuclear energy, at 60 to 80 percent of the final levelized cost. Construction costs for recent projects in the US and Europe have been far higher than in the rest of the world, with plants completed well behind schedule and over budget. Some of these differences are attributable to a lack of recent nuclear construction experience, and could correct with learning effects. But others are due to differences in requirements for upstream components, a shifting regulatory landscape, and a lack of standardization; these factors may need to be addressed by policy.

On fuel, JFI modeling points to growing demand, with natural uranium and enrichment requirements growing at a roughly 3 percent annual rate between 2022 and 2030, and 2.5 percent thereafter. At present, Europe and the United States depend on geopolitically risky states, including Kazakhstan, Russia, Uzbekistan, and Niger, for approximately 55 percent of uranium supplies, and spare enrichment capacity is concentrated in Russia. In moderate growth scenarios, announced capacity expansions across the fuel cycle might be enough to moderate security-of-supply concerns, but a much more dramatic supply response will be needed to support a full-throated American and European nuclear revival.

The high upfront costs and long deployment timelines of nuclear power plants disproportionately expose these projects to prevailing financing conditions. We find that each 0.4 percentage point decrease in the weighted average cost of capital (WACC) produces a roughly 4 percentage point decrease in the total cost of power. This sensitivity points to a role for mechanisms such as concessionary lending, generous investment tax credits, and new multilateral financial institutions in bringing financing costs under control. Nuclear plant owners have struggled to turn a profit in deregulated power markets, where nuclear must compete against fossil plants that generate environmental externalities, and intermittent renewables that generate grid resilience and reliability externalities. Financing and offtake models used in other US and international contexts point to some potential solutions.

If these challenges can be met, JFI modeling suggests that, even with existing reactor designs, greenfield nuclear power plants can compete with alternative sources of clean, firm capacity, including renewables with battery storage and fossil plants equipped with carbon capture and storage.

Introduction

At last December's COP28 climate conference, twenty-two countries, heavily skewed toward early adopters of nuclear power such as the US, UK, France, and Japan, declared an ambitious goal to **triple global nuclear capacity by 2050.** Globally, the generation capacity (maximum power output) of the world's fleet of nuclear power plants is about **373 gigawatts** (GW) today. Tripling it by 2050 would imply building about **twenty-six** Vogtle-sized reactors every year between now and 2050 – a monumental undertaking.

The COP28 nuclear goal is well above the consensus outlook for nuclear power. In its last *World Energy Outlook*, published in June 2023, the International Energy Agency predicted that global nuclear capacity would only reach 622 GW by 2050. And S&P Global's forecast is in the same ballpark, calling for 631 GW of installed capacity.

Ironically, nuclear generation **declined 6 percent** over the last ten years in the twenty-eight countries that signed on to the nuclear goal. It has been the rest of the world – including relative newcomers to nuclear power, like China – where nuclear generation has been growing, and where it is expected to grow in the future.

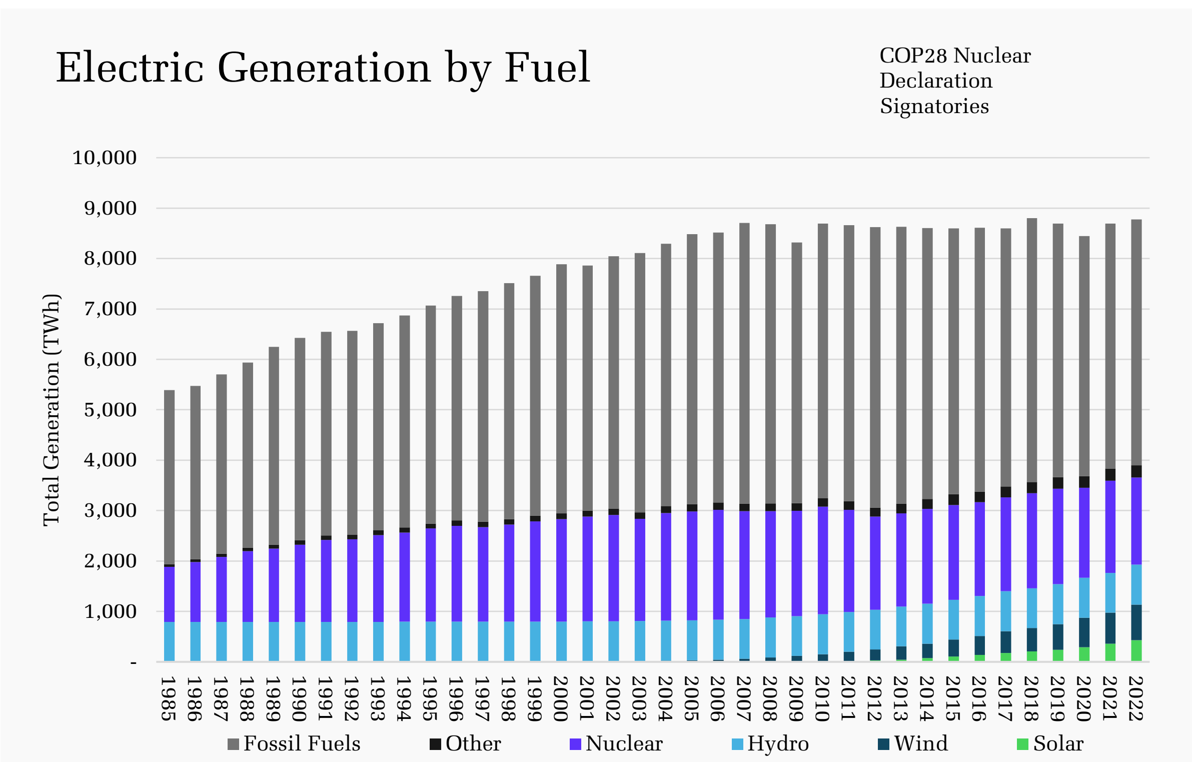

Figure 1 (Statistical Review of World Energy)

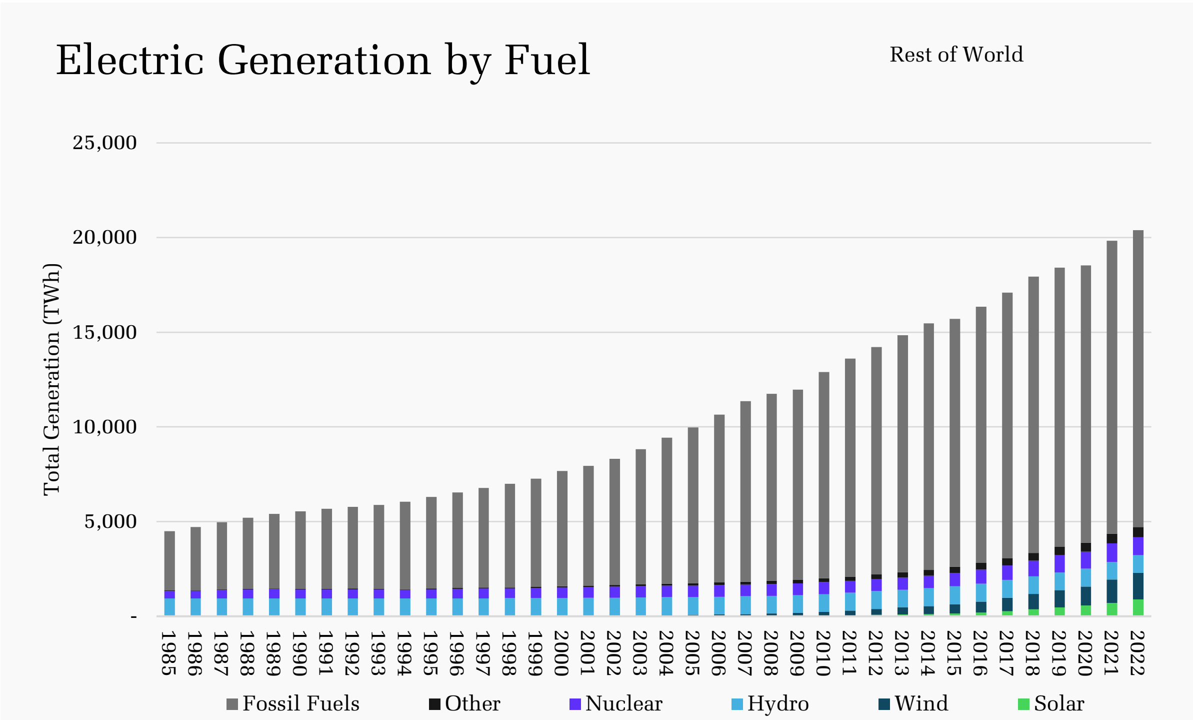

Figure 2 (Statistical Review of World Energy)

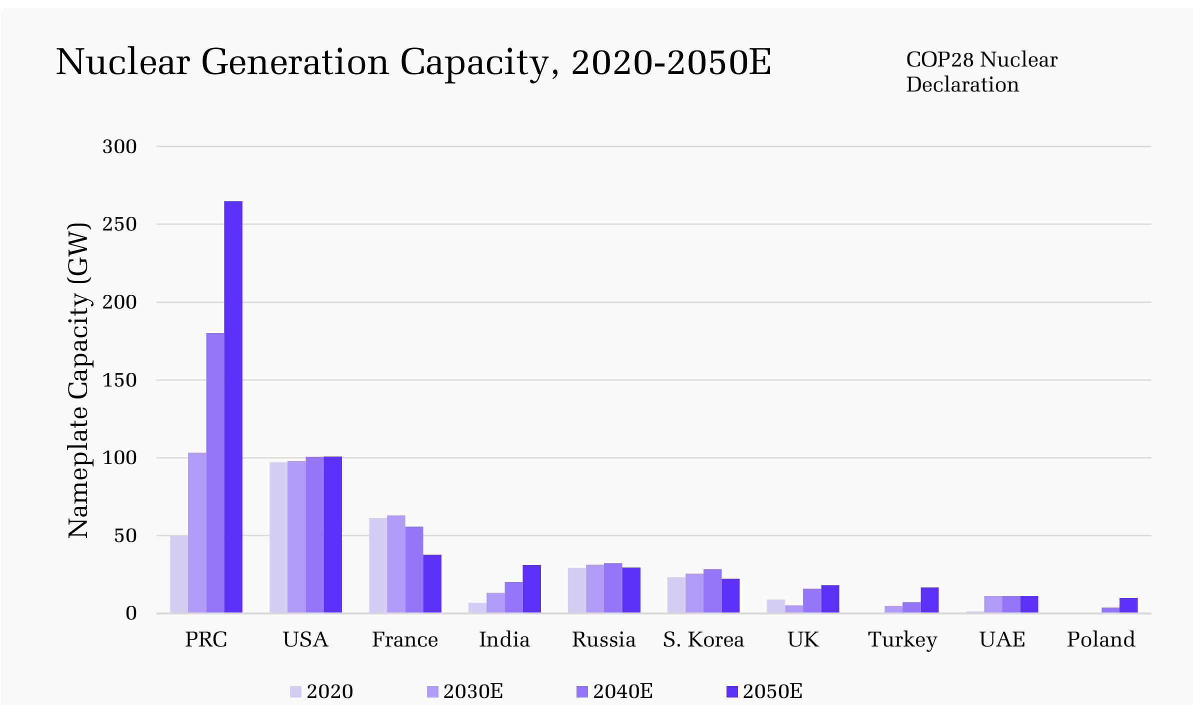

Figure 3 (S&P Global)

But it will be hard to close the gap between current trends and the COP28 declaration's lofty goals if the developing world has to go it alone. Extensive nuclear operating experience, utilities with access to low-cost financing, and a widely shared political commitment to net zero mean that the OECD member countries can also contribute to the nuclear energy renaissance.

The major challenge in decarbonizing electric power is not getting to a 10 or 20 percent share of power coming from "variable renewables" like solar and wind, but **building out a range of low-carbon resources that can provide firm capacity.** The "value factor" of resources like wind – the economic value of the power they generate relative to a "flat block" of power with constant output over a 24-hour day – degrades as their share of generation increases.

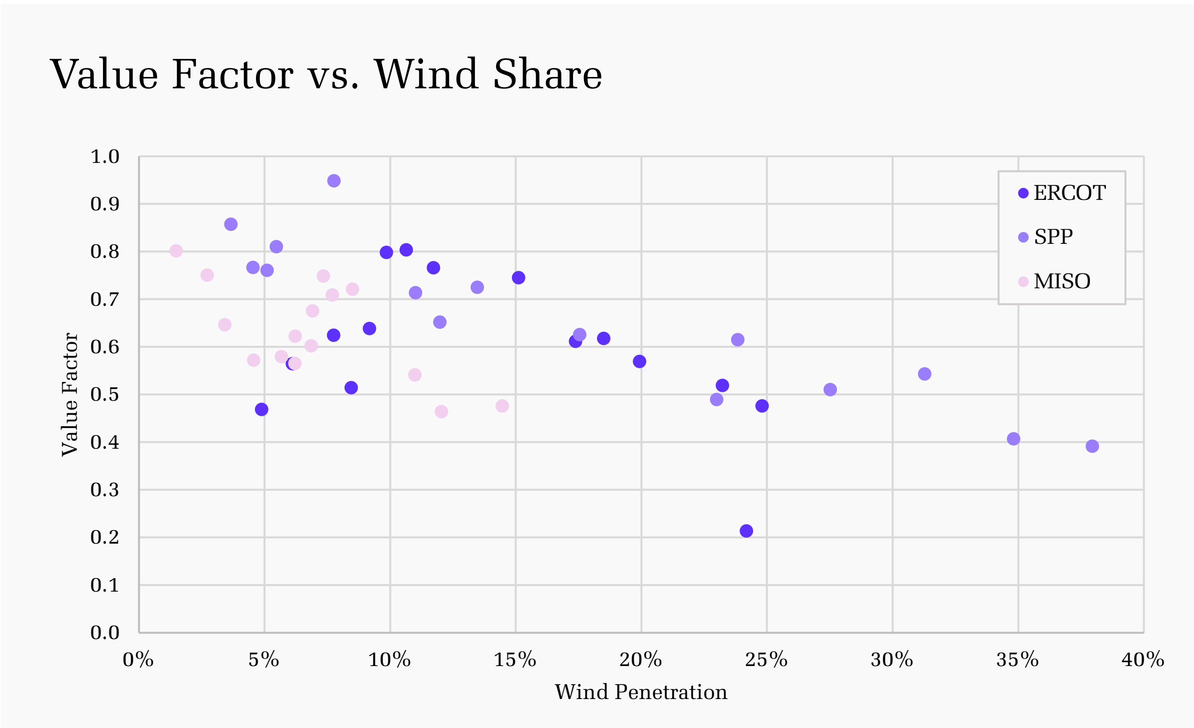

Figure 4 (DOE Wind Technologies Office)

Backup sources of firm generation capacity – whether lithium-ion batteries, long-duration energy storage ("LDES"), nuclear power, or gas peaking plants equipped with carbon capture and storage ("CCS") – will be needed even in a deeply decarbonized grid in order to solve the basic trilemma of delivering **clean, reliable, and affordable power.**

JFI's modeling work suggests that, even with existing reactor designs, **greenfield nuclear power plants can be a competitive source of clean, firm power in the US.** "Levelized cost of energy" (LCOE) estimates, which compare the lifetime costs of newly built power assets, have been widely criticized for overstating the case for solar and wind (which, in any event, have to compete against the **marginal cost** of existing fossil capacity, as well as the lifetime cost of new combined-cycle gas plants). But comparing apples to apples – clean, firm sources of power, with cost estimates rooted in the US context (see technical appendix for detailed assumptions) – shows that nuclear power has at least as much of a "right to win" in the electric power market of the future as storage-equipped renewables and CCS. It also has additional advantages (limited land use impacts, and by far the lowest **life-cycle emissions impact**).

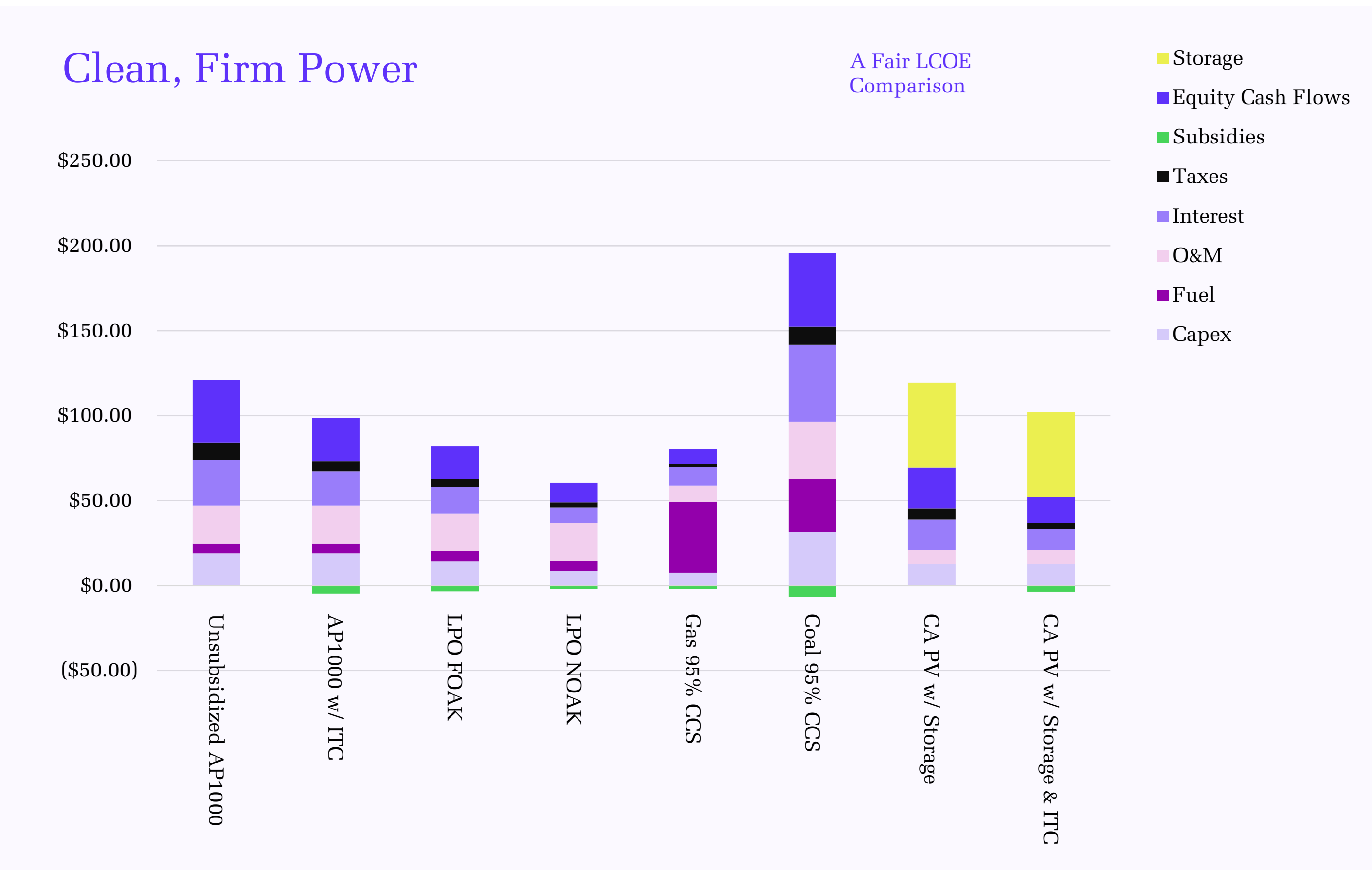

Figure 5 (JFI LCOE Modeling; CAISO Storage Cost from Lazard)

Two major barriers stand in the way of growing the nuclear power sector in North America and Europe.

First, construction delays and cost overruns have been a chronic problem since the mid-to-late 1970s. Recent projects in these regions – the Vogtle plant in Georgia, Olkiluoto 3 in Finland, and Flamanville-3 in France – have been ruinous. And yet, costs in other regions (South Korea, China, and the United

Arab Emirates among them) are more than 75 percent below levels in the West. One view is that lower costs in emerging markets, driven by cheaper labor, can't be replicated in the United States or Europe. Our view, drawing on the academic literature on nuclear construction, is cautiously optimistic. Capital costs of $8,000 to $10,000 per kW seem readily achievable, a level at which some combination of subsidies, concessional finance, and demand from industrial customers for 24/7 clean power makes new-build nuclear plants viable.

Second is an issue that is not *currently* a major problem for reinvigorating nuclear power, but one that will require investment to stay that way – ensuring affordable and secure supplies of **uranium and nuclear fuel services.** Nuclear fuel costs, at $5 to $7 per MWh, are so low relative to the overall cost of nuclear power that short run demand is almost perfectly inelastic.[1] Moreover, JFI estimates that over half of US and European uranium supplies come from regions with significant geopolitical risk (Russia, Uzbekistan, Kazakhstan, and Niger). The vast majority of the world's spare enrichment capacity is in Russia as well, and a bill is making its way through the US Senate that would ban the import of Russian uranium.[2] With global demand set to grow over the next two decades, it will be key to incentivize investment in mining and enrichment projects that can help limit these risks to the nuclear power sector.

Third, and finally, making new nuclear power plants "bankable" presents unique challenges. The higher interest rate environment of the last two years is also a headwind, as nuclear power plants, with a cost structure skewed toward upfront construction costs, are highly sensitive to the cost of capital. Moreover, restructured electricity markets have not been kind to nuclear power plant operators, which have struggled to break even in much of the US. Amazon's recent purchase of a data center co-located with the Susquehanna Steam Electric Plant, and the recently announced alliance between Google, Microsoft, and steelmaker Nucor to procure clean, firm power point to new opportunities for generator owners in deregulated markets to find offtake partners on a multi-gigawatt scale.

[1] This point will be fleshed out in greater detail below. Illustratively, in the US context, the price of power is set by the marginal cost of gas generation, which, at gas prices of $3 to 4 per million btu, is $30 to 40 per MWh. For a nuclear plant operator, these power prices are well above their short run breakeven. Fuel prices would have to increase five to six-fold for the plant to lose money on burning the marginal fuel rod. But, factoring in operating and maintenance costs averaging over $16 per MWh in 2022, not to mention interest and a return on equity, the long-run breakeven point for nuclear is far higher.

While utilities protect themselves against the risk of sudden price increases through long-term contracting, the somewhat counterintuitive dynamics of power markets mean that it is possible for the price of uranium and fuel services to cut into plant operating margins substantially.

[2] Effectively a ban on the procurement of Russian enrichment services, since Russia is a far more important player in the enrichment market than the uranium market *per se*.

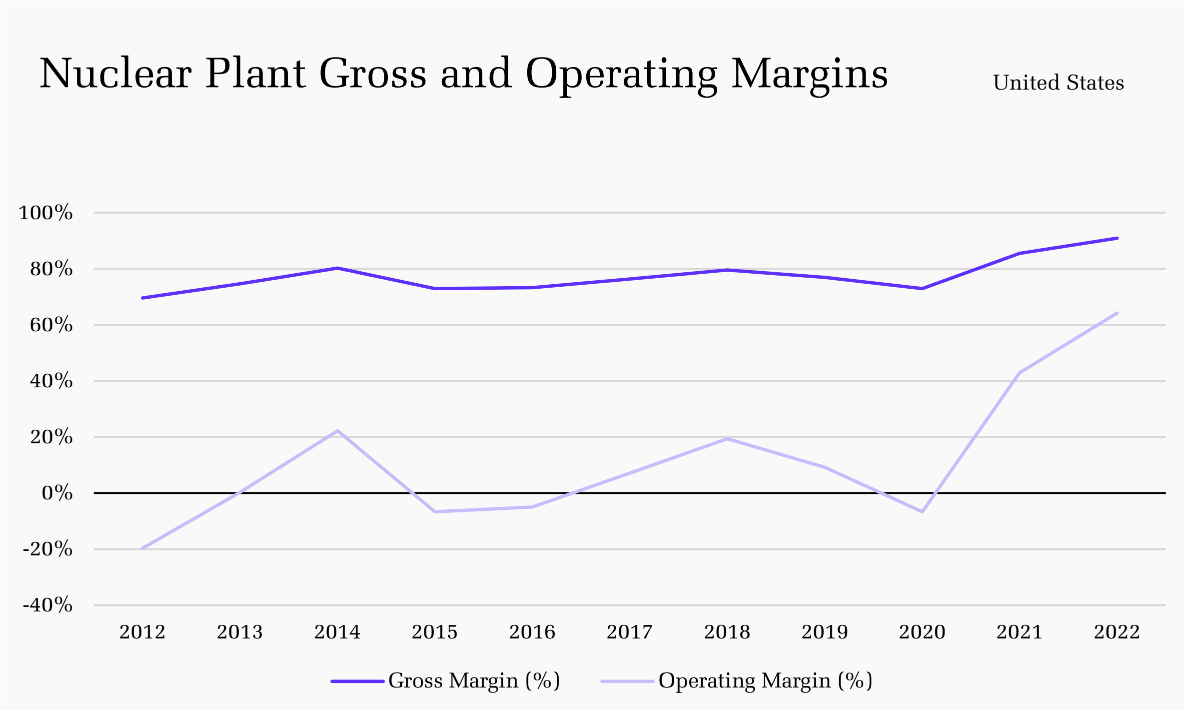

Figure 6 (Bloomberg New Energy Finance)

Cross-cutting all these themes is one goal: **to make the nuclear power value chain investable.** We are in a new world of climate policy, one that has traded "sticks" (taxes and penalties for fossil fuel users) for the "carrots" of green industrial policy. The dominant mode of green industrial policy is to provide **catalytic capital** – tax credits and subsidized finance that have a multiplier effect, enticing private capital to come in and build out low-carbon infrastructure as technologies mature and risks become "known unknowns."

In this report, we highlight some of the key challenges holding utilities and investors back from investing in the global (and, especially, American) nuclear power renaissance: **construction costs, visibility into the nuclear fuel cycle,** and **bankability** (by which we mean not just financing costs, but interrelated issues of securing off-take agreements and cost guarantees from suppliers).

The cost structure of nuclear power

The costs of power generation technologies are frequently compared using the concept of "levelized cost," or LCOE, widely popularized by the investment bank Lazard's annual reports comparing costs across different power resources. LCOE is especially useful for comparing the **lifetime average costs** of **new power plants.** It is important to note that LCOE reflects the **long-run breakeven cost** of a power plant – the revenue it will need to earn, divided by the total amount of power it generates, that will allow its owners to pay off the loans they incurred to build it, and to earn an appropriate, risk-adjusted return on the equity capital they invested into the project. **Power prices are not set based on the LCOE of different generators, however,**[3] but rather, based on the **marginal cost of the last, most expensive, and inefficient generator called into service** in order to meet demand.

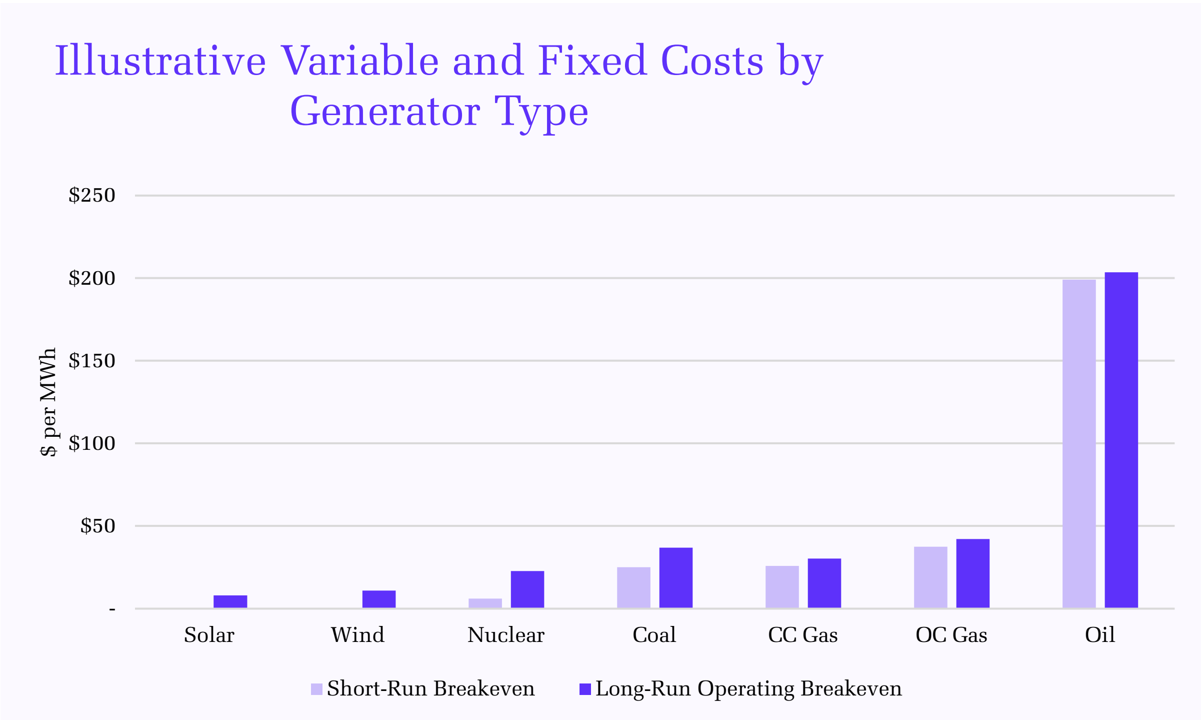

Figure 7 (JFI Modeling)

Illustratively, in the United States, combined cycle gas plants are the workhorses of most electricity markets. With heat rates below 8,000 btu of fuel per kWh of electricity generated, and gas prices between $3 and $4 per million btu, combined-cycle gas is highly efficient and comes with a "fuel

[3] Except, de facto, in traditional, cost-of-service regulation.

cost" (effectively, the marginal cost) of roughly $22 to 31 per MWh. With fuel costs of just $5 to 7 per MWh, a nuclear power plant is always incentivized to keep running **over the short run** in order to defray large operating expenses (some $17 per MWh, on average, in 2022) and debt service (and eke out a return for shareholders).

As the BNEF data above illustrates, this means that, at least in the US, it has been very hard for nuclear plants operating in deregulated markets to earn an operating profit, let alone distribute capital to equity investors, in recent years, as the shale revolution brought abundant supplies of cheap natural gas and the fossil generation fleet became dominated by cheap natural gas. This situation was reversed, however, with the passage of the Inflation Reduction Act (IRA), which includes a production tax credit (PTC) for existing nuclear plants – which, to make a long story short, sets an effective floor under the average price realized by nuclear generators, at over $40 per MWh.

JFI estimates that the lifetime cost of power from an **unsubsidized AP1000 project in the US** (based on a project case study used by the Energy Information Administration, or EIA, in preparing its Annual Energy Outlook) is **$121 per MWh.** With a 30 percent investment tax credit (ITC), this would fall to **$94 per MWh.**

These costs may appear high, but it's important to note what the costs of solar, wind and fossil fuels leave out – the cost of solar and wind's **intermittency,** and the cost of a large negative externality not reflected in either the marginal cost or LCOE of fossil fuels. Lazard estimates that, in California, storage would add $50 per MWh to the cost of a solar project. A $100 per tonne carbon tax would add **$40 per MWh** to the cost of power from a combined-cycle gas plant and **nearly $100 per MWh** to the cost of power from a steam-based coal plant.[4]

[4] Based on EIA reference emissions intensities of 52.91 and 98.02 kg CO_2 per mmbtu, and heat rates of 7,500 and 10,000 btu per kWh, respectively.

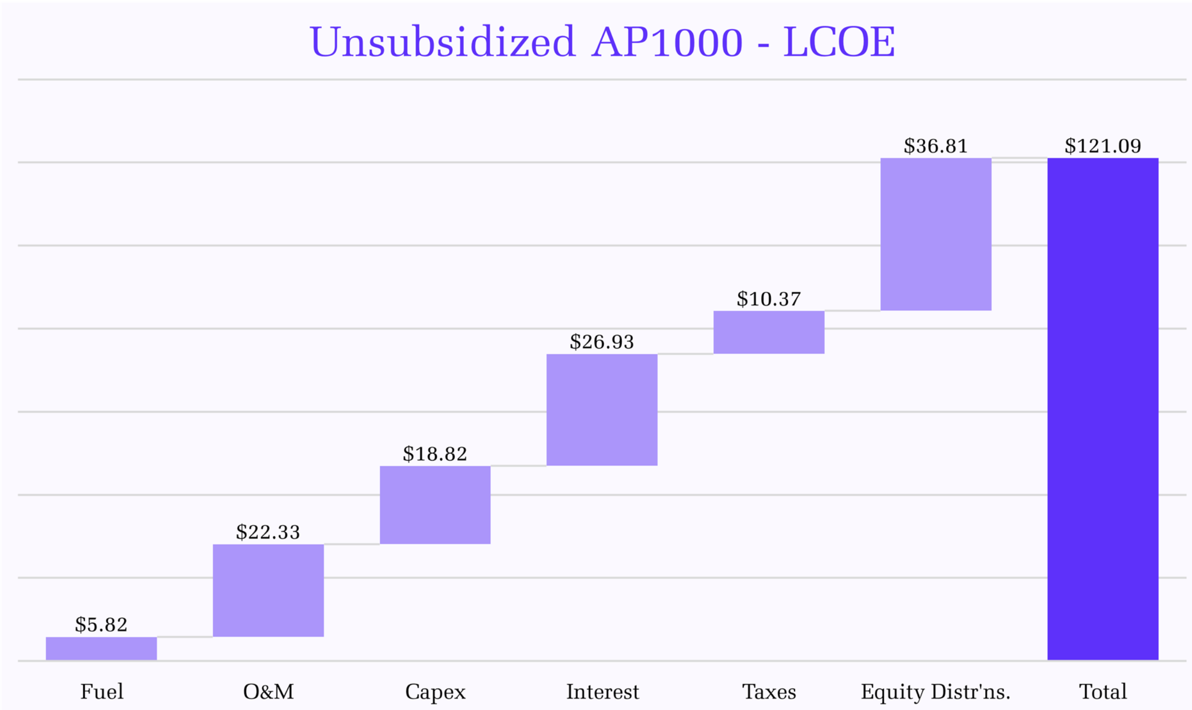

Figure 8 (JFI Modeling)

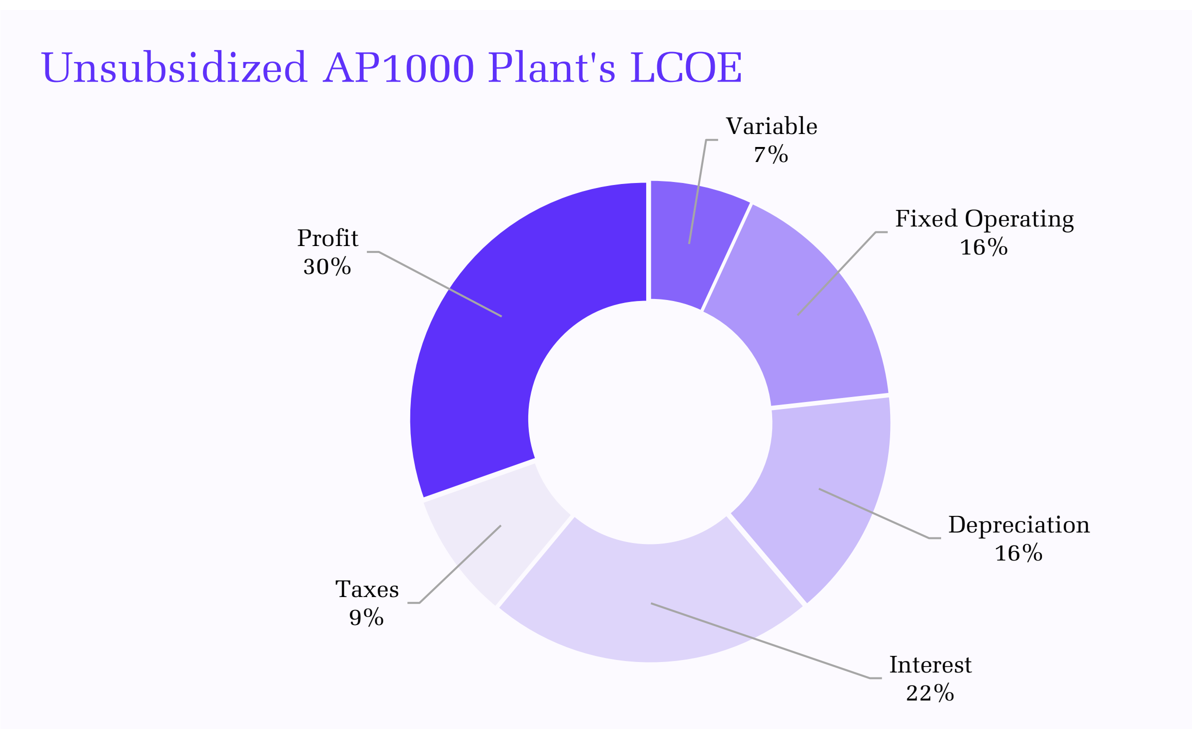

Figure 9 (JFI Modeling)

The high fixed costs and low variable costs of nuclear power are aligned with the typical strategy of operating nuclear plants as **"baseload" sources of power** – generating power throughout the day, rather than ramping output up and down as demand increases and decreases ("load following"). Most of the fundamental issues around scaling nuclear power revolve follow from its cost structure.

Once a nuclear plant has been built, it pays, at least over the short run, for its operator to run it as often as possible. The difficulty of recovering stranded costs means that this short run dynamic bleeds into the long run. And, over the long run, without a long-term, offtake agreement, or the ability to recoup costs through higher rates levied on all of a grid's users, in a traditional cost-of-service regulatory model, the operator is at the mercy of the electricity market – where prices are often set by plants that don't have to defray anywhere near the level of fixed costs that nuclear plants do.

Construction costs

Like other low-carbon power sources, the cost of generating electricity from nuclear power is ultimately driven by plant construction costs. While depreciating the initial construction cost of a nuclear plant is optically only a small share of nuclear costs (16 percent in the illustrative AP1000 case study presented above), **construction costs also drive financing costs,** since developers (typically utilities) use a mix of debt and equity financing to fund the project. **Add up all of these costs, and construction totals 60 to 80 percent of the final cost of electricity from nuclear power.**

Recent build-outs in the West have ranged from $7,500 to $10,000 per kW (in nominal dollars at current exchange rates), ranging from 1.8x to 4.4x originally budgeted costs. Construction timelines have also ballooned, with the Flamanville-3 and Olkiluoto-3 projects, both based on the "European Pressure Reactor" (EPR) design, taking roughly **16 years** to complete from the beginning of construction to first criticality.

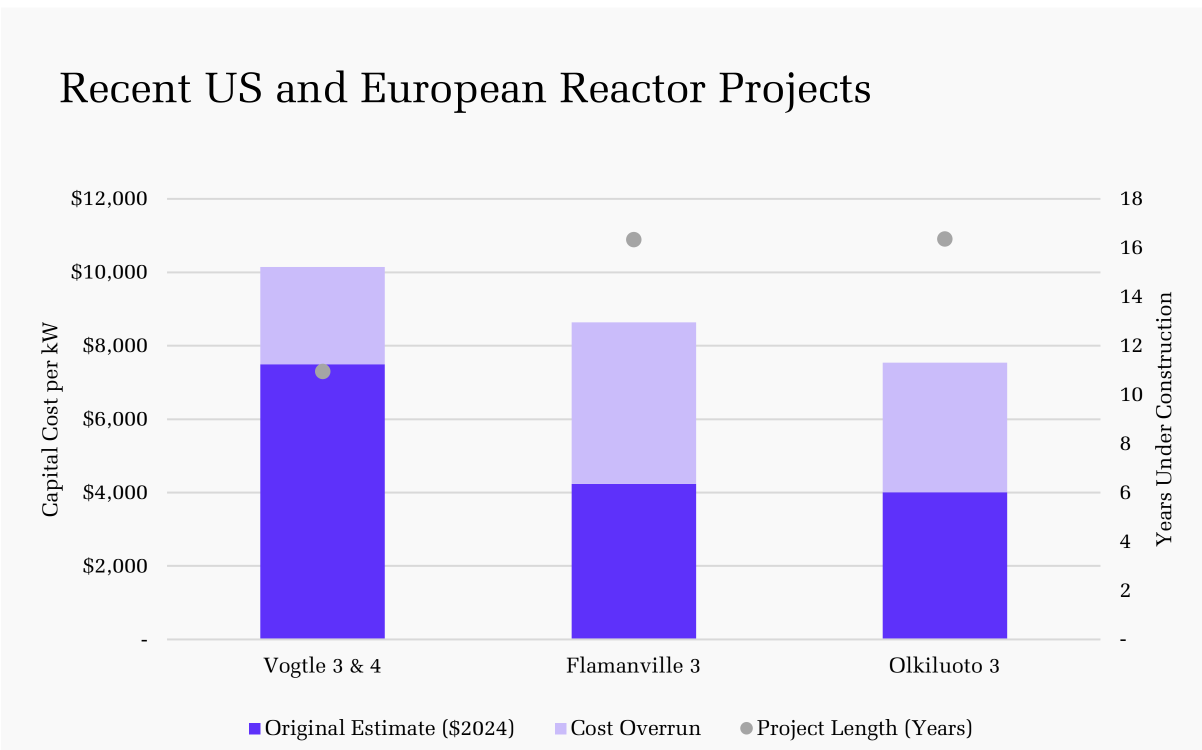

Figure 10 (Various Sources)

What is somewhat remarkable, and worth drawing out, is that if these EPR reactors were transported to the United States, in 2024, with operating and maintenance costs in line with Sargent and Lundy's estimates for large-scale new nuclear, used in the EIA's *Annual Energy Outlook* modeling, and delivered **on time and on budget,**[5] they would be able to generate power at a cost of **$61 to 63 per MWh** – easily competitive with greenfield gas projects, **even before including the investment tax credit.**

And, in fact, capital costs for new reactors in South Korea, China, and the UAE, based on both light-water reactor (LWR) and pressurized water reactor (PWR) designs, are in the low $1,000s (per kW) range originally estimated for the ill-fated French and Finnish projects. **Notably, this includes numerous examples of the reactor designs used in the Vogtle project, the Westinghouse AP1000** (16 reactors operating and under construction in China and India) **and in the European projects, the EPR** (Taishan 1 and 2).

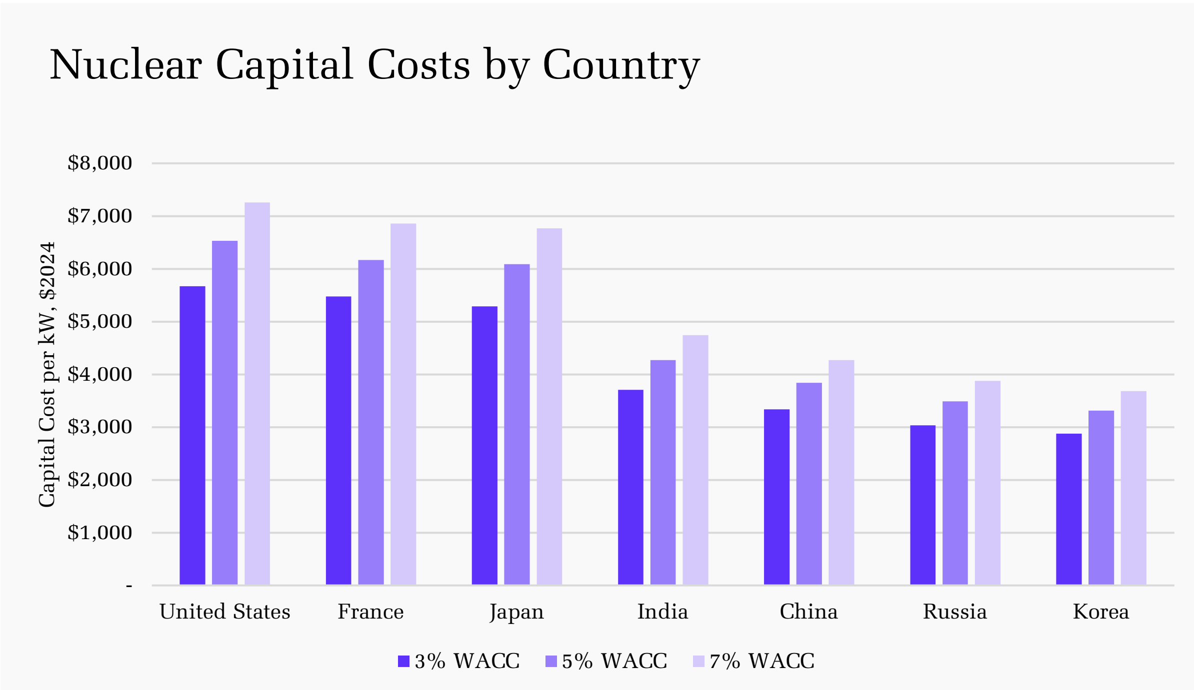

Figure 11 (OECD Nuclear Energy Agency)

Even if reported cost estimates for South Korean projects built using Korea Electric Power Company's (KEPCO) APR1400 reactor design are lower, KEPCO is building the UAE's Barakah power plant (believed to be a more reliable data point) at a nominal cost of under $5,000 per kW. Comparing the APR1400 to recent Western projects makes for a useful case study in benchmarking nuclear construction costs.

[5] Updating their originally budgeted construction costs using the EUR/USD exchange rate prevailing when construction began, and adjusting for inflation using US CPI.

The Three Mile Island effect

An increasingly complex regulatory environment and decades of degrading expertise across the supply chain have caused ballooning construction timelines and costs.

Since the Three Mile Island partial meltdown in 1979, the United States has increased regulations aimed at managing the risks of nuclear power. Investment in essential manufacturing and skilled labor expertise atrophied across the supply chain. Due to both the added regulatory burden and operational problems, construction times have tripled in the US since the incident.

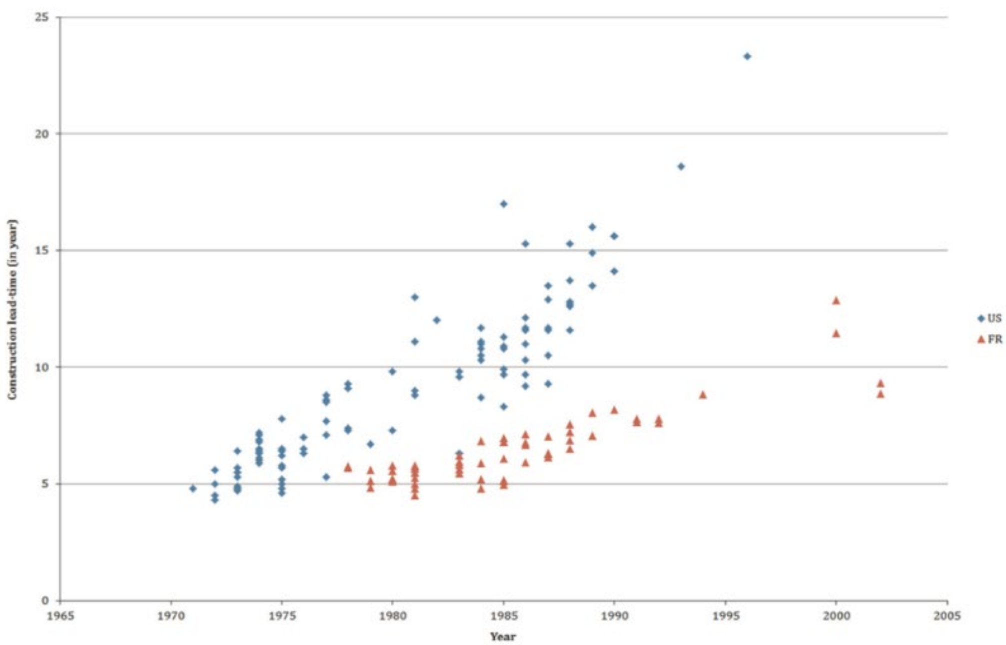

Figure 12 (Construction lead-time (right) in the US (blue) and France (red). Berthélemy and Escobar-Rangel)

Complex regulation in an industry can both introduce risk aversion and slow potential learning effects. Berthélemy and Escobar-Rangel (and others) found that incremental innovation in the nuclear energy industry in the US and France has increased the complexity and costs of nuclear reactors – in other words, produced negative learning rates. **Innovation has been aimed at meeting increasingly complex safety regulations, at the expense of efficiency**. Lovering *et al.* call this the "Three Mile Island effect" (TMI effect) and show that the phenomenon is most extreme in the US.

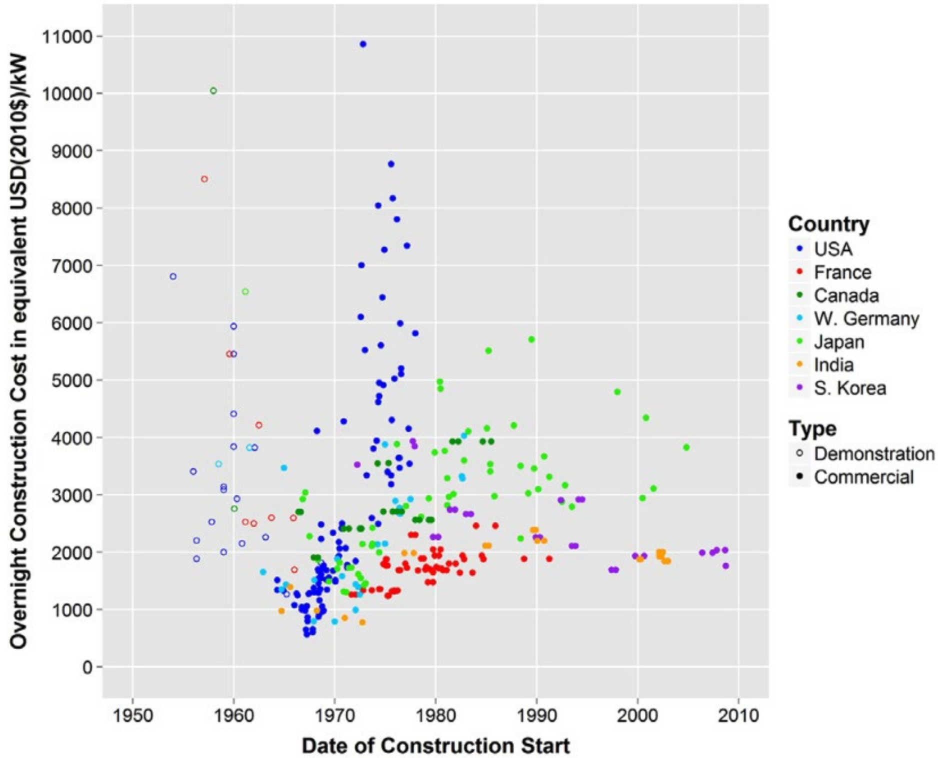

Figure 13 (Lovering et al., *"Overnight Construction Costs of Global Nuclear Reactors in USD2010. Costs are adjusted by local GDP deflator and to USD at 2010 market exchange rates.")*

Proper regulation is essential, to be sure, and modern reactor designs are much safer than the earlier builds. However, the regulatory environment in the US nuclear industry has become onerous and inefficient. Unlike other sensitive industries (including jet engines and pharmaceuticals) nuclear energy in the US is now regulated at all development and deployment stages, including design, construction, and operation.

Materials sourced for nuclear projects face a "nuclear premium" due to quality control requirements that can significantly increase component costs relative to industrial-grade costs. Dawson (2017) estimates that the premium entails 23 percent of concrete costs and 41 percent of structural steel costs.

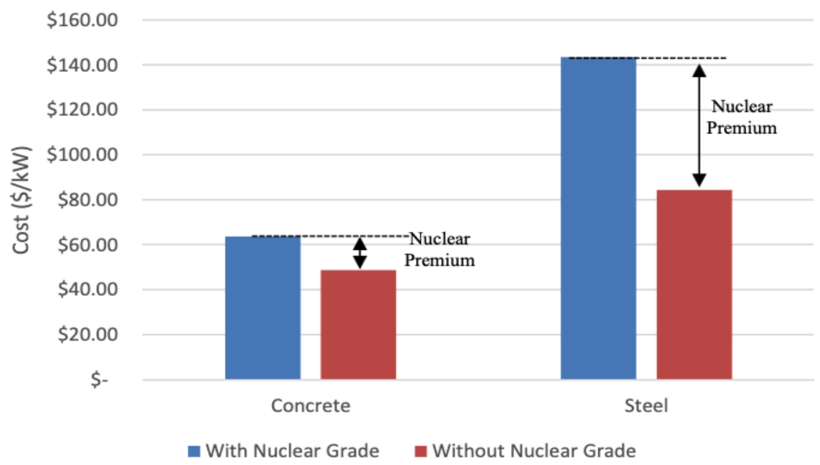

Figure 14 (Commodity cost considering nuclear premium and excluding nuclear premium. Dawson)

The modern US nuclear industry suffers from exceptionally high material and labor costs compared to other industries, which has been exacerbated by decades of degrading experience across value chains. [Eash-Gates *et al.*] study five decades of reactor construction data in the US and find that labor inefficiencies and escalating containment costs have been the central drivers of cost overruns. Additionally, the authors show how the TMI effect has translated into nuclear construction productivity losses.

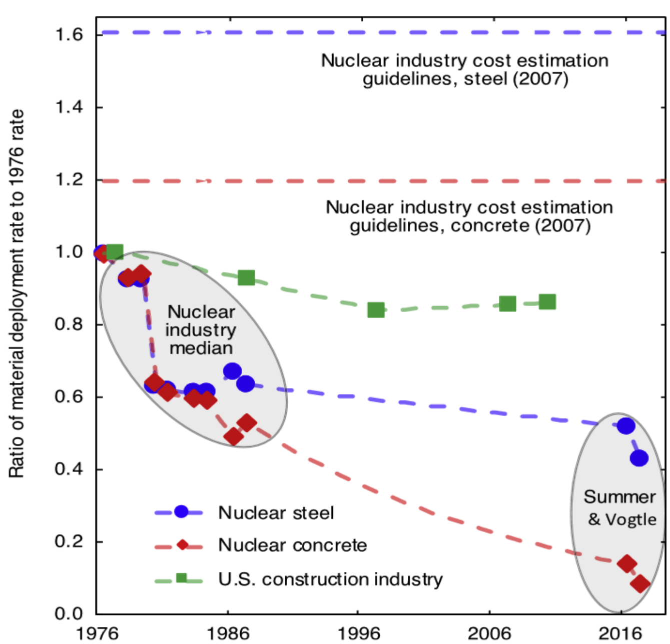

Figure 15 (Historical Construction Productivity Change in the Nuclear Industry and at Large. Eash-Gates et al.)

The US nuclear industry of today is equipped with a broad menu of ultra-safe reactor designs but lacks the expertise to actually *build* these designs. To reinvigorate the US nuclear industry, we must look to South Korea, which achieves not only the lowest overnight costs but also the shortest construction times globally *(note in the chart below that the UAE's sole nuclear power station was built by KEPCO using the Korean APR1400 design).*

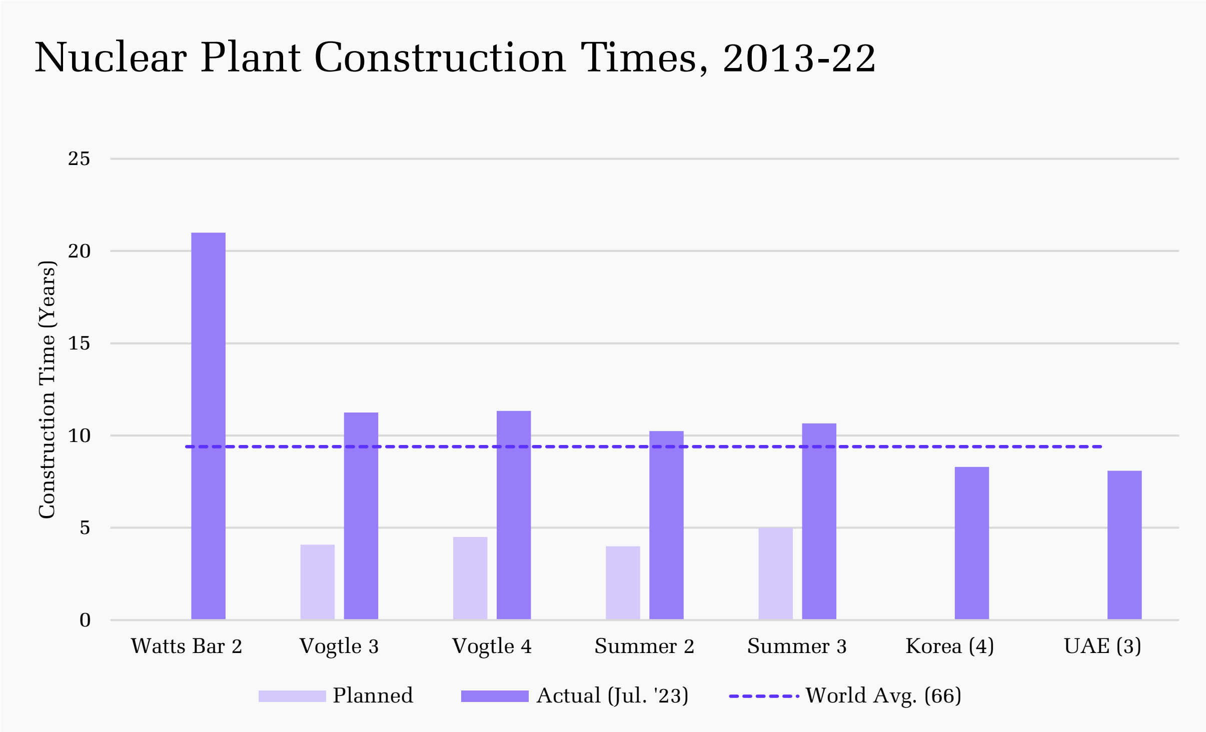

Figure 16 (Statista)

The need for standardization

KEPCO's experience shows that standardization can reduce construction costs. Many of these efficiencies can be replicated in the US, even with the headwind of persistently higher labor costs.

Academic research on plant construction costs suggests that the difference in costs between the Vogtle project and KEPCO's Barakah plant (built in the UAE using the South Korean APR1400 design) is almost entirely attributable to higher "yard, cooling, and installation" and owner's costs (e.g. land, permitting, project management). An MIT study found these two drivers alone explain **nearly 90 percent of the difference in cost between the Vogtle plant** (using then-current construction cost estimates).

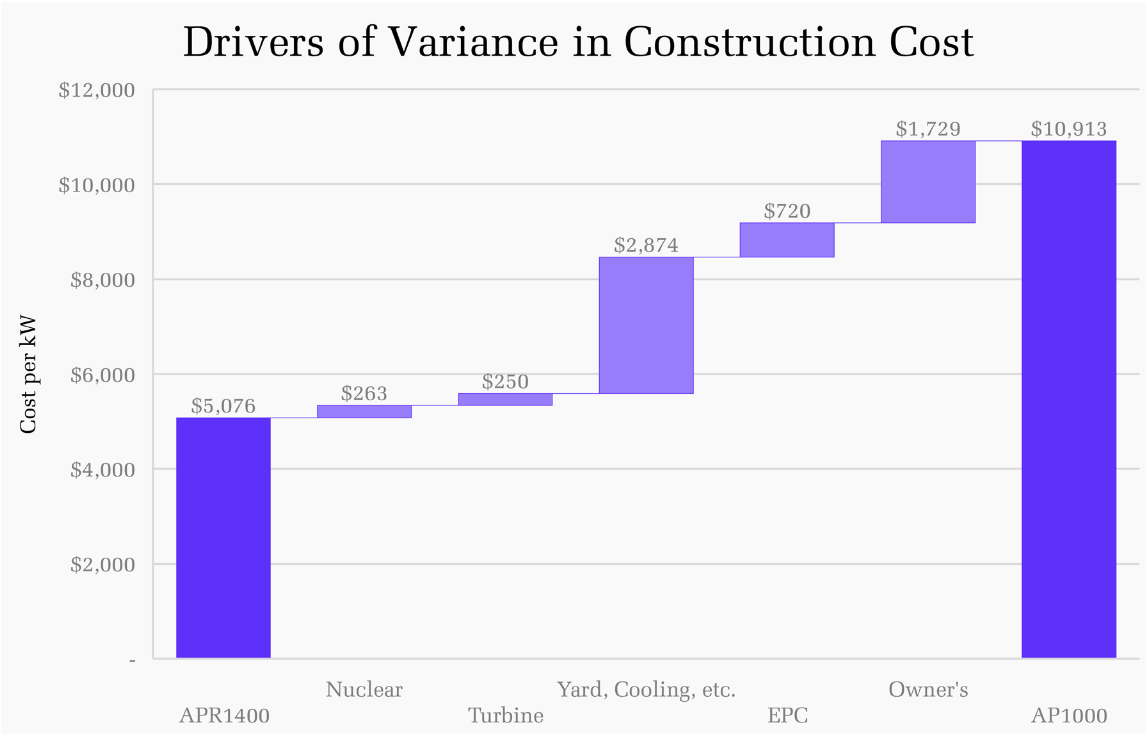

Figure 17 (Illustrative cost estimates based on MIT 2018, adjusted for inflation. Not intended to sum with illustrative AP1000 or actual Vogtle cost figures presented above.)

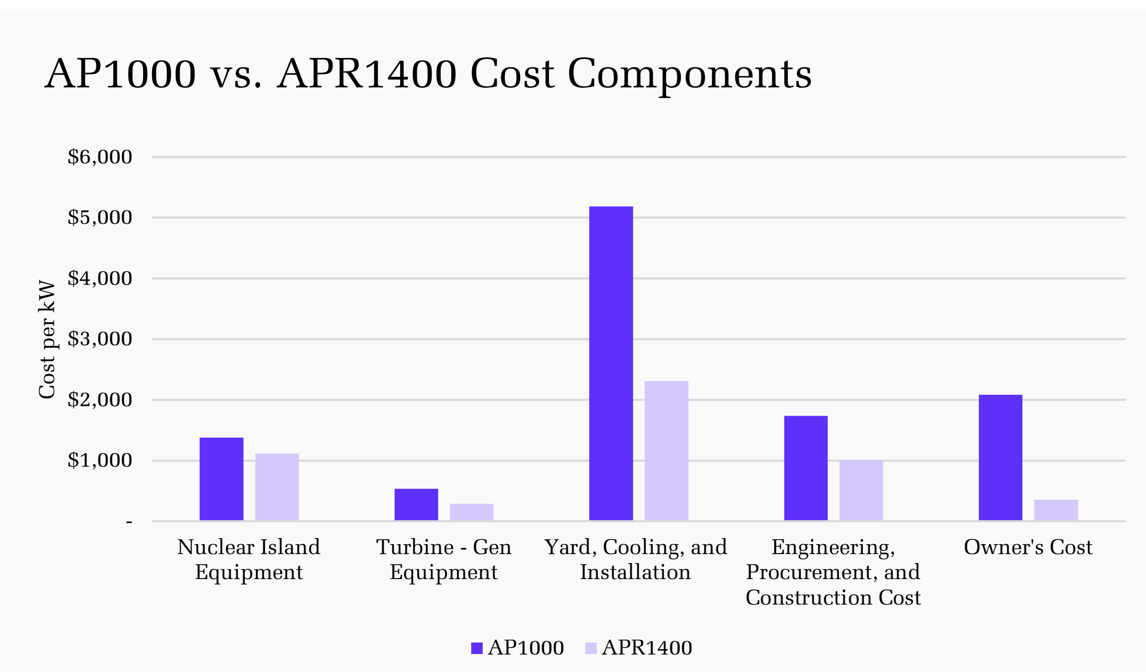

Figure 18 (Illustrative cost estimates based on MIT 2018, adjusted for inflation. Not intended to sum with illustrative AP1000 or actual Vogtle cost figures presented above.)

Labor costs in South Korea are indeed around half those in the US on average, but KEPCO (the vertically integrated utility building South Korean reactor designs) also simply spends less time (and labor) building new reactors. They achieve shorter construction times and lower costs through **standardization**. Recent reactor builds in the US are essentially first-of-a-kind (FOAK) projects, which are typically 30 percent more expensive than following plants of the same design – potentially even higher. Firms need to establish or rebuild expertise and single-unit projects carry the full costs (such as licensing and site development) compared to multi-unit reactor projects.

KEPCO, by contrast, builds complete standardized designs at many different sites, allowing learning across each unit. It also builds multiple units at the same site continuously, with the same suppliers and labor at each unit, reducing costs for mobilization or restarting component production.

Strategies like these are no secret – Berthélemy and Escobar-Rangel also found that standardization in the French fleet, and vertical integration across design, construction, and generation, enabled cost reduction through learning-by-doing and originally enabled France to become a global leader in nuclear energy generation. Conversely, diversity in reactor models causes delays due to supply chain constraints and increased regulatory workload (i.e. the US today: plenty of reactor designs and little experience executing).

To reduce reactor construction costs, of all sizes, the US must simultaneously (i) learn from the mistakes of the Vogtle builds and (ii) emulate KEPCO's success across four categories (as highlighted by The Nuclear Energy Agency): 1) design and supply chain maturity, 2) effective project management, 3) regulation stability and predictability, and 4) policy frameworks.

1) Design and Supply Chain

Vogtle AP1000

- Launched with **incomplete designs**, necessitating significant design adjustments and rework.[6]
- **Relaunched a domestic nuclear supply chain using facilities and contractors without prior nuclear industry experience**. The main construction contractor, Stone & Webster, was an engineering firm from the oil sector without nuclear experience.
- Adopted new construction methods that emphasized off-site construction and the transportation of large, prefabricated modules.

KEPCO APR1400

- Projects have **70-80% of the detailed design completed** before they are launched.
- Active nuclear programs have **enabled robust domestic supply chains** and industry-wide learning.

[6] The timing of US tax credits for nuclear new-build projects incentivized operators to accelerate steps with an incomplete design.

2) Project Management

Vogtle AP1000

- Stone & Webster's inexperience caused quality assurance and project management issues; conflict led to litigation and delays.
- **Fixed-cost contracts placed undue construction risk** on the EPC consortium between Westinghouse (the contractor) and the plant owners (the electric utilities).
- Westinghouse acquired S&W's parent company CB&I, **aiming to mitigate disputes** and enhance project control. This decision **eventually led to its bankruptcy.**

KEPCO APR1400

- **Design development and construction were vertically integrated** under an electric power utility.
- Collaboration with key partners in design and construction **clearly defined roles and responsibilities** that were implemented with efficiency and underpinned by regulatory safety standards.

3) Safety Regulation

Vogtle AP1000

- In 2009, the Nuclear Regulatory Commission introduced a new standard for shield-building requirements, **seven years after Westinghouse had applied for approval of its AP1000 design**.
- Resulted in unanticipated engineering challenges at a late stage of project planning.
- Took two years for Westinghouse to meet the new requirements, adding to delays and cost overruns.

KEPCO APR1400

- Achieved design approval from the regulatory agency **within five months**.
- The regulatory process was expedited through a standardized design approval system established under the **2001 Atomic Energy Act**; which set forth a simplified procedure characterizing **repetitive use of a certified design and grants designs a ten-year legal validity.**
- The Act and project management enabled a preliminary review system to synchronize design efforts with regulatory checks while integrating learning from past experiences.

4) Policy Framework

United States

- An uncertain and changing policy environment stifles the industry's ability to construct cost-competitive projects.
- Policies fail to support the proper development of manufacturing and skilled labor expertise.

South Korea

- Supports the construction of a series of plants, which realize cost savings from learning.
- Policies properly reduce contractor risk and ensure that nuclear supply chains are maintained.

The two cost areas driving much of the variance between AP1000 and APR1400 costs – yard, cooling and installation (YCI) and engineering, procurement and construction (EPC) – could see cost reductions of 40 to 50 percent from “first of a kind” to “Nth of a kind” reactor projects, per the Department of Energy’s Advanced Nuclear Lift-Off Report. Each 5 percent reduction in these costs translates to a roughly **$3 per MWh** reduction in levelized costs, and getting all the way to a 50 percent reduction in these costs would take the **unsubsidized** cost of power from a new AP1000 reactor from **$113 per MWh** to **$90 per MWh,** a 20 percent reduction in lifetime costs.

With a 30 percent investment tax credit, and access to lower-cost debt from the DOE’s Loan Programs Office (LPO), reduction in these cost areas alone could drive nuclear costs to as low as $74 per MWh.

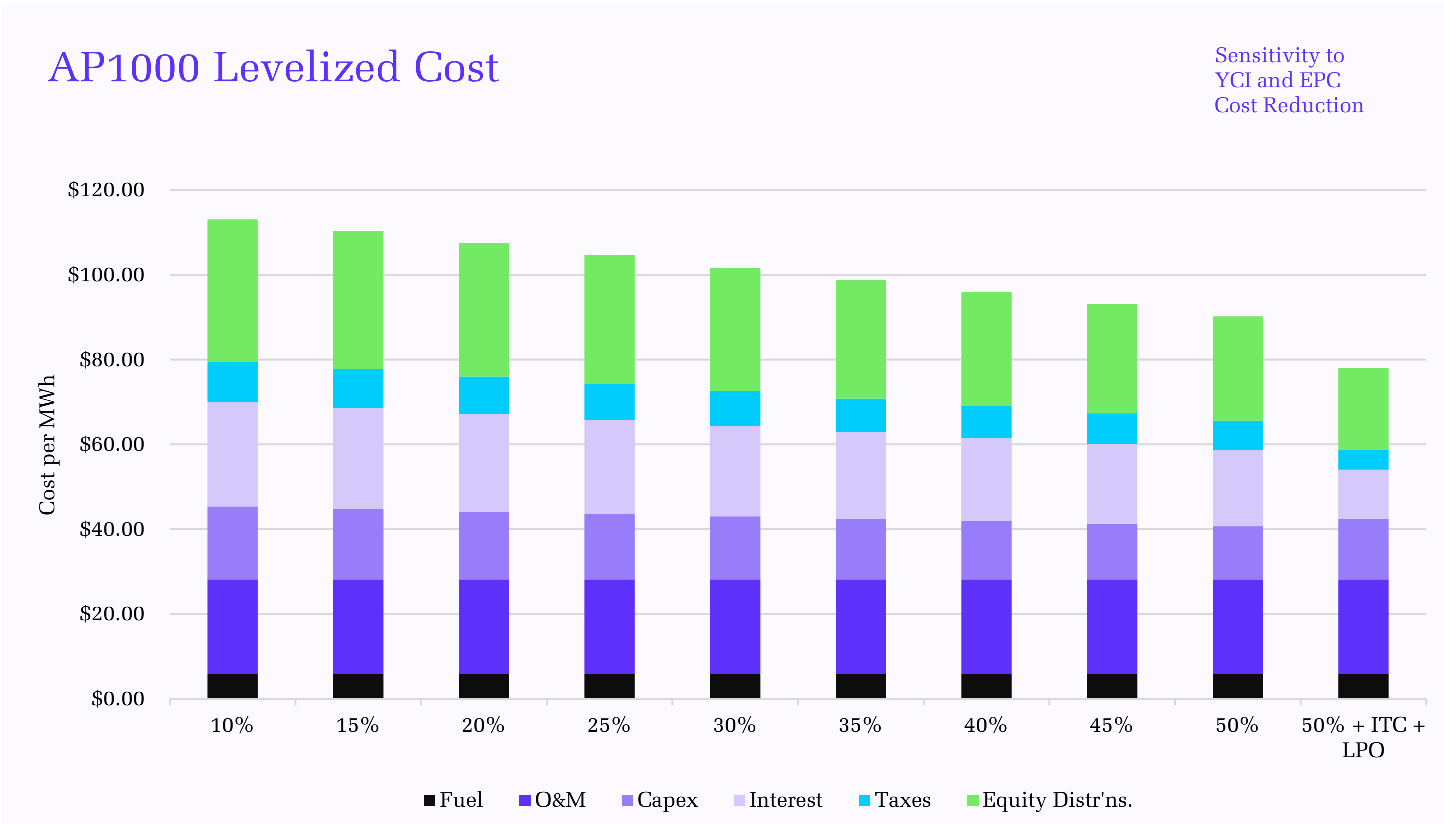

Figure 19 (JFI Modeling)

Fuel costs

JFI's supply-demand modeling points to a large gap between near-term production plans and future reactor requirements, which will need to be filled by capacity expansion and greenfield mining projects. Fracturing of global enrichment supply chains could also potentially mean more enrichment capacity is needed in North America and Europe, even after taking recently announced capacity expansion projects at Areva and Urenco's facilities in New Mexico and the Netherlands into account.

The nuclear fuel cycle comprises four steps:

- **Mining and milling:** extracting uranium ore (primarily UO_2) and turning it into "yellowcake" (U_3O_8). Major players include Kazatomprom (Kazakhstan) and Cameco (Canada).
- **Conversion:** turning U_3O_8 into UF_6, which at sea level is a gas above 57°C (important for enrichment). Key players include state-owned nuclear champions in Russia (Rosatom), China (CNNC) and France (Orano), as well as privately owned facilities in Canada (Cameco) and the US (a Honeywell / General Atomics JV).
- **Enrichment:** the energy-intensive process of using centrifuges (or, historically, gaseous diffusion) to increase the concentration of the U-235 isotope in UF_6 to the ~3-5% range required in most reactors. Nearly half of the world's enrichment capacity (measured in "separative work units" or SWUs) is in Russia, with roughly a third in Europe and about a tenth in each of the United States and China.
- **Fuel fabrication:** manufacturing the fuel rod assemblies that are loaded into reactors. Fabrication capacity is fairly widely distributed globally (fuel tends to be fabricated close to where it is consumed), with Westinghouse (now a Cameco subsidiary) and Framatome (controlled by the French state via EDF) the major suppliers to Western utilities.

Nuclear refueling is an involved process that involves taking a plant offline for 30 days or more in order to install a fuel rod assembly designed for a specific model of reactor. Because nuclear fuel is incredibly energy-dense, plants only need to be refueled every 12 to 18 months, but it's a huge undertaking that takes careful advanced planning.

Historically, uranium prices have been correlated with US and European utilities' inventory decisions ($R^2 = 0.4$). Lower prices are associated with inventory drawdowns, as in much of the 1990s and early 2010s. Conversely, higher prices and inventory accumulation have gone together, as during the late 2000s bull market.

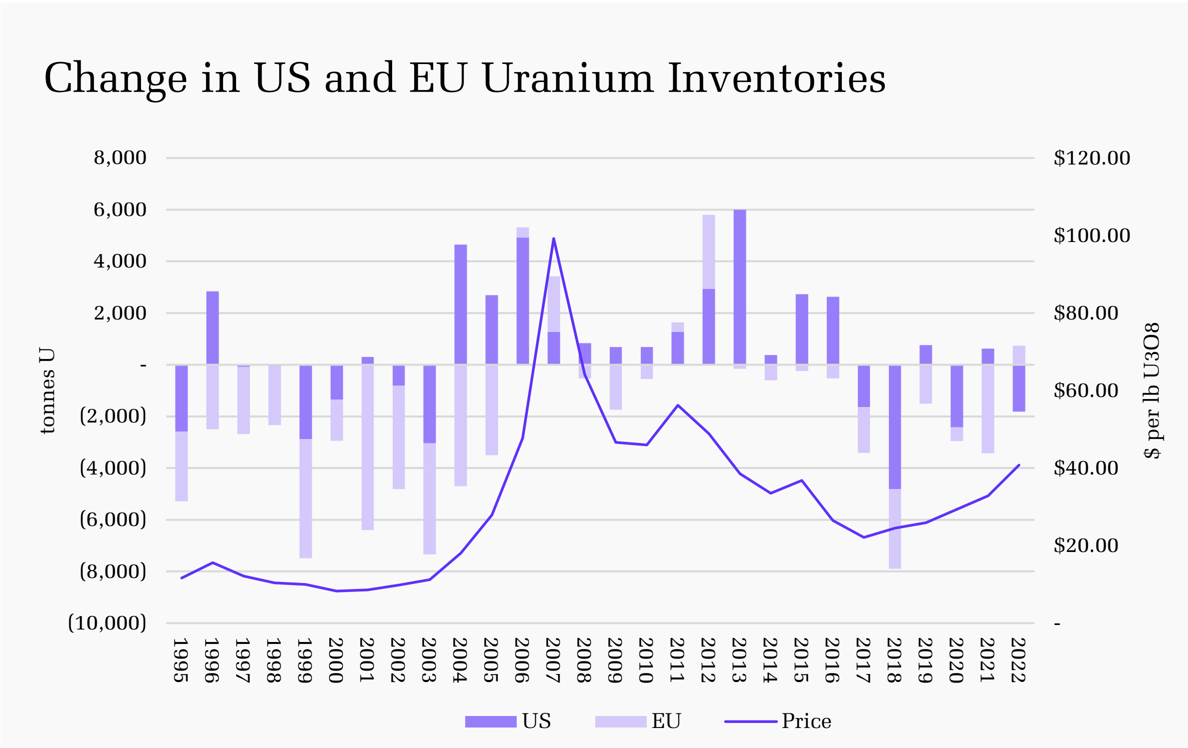

Figure 20 (EIA, Euratom, IMF)

Uranium mining and enrichment represent the majority of the value in the nuclear fuel cycle – about 73 percent of the overall cost of nuclear fuel, at recent prices. Entering 2024, spot prices for natural uranium prices breached $150 per kg of U, 63 percent higher than their average price of 2023, and 234 percent above the inflation-adjusted low of $45 per kg they reached in June 2017.

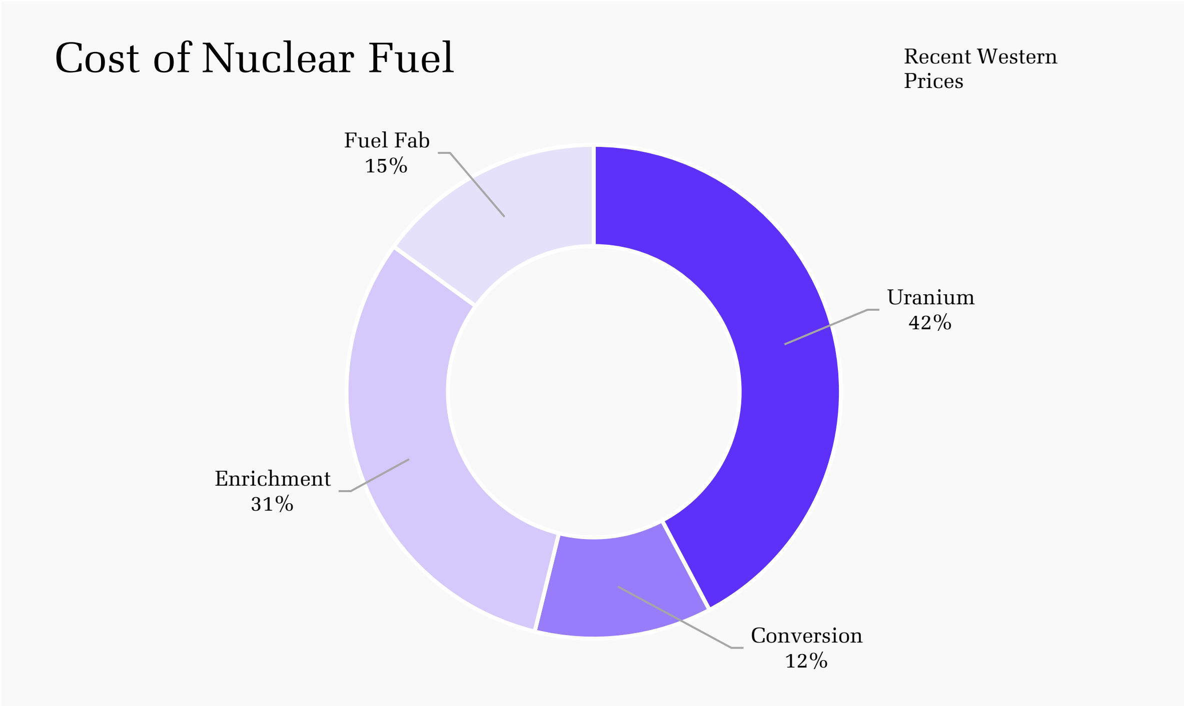

Figure 21 (IMF, Centrus, Cameco, Constellation Energy)

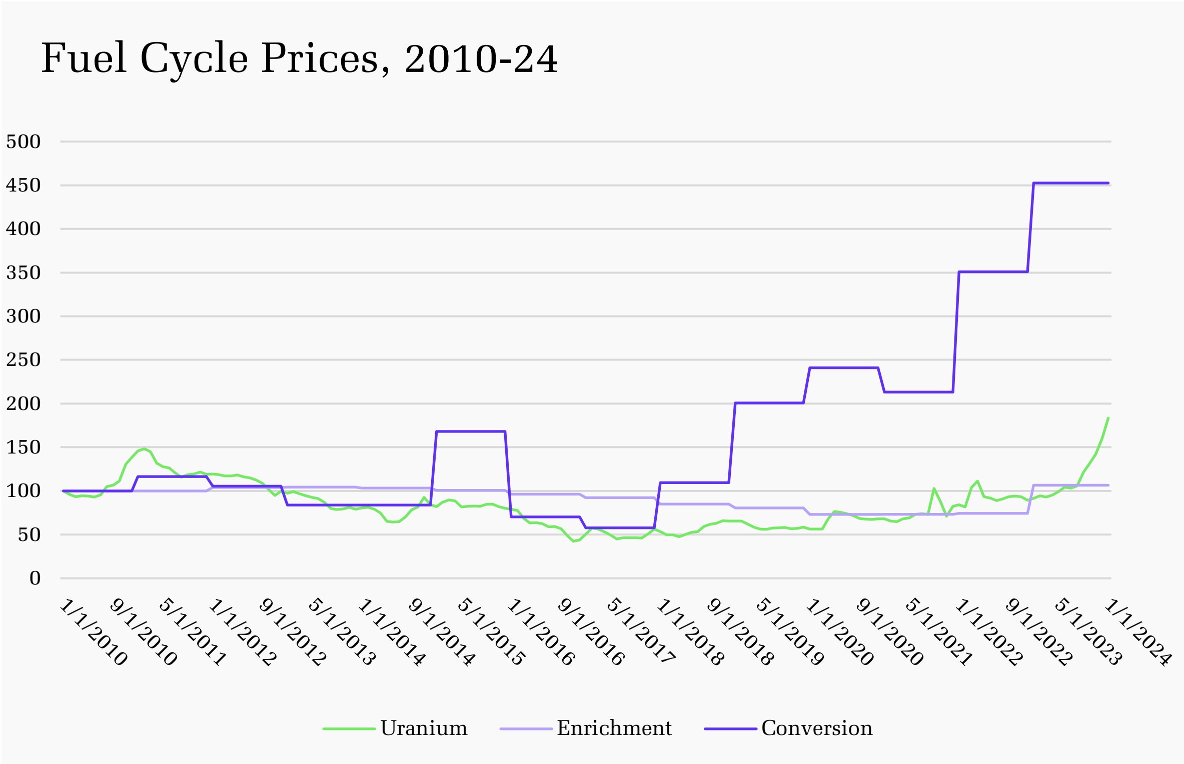

Figure 22 (IMF, Centrus, Cameco, Constellation Energy)

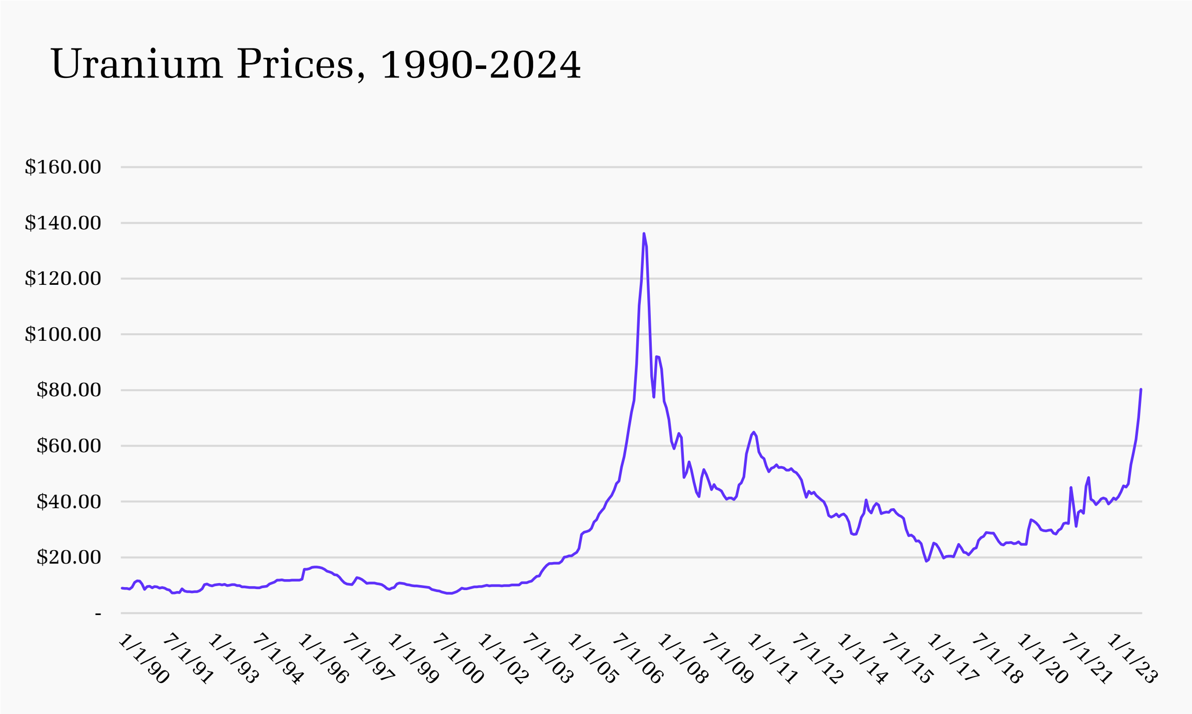

Figure 23 (IMF, Centrus, Cameco, EIA, FRED)

The economics of nuclear power make short-run demand extremely inelastic. In the US, fuel costs averaged just 20 to 25 percent of revenue for nuclear power plants in the period from 2010 to 2020, and even less in 2021 and 2022 in the wake of higher energy prices, which sent the market price of power higher in much of the world. On the other hand, **power plants operate much closer to breakeven when operating and maintenance costs are taken into account.**

Because market entry and exit in power markets is uniquely difficult – regulators tend to step in to keep firm power resources in the market, because backfilling the capacity provided by aging plants can mean at least two to three years of planning, permitting, and construction time – these short run dynamics can cause a substantial amount of economic pain for plant operators, while delaying demand destruction. Combined with a much more concentrated global supply chain (the two largest producers of uranium, Canada and Kazakhstan, supply nearly 60 percent of the world's output, for example), and the length of the refueling cycle, these dynamics mean the market can bear substantial price appreciation before self-correcting via supply response.

A changing demand story

Nuclear power generation has been stagnant since the last uranium bull market, in the late 2000s. Globally, nuclear energy only reached pre-

Fukushima levels in 2021. However, our modeling suggests that **nuclear generation is on the cusp of a multi-decade return to growth**, with nuclear power growing at an annual rate of **2.4 percent** from 2022 to 2030, after a (0.3) percent annual decline from 2020 to 2022.

In the last decade-plus, ~38 GW of nuclear capacity came offline in Europe and the Americas, and another ~17 GW of capacity was decommissioned in Asia outside of China (mostly in Japan). These plant shutdowns reduced global nuclear capacity by ~15 percent. Plants are expected to be shut down at a similar pace over the next decade, per BNEF, which is to be expected as the nuclear fleet continues to age in Russia and the West.

Counteracting this decline in Europe, the Americas, and Japan, nuclear construction has picked up massively in China, the Middle East, and Russia (which needs to backfill expected closures). Construction starts ranged from 6-8 GW per year in 2018-23, about 1.5-2.0x the rate of closures forecast by BNEF.

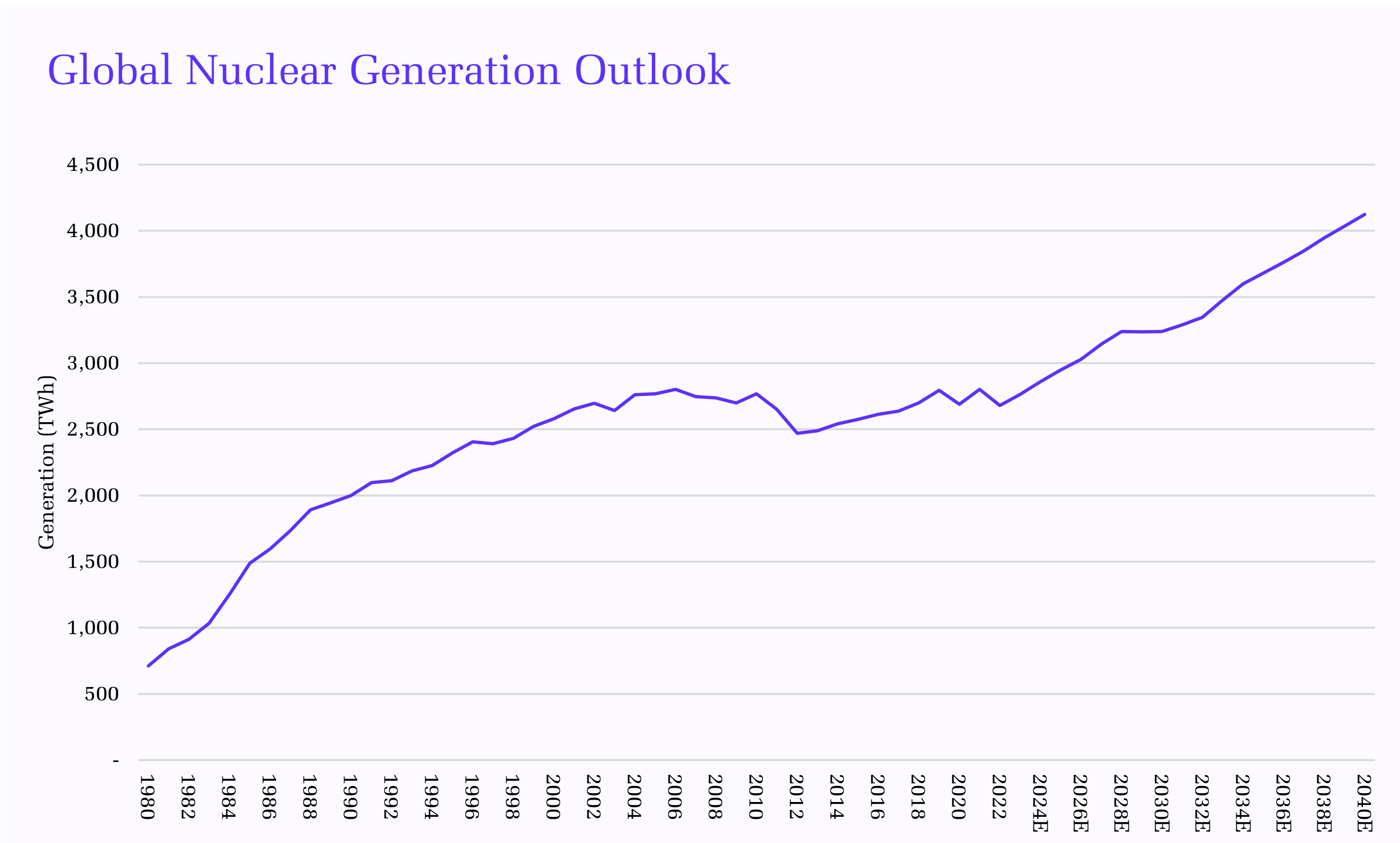

Figure 24 (JFI Modeling)

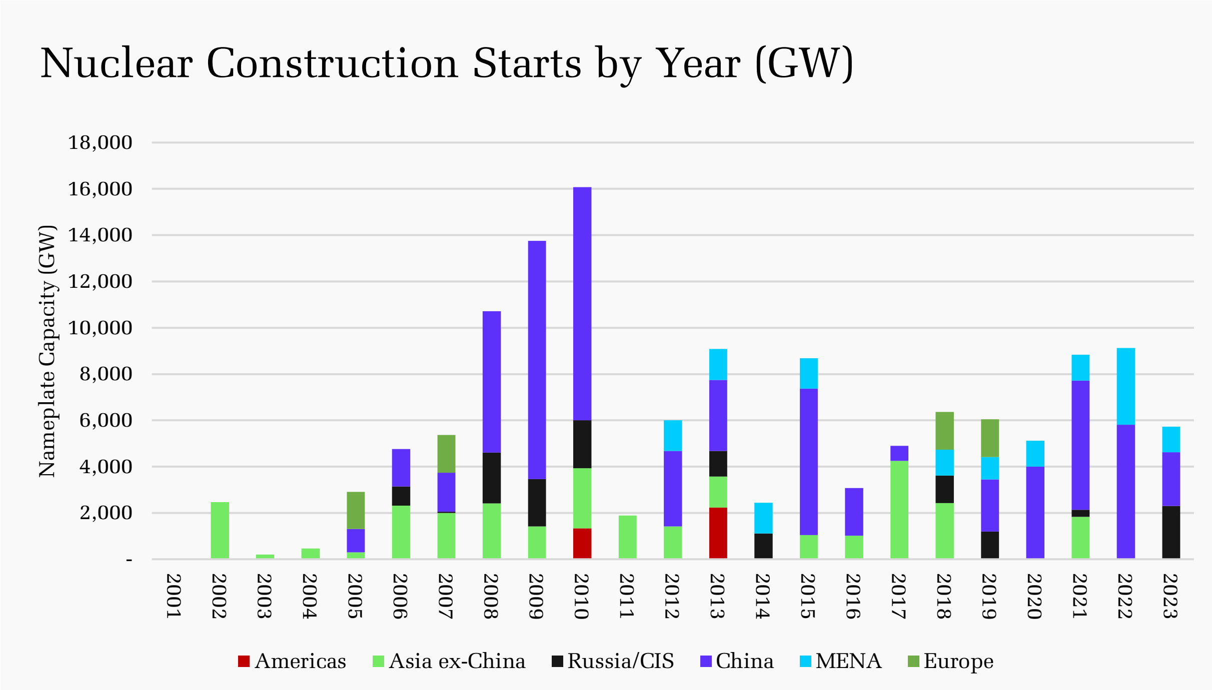

Figure 25 (IAEA)

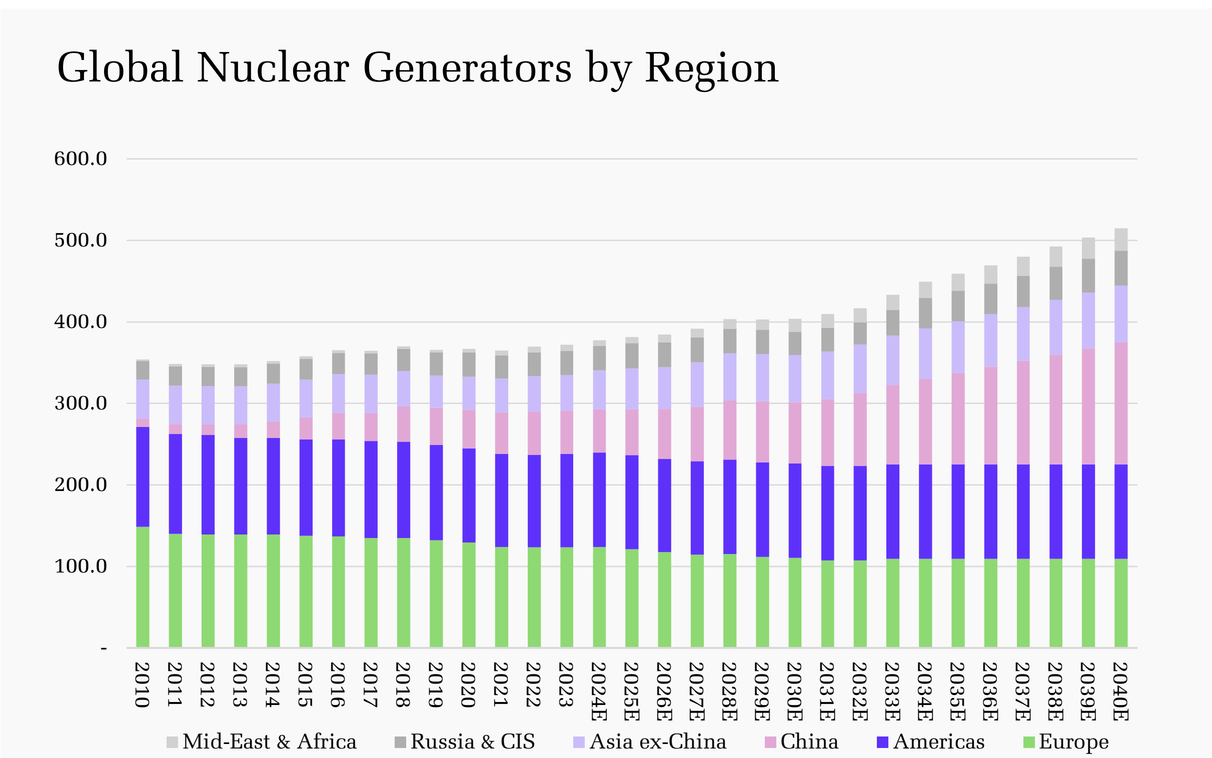

Figure 26 (IAEA)

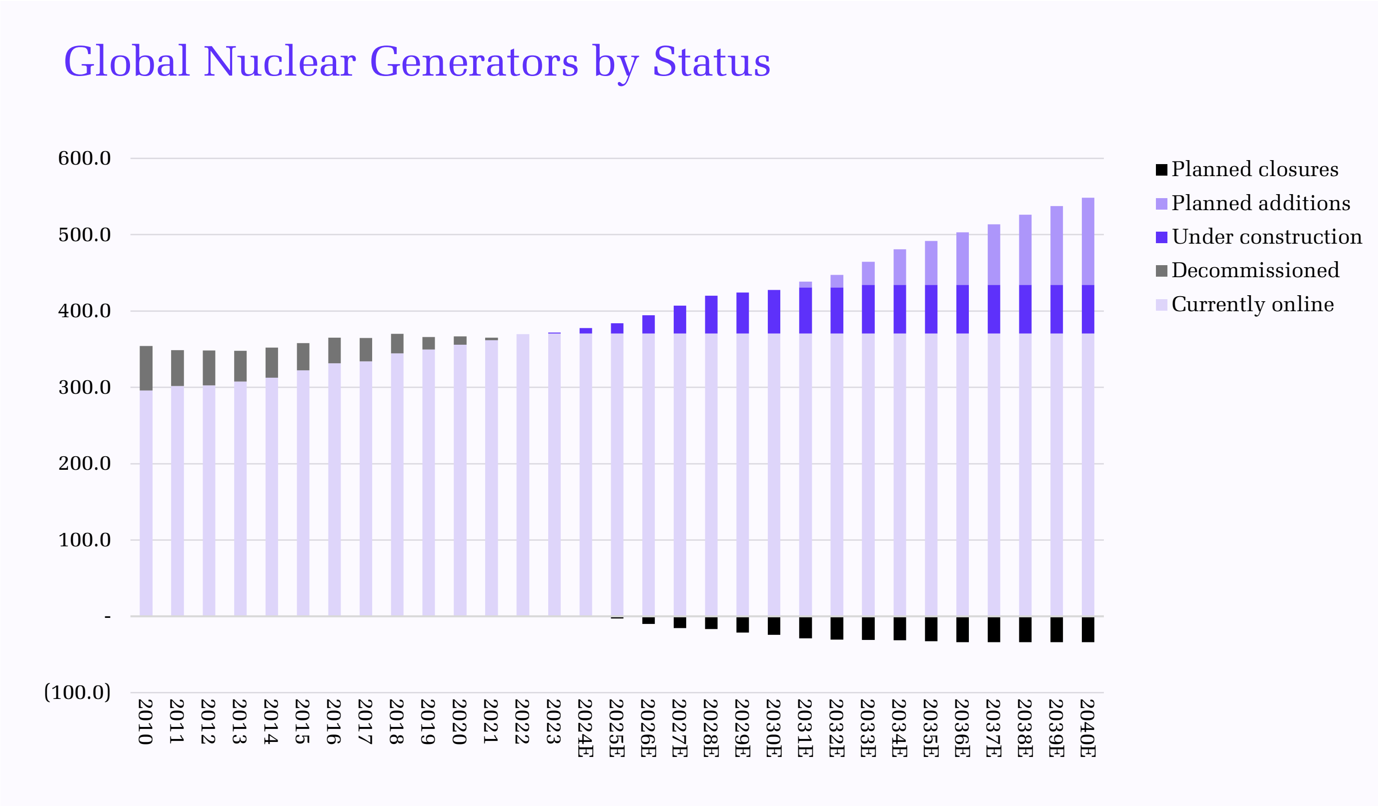

Figure 27 (JFI Modeling; IAEA)

JFI modeling points to **growing power plant demand for uranium, with natural uranium and enrichment requirements growing at a roughly 3 percent annual rate between 2022 and 2030, and 2.5 percent thereafter.** There is upside risk to these growth rates if the world increasingly shifts to higher levels of enrichment, which potentially allow for higher burn rates and longer refueling cycles.

There is also upside risk to our estimates if the world gets anywhere close to the COP28 nuclear declaration's goal to triple nuclear power capacity. Our modeling contemplates 404 GW in global generation capacity by 2030 and 515 GW by 2040, totals that are 16 percent and 8 percent below the IEA's base-case, Stated Policies Scenario, because, in the interest of conservatism, we include only a modest pace of construction starts, based on publicly announced plans and the recent pace of construction.

Power Plant Demand for Uranium

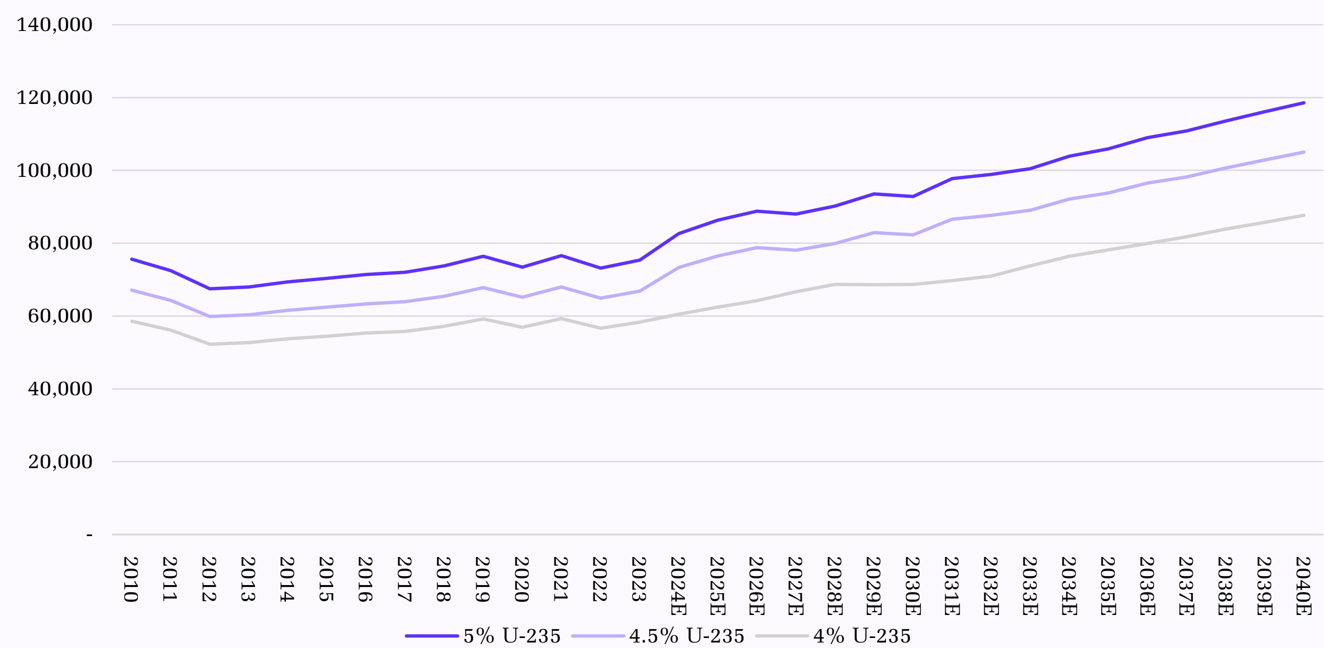

Figure 28 (JFI Modeling; IAEA)

Annualized Growth in Uranium Needs by Region

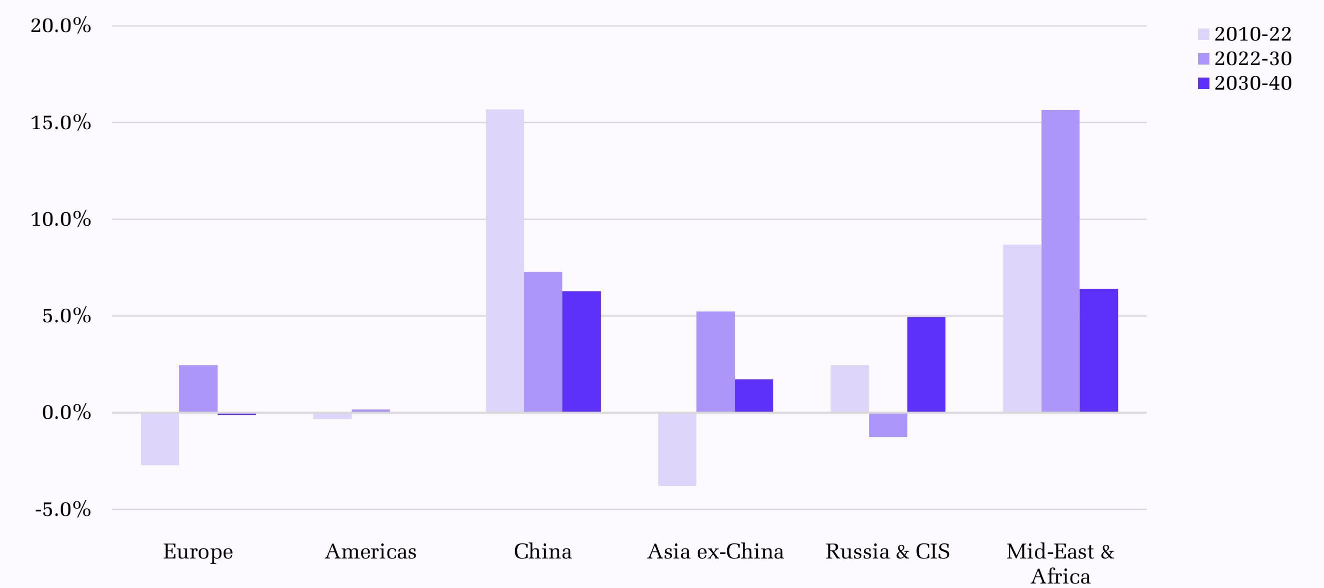

Figure 29 (JFI Modeling; IAEA)

We do not have a crystal ball into the future of uranium supplies. But we note that, across our scenarios, **between 21 and 48 million tonnes of additional uranium production will be needed globally by 2040E.**

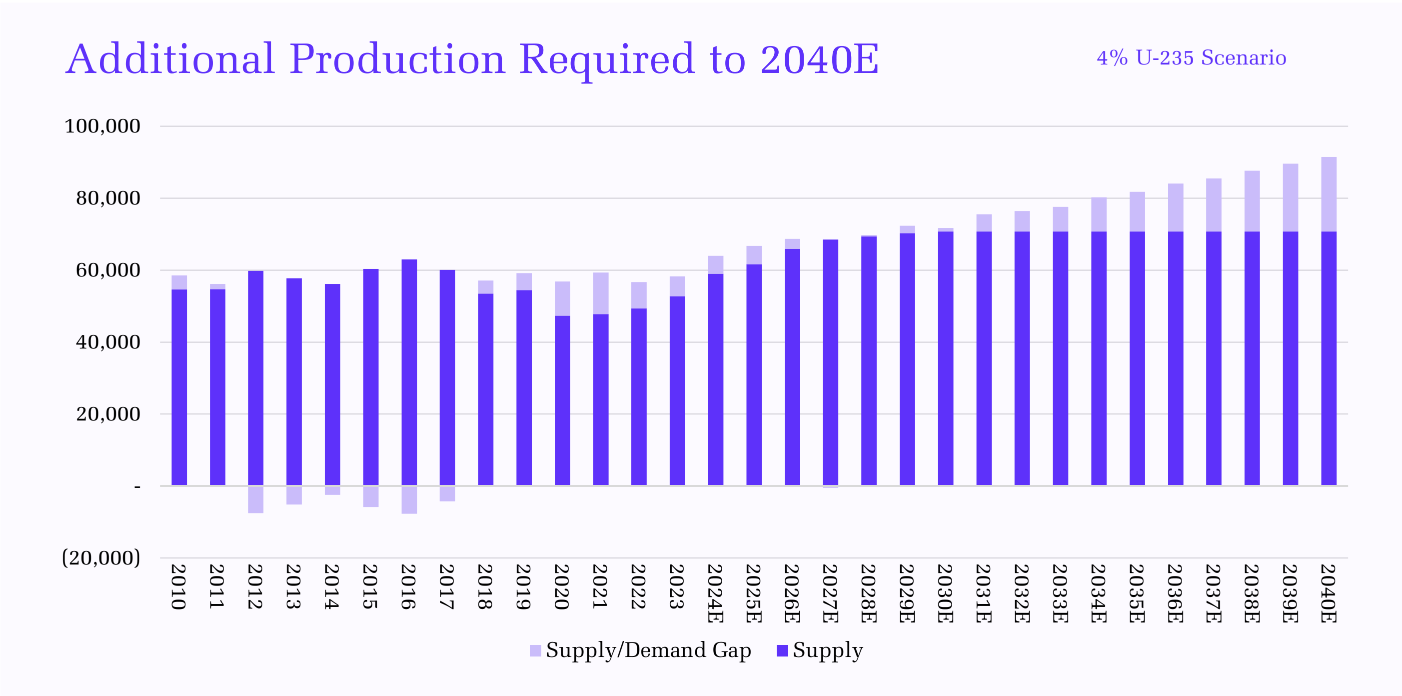

Figure 30 (JFI Modeling)

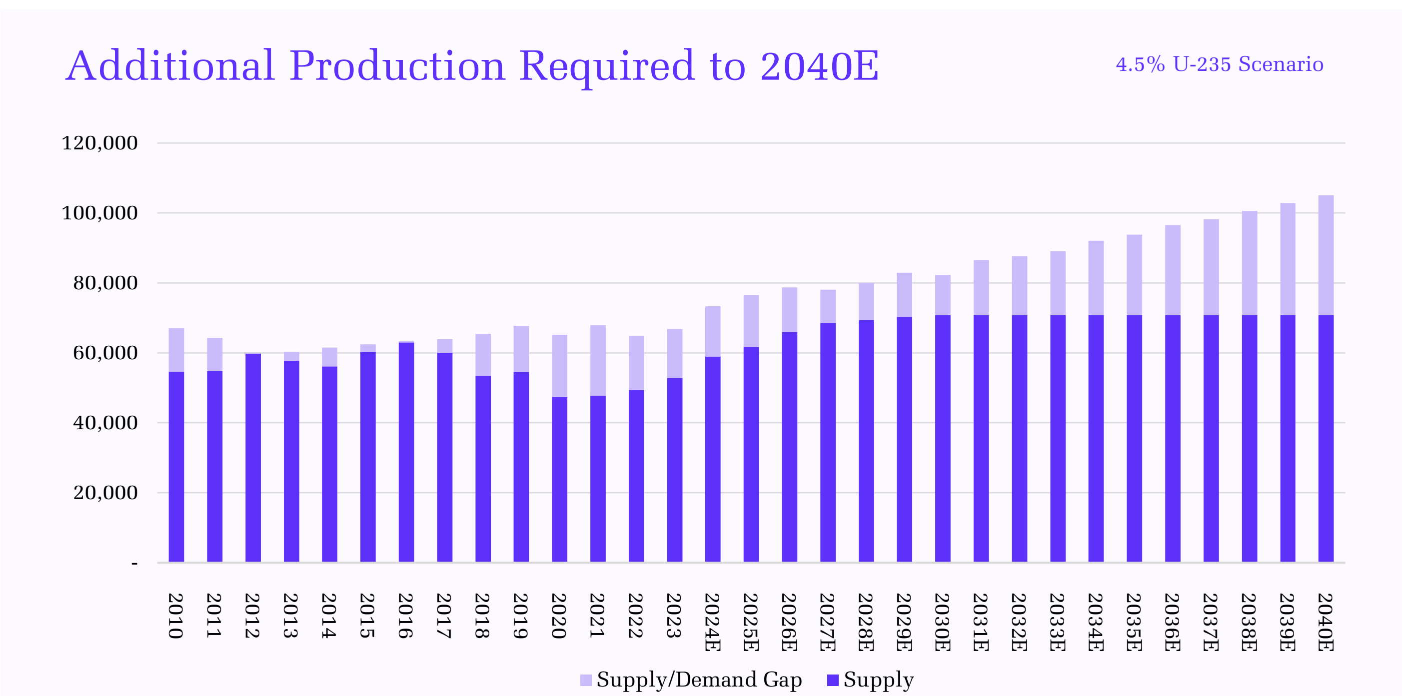

Figure 31 (JFI Modeling)

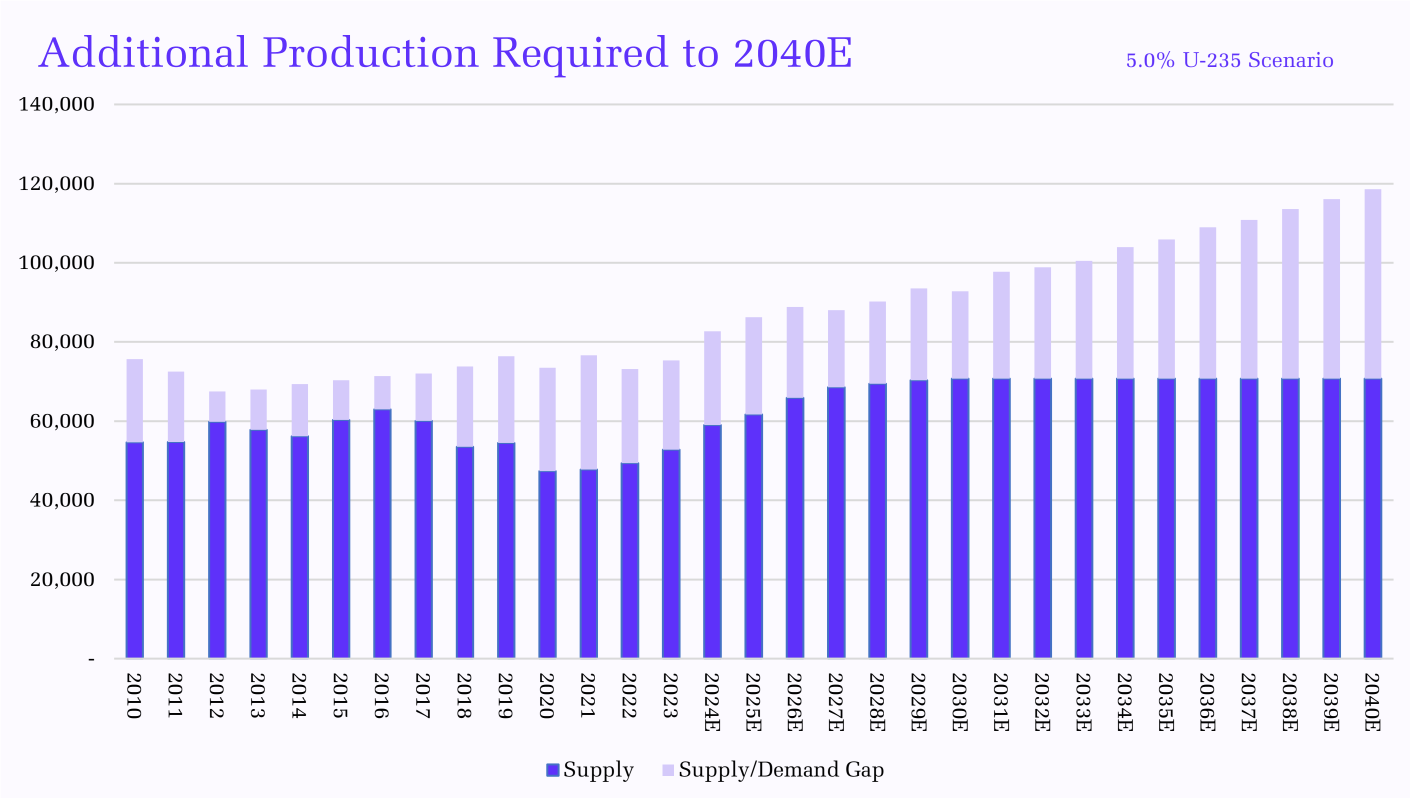

Figure 32 (JFI Modeling)

Global supply and energy security

The geography of global uranium and fuel services adds another layer of complexity. Globally, Russia and its neighboring states in Central Asia (particularly Uzbekistan and Kazakhstan) are net exporters of both uranium and, in Russia's case, enrichment. Collectively, Europe and the United States depended on Russia and other states that pose geopolitical risks (Uzbekistan, Kazakhstan, and Niger) for **approximately 55 percent of uranium supplies in recent years.**

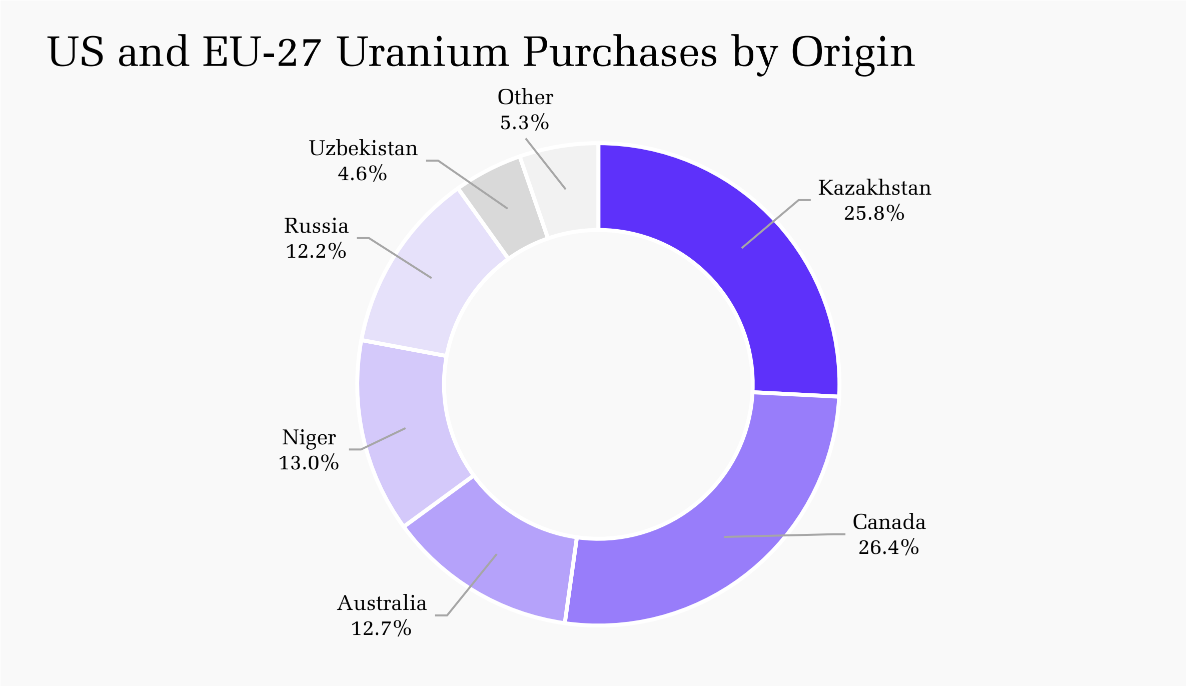

Figure 33 (JFI Estimates based on EIA, Euratom)

Essentially all Canadian and Australian uranium production goes to customers in the United States and Europe already. If uranium supplies from these regions were disrupted, either because of conflict and supply chain woes or because of policy changes on either side, it would imply a “call” on Canadian, Australian, and other suppliers of over 12,000 tonnes of uranium per year, i.e. almost as much as the **entire current production** of Canada and Australia.

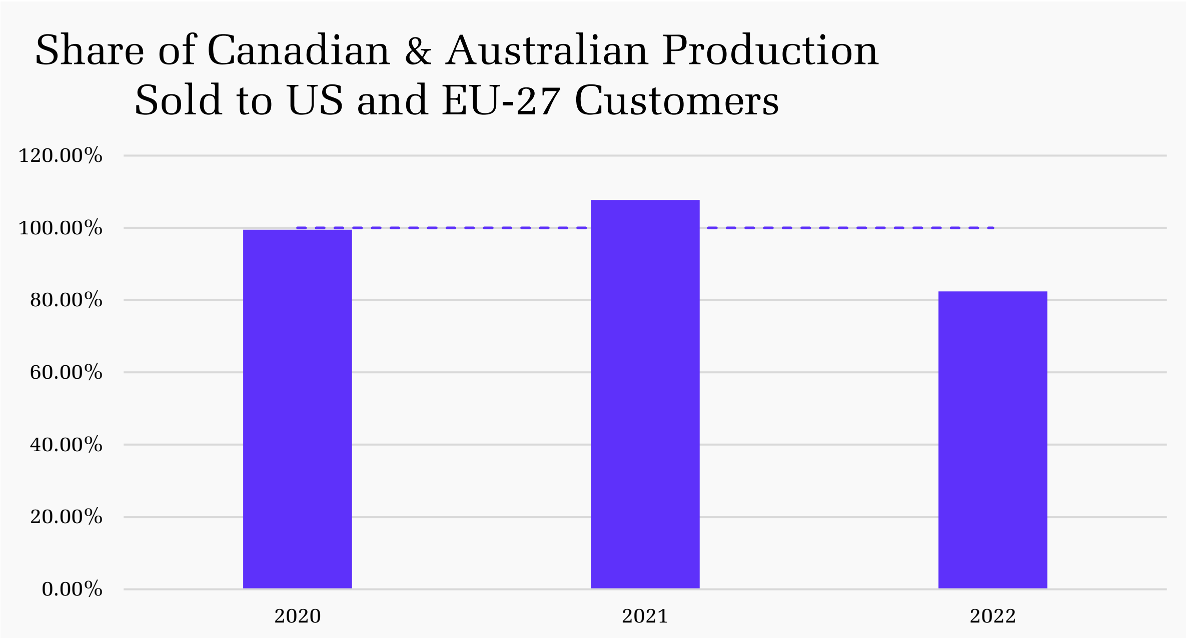

Figure 34 (EIA, Euratom)

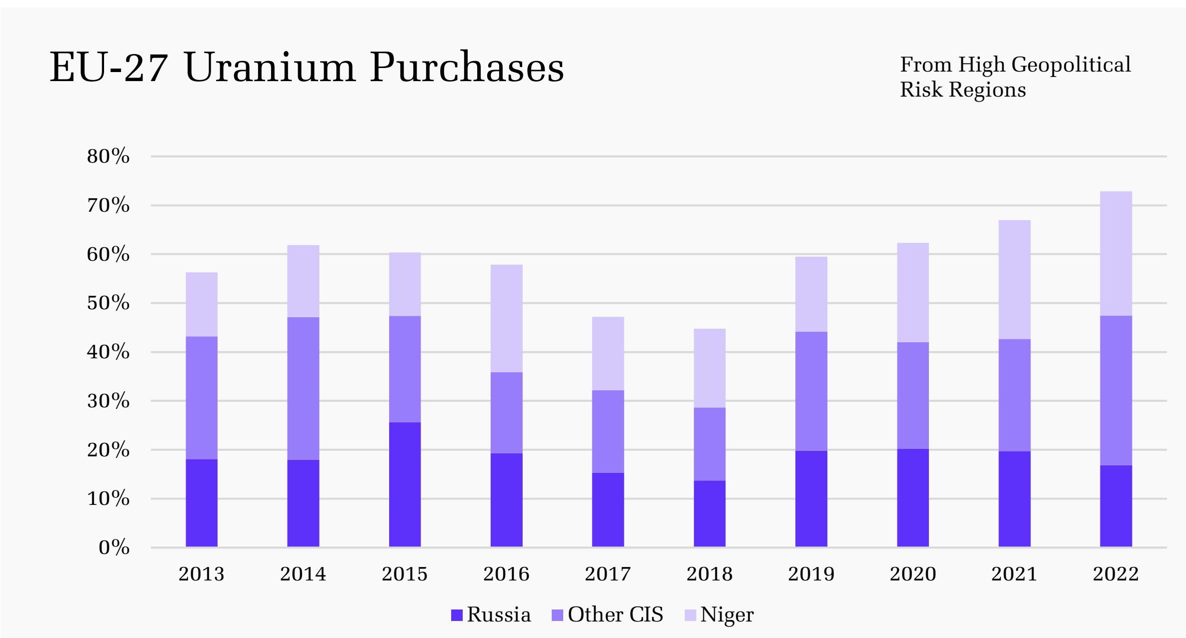

Figure 35 (EIA, Euratom)

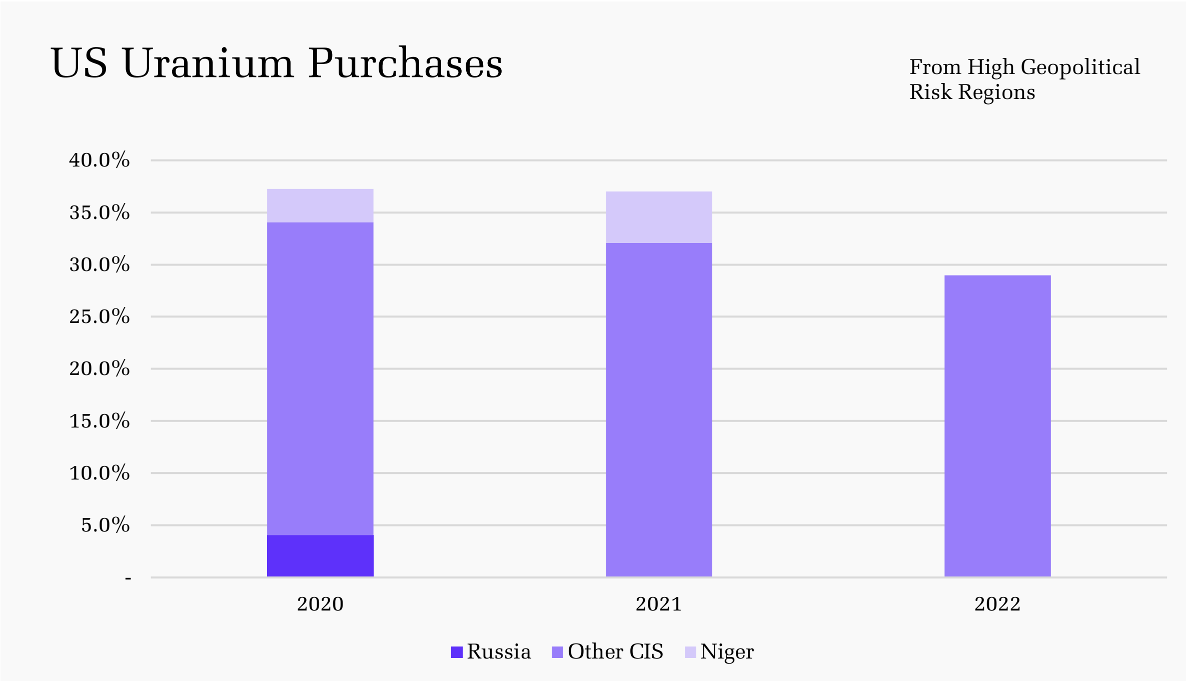

Figure 36 (EIA, Euratom)

Supplies of enrichment services are even more concentrated in Russia, notable because a bill is making its way through the US Capitol that would ban uranium imports from Russia without a DOE waiver through 2028, and completely thereafter. Based on data disclosed by the US EIA and the Euratom Supply Agency on procurement of enrichment services by nuclear utilities, we estimate that Russia is home to over 70 percent of the world's spare enrichment capacity.

Enrichment Capacity by Country

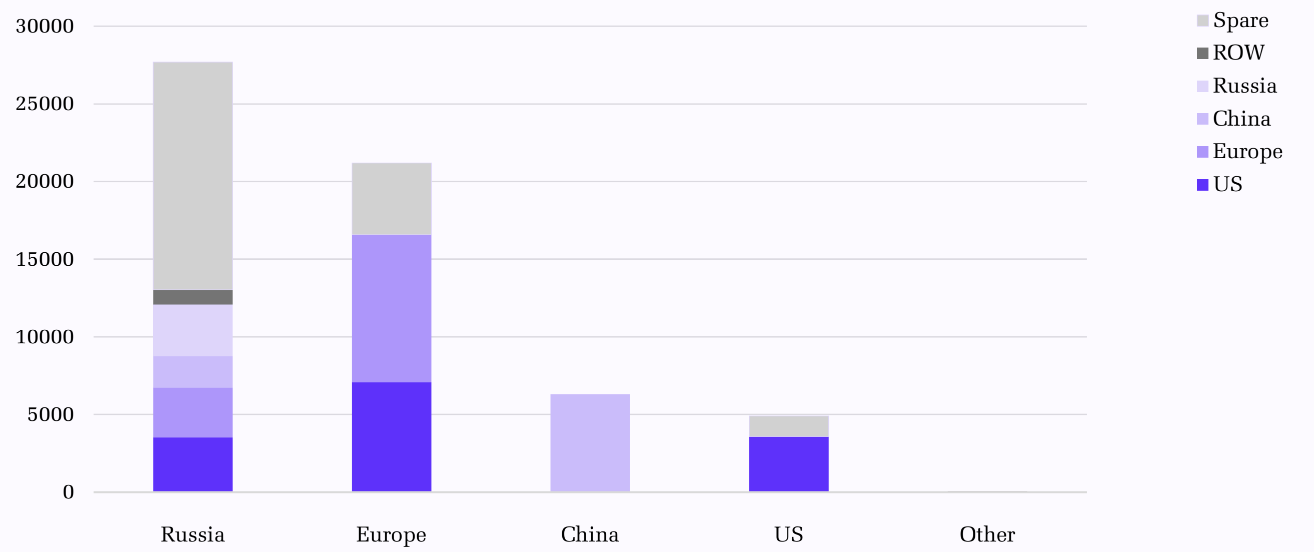

Figure 37 (JFI estimates based on EIA, Euratom, WNA)

Ultimately, the key policy and markets questions around the nuclear fuel cycle revolve around **how to turn the price signals coming from the markets for uranium, conversion, and enrichment services into a durable supply response.** With several junior mining projects coming online in 2023 and 2024E in Australia, Namibia, and the United States, announced capacity expansions that will add 2.95 million separative work units (SWUs) of Western enrichment capacity, and plans to ramp up production from the two largest miners, Kazatomprom and Cameco, things are moving in the right direction.

However, much uncertainty remains. Announced capacity expansions across the fuel cycle might be enough to moderate security-of-supply concerns if growth in nuclear generation remains modest, as the IEA, S&P, and many others predict. **But the supply response would need to be much more dramatic to ensure affordability and security of supply in a full-throated American and European nuclear renaissance.** Clear domestic sourcing criteria, whether voluntary or policy-driven, and even **investment tax credits for the front end** of the nuclear fuel cycle, modeled on Canada's 30 percent ITC for critical mineral exploration, are policy instruments worth exploring.

Financing costs

The lifetime cost of nuclear power is highly sensitive to the cost of financing – ultimately a function of interest rates, equity hurdle rates, and the mix of debt and equity used to fund a project. Cheaper financing – perhaps provided by the DOE's LPO program and its analogues overseas – could drive the effective cost of nuclear power much lower. But catalyzing private capital to join in will also require dealing with the risks inherent in a long-term infrastructure investment – putting guardrails around construction costs and revenue realization.

Nuclear power is a complex technology with high upfront costs and long deployment timelines. This disproportionately exposes deployment of the technology to prevailing financing conditions. As shown below, even traditional light-water reactor nuclear displays high sensitivities to the cost of capital compared to other generating technologies.

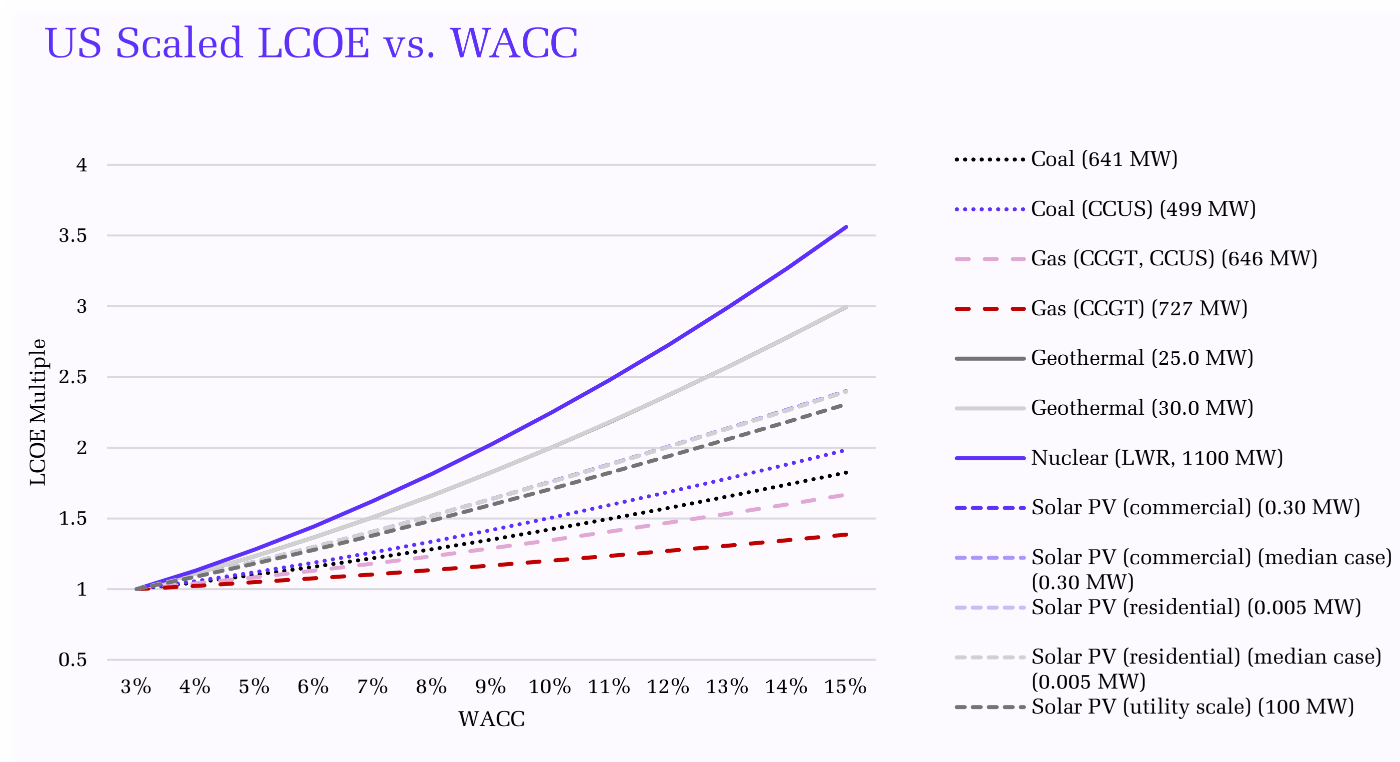

Figure 38 (NEA LCOE Calculator; LWR - Light-water Reactor, CCGT - Combined-cycle Gas Turbine, CCUS - Carbon Capture, Utilization, and Storage)

In JFI's default levelized cost analysis for nuclear, we assume a 5.4 percent cost of debt, 60 percent debt-to-total-capital ratio, and 12 percent equity hurdle rate. Our baseline case shows that 51% of levelized costs can be attributed to equity and interest payments. A 3.2 percentage point decline in the weighted average cost of capital (WACC), from 8.6 percent to 5.4 percent produces a **27 percent decline in the lifetime cost** of the plant's power, and 40% of levelized costs attributable to equity and interest payments. Said another way, each **0.4 percentage point decrease in WACC produces a roughly 4 percentage point decrease in the total cost of power.**

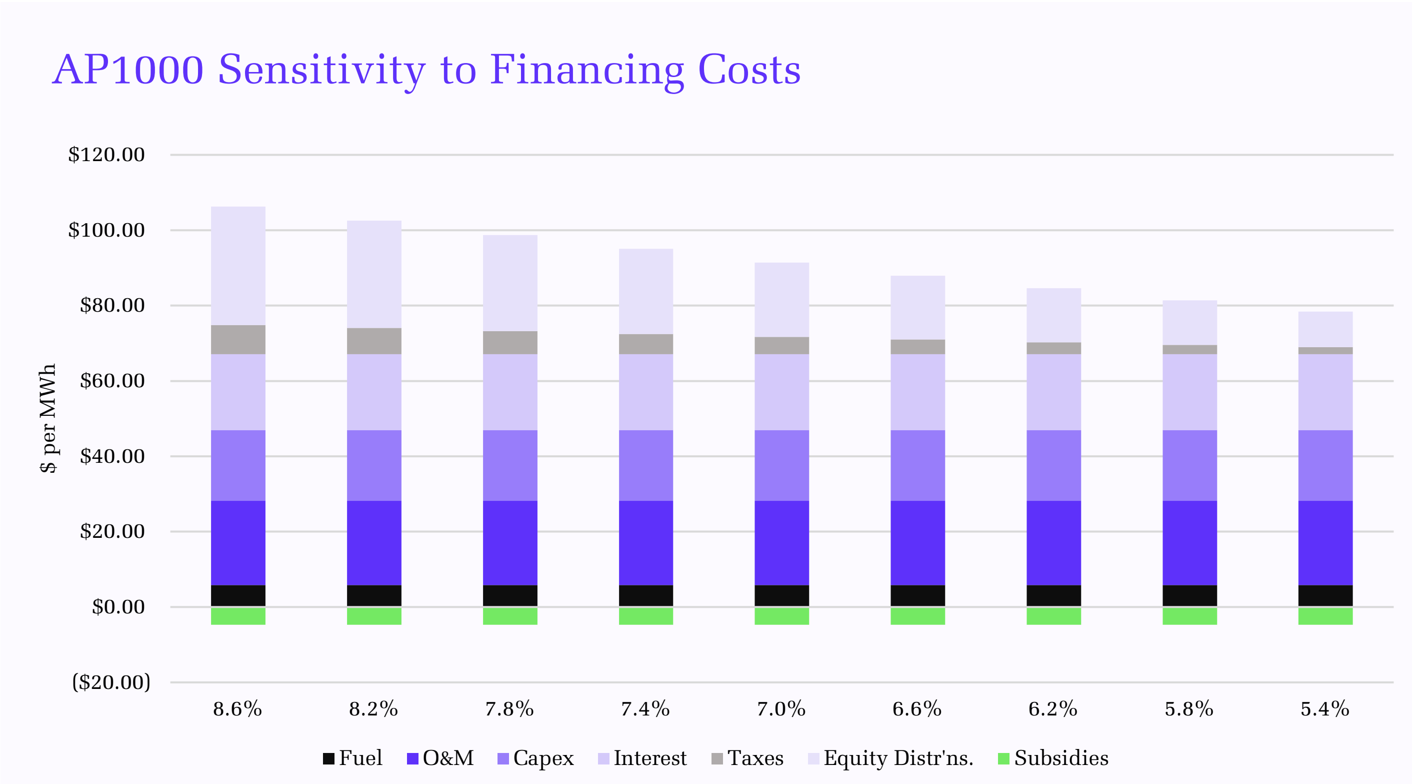

Figure 39 (JFI Modeling)

Market environment

Structural factors have also reduced the profitability and implicitly increased the cost of capital for nuclear power plants in the US. In restructured electricity markets, generators bid into wholesale power markets at marginal cost, which, in an era of an increasing renewable share with zero marginal cost and low natural gas prices, has made it hard for plants to recoup fixed costs and led many plants to shut down early.

Mechanisms such as the Civilian Nuclear Credit program in the Infrastructure Investment and Jobs Act (IIJA), zero-emission credits enacted in several states, and tax credits for existing reactors through the IRA[7] have slowed this trend but essential challenges to new-build nuclear power economics remain. Indeed, these "uneconomic" plant closures have slowed progress in various states towards meeting critical net zero goals, prompting financial support from the DOE LPO to put some of these plants back into operation.

Table 1. U.S. Nuclear Reactor Shutdowns: 2013-2021

Organized by Shutdown Date

Reactor	State (Cong. District)	Shutdown Date	Generating Capacity (Megawatts)	Start-Up Year	Major Factor(s) Contributing to Shutdown
Crystal River 3	Florida (FL-11)	Feb. 2013	860	1977	Cost of major repairs to reactor containment
Kewaunee	Wisconsin (WI-8)	May 2013	566	1974	Operating losses
San Onofre 2	California (CA-49)	June 2013	1,070	1983	Cost of replacing defective steam generators
San Onofre 3	California (CA-49)	June 2013	1,080	1984	Cost of replacing defective steam generators
Vermont Yankee	Vermont (VT-at large)	Dec. 2014	620	1972	Operating losses
Fort Calhoun	Nebraska (NE-1)	Oct. 2016	479	1973	Operating losses
Oyster Creek	New Jersey (NJ-3)	Sept. 2018	614	1969	Agreement with state to avoid building cooling towers
Pilgrim	Massachusetts (MA-9)	May 2019	685	1972	Operating losses; rising capital expenditures
Three Mile Island 1	Pennsylvania (PA-10)	Oct. 2019	803	1974	Operating losses
Indian Point 2	New York (NY-17)	April 2020	1,020	1974	Low electricity prices; settlement with state
Duane Arnold	Iowa (IA-1)	Aug. 2020	601	1975	Lower-cost alternative power purchases
Indian Point 3	New York (NY-17)	April 2021	1,038	1976	Low electricity prices; settlement with state
		Total	**9,436**		

Source: CRS, with information from the U.S. Energy Information Administration and plant operator announcements.

Notes: Generating capacity numbers reflect "Net Summer" capacity.

Figure 40 (CRS)

[7] Constellation Energy, the largest US nuclear fleet operator, has seen its share price rocket thanks to revenue certainty provided by the § 45U PTC. Even then, the company's strategy appears focused on the existing fleet rather than new build, as relayed by S&P after Constellation's spinout from Exelon: "Constellation executives said in a call with Guggenheim analysts after the investor presentation that if no attractive nuclear asset deals are available, the company will return available capital to shareholders."

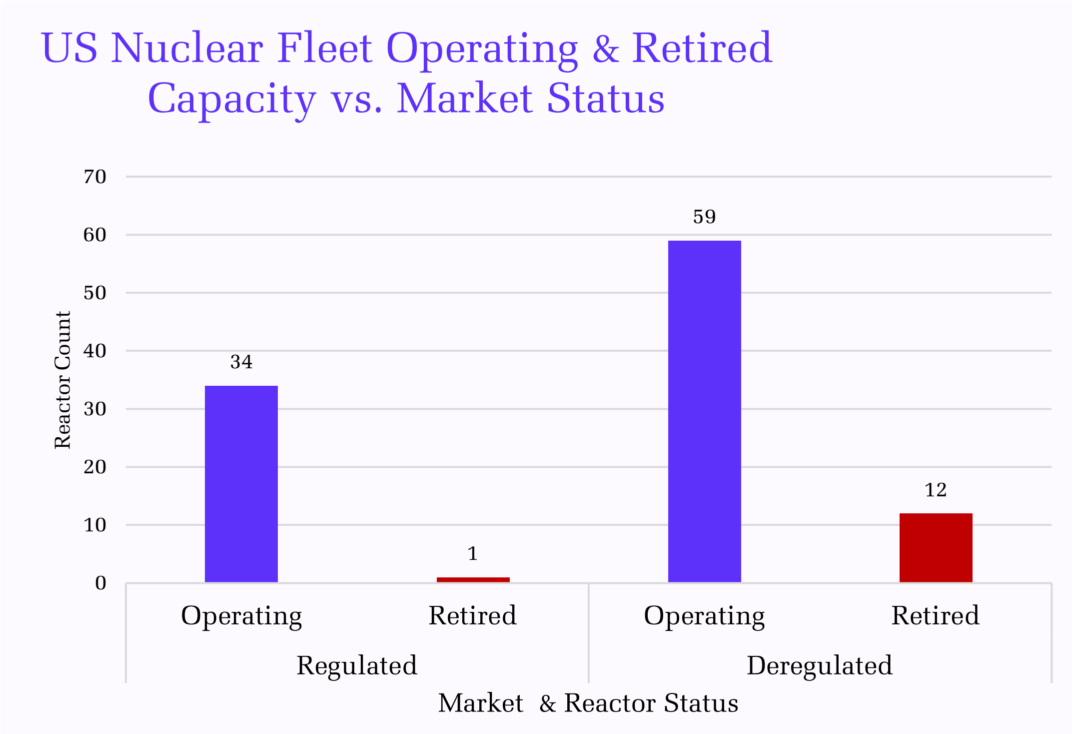

Figure 41 (EIA)

These dynamics point to an acute need for improved support in liberalized markets, alongside existing mechanisms such as loan guarantees, contracts for differences, and power purchase agreements to expand nuclear capacity

In the deregulated UK, the use of the regulatory asset base (RAB) model for new nuclear has been proposed in order to lower perceived project risk and financing costs by passing on some costs to consumers. In regulated markets, utilities are able to partially recover investment costs through adjustments to the rate base, which reduces project risk and improves bankability. Of course, rate hikes can be contentious, especially when consumers are on the hook for projects perceived to be mismanaged and costly. A key question is how these differences in power markets meaningfully influence plant economics and the likelihood of new build financing coming together.

The US, with its state-by-state variation between regulated and deregulated markets, provides a natural experiment in market structure, and the disparate fates of nuclear in regulated and deregulated states may point the way forward for reviving nuclear deployment: intrepid regulated utilities with strong balance sheets investing in first-to-nth-of-a-kind (FOAK, NOAK) projects until the technology's risk profile is amenable to investors deploying in deregulated markets. More generally, these trends merit a **broader reconsideration of market designs and structures compatible with supporting capital-intensive critical energy transition technology investments**.

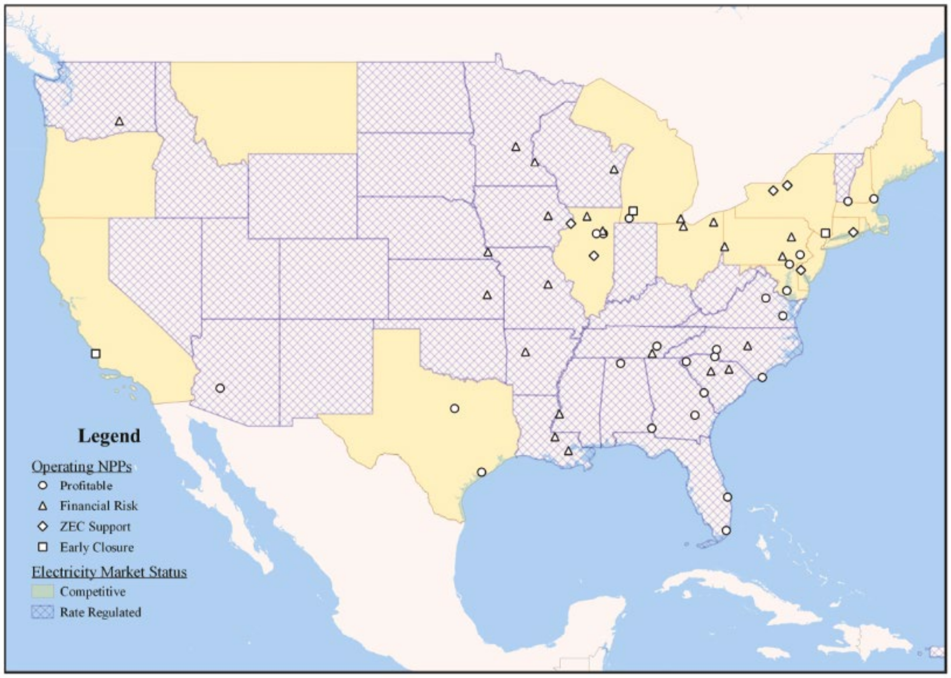

Figure 42 ([Lordan-Perret et al.])

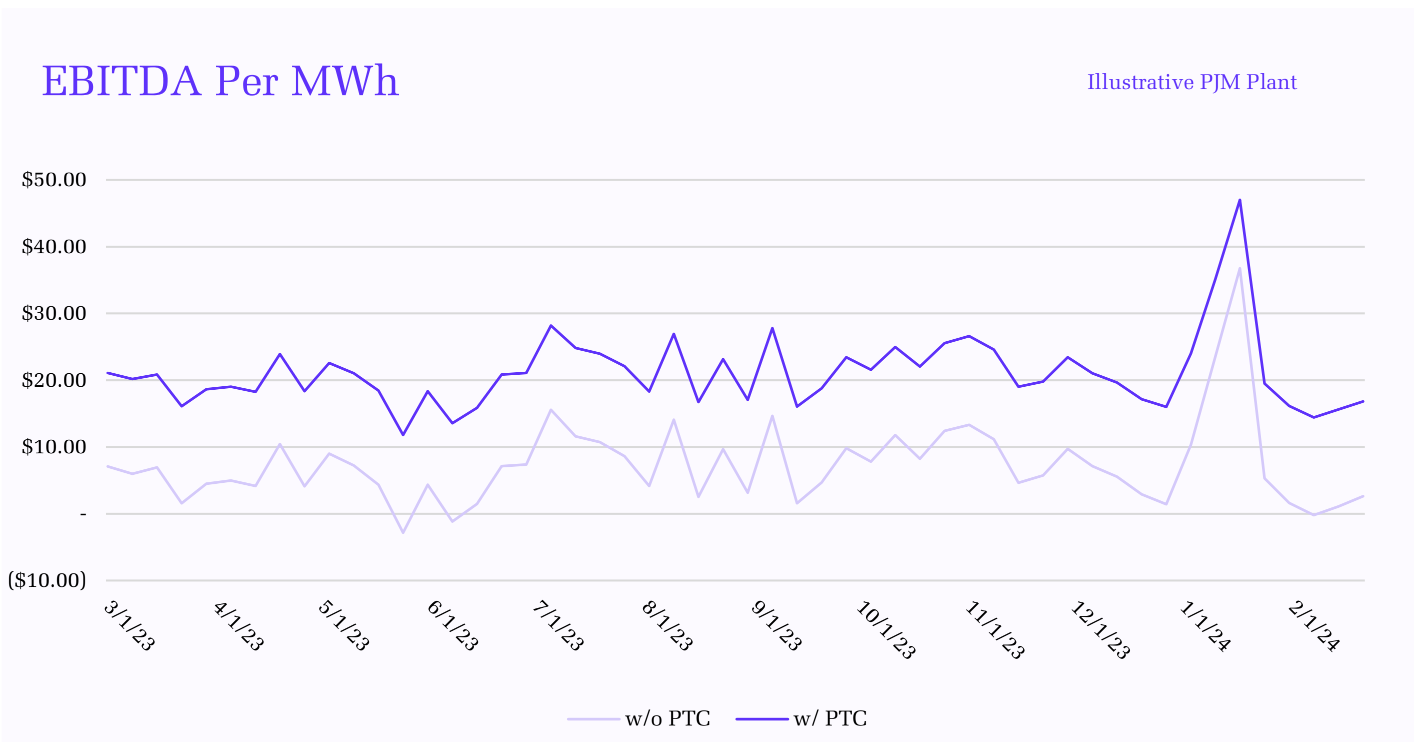

Figure 43 (JFI Modeling)

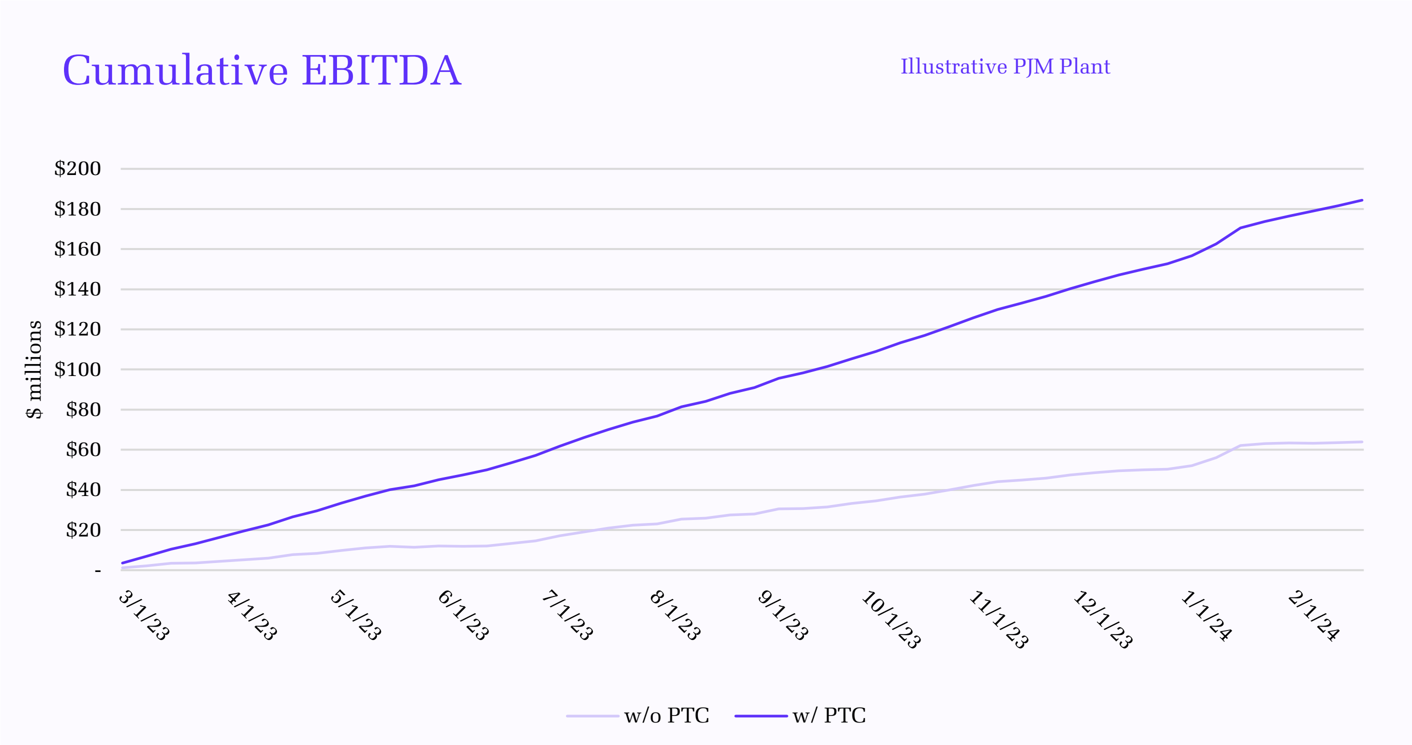

Figure 44 (JFI Modeling)

Outside the US and UK, large state-backed energy companies like EDF, KEPCO, Rosatom, CGN, CNNC have been able to leverage their sovereign backing, execution expertise, support from export-import banks, and strong balance sheets to offer generous financing terms and consistently deploy nuclear power. American & UK vendors tend to be much smaller and thus unable to offer the same financing. There have also been proposals for new **multilateral financial institutions** such as the International Bank for Nuclear Infrastructure to accelerate and harmonize global deployment, but these efforts remain in the concept phase. More encouragingly, despite past exclusion of nuclear from green financing frameworks, there has been increased appetite for **nuclear green bonds**, with recent offerings from the Canadian province of Ontario, EDF, and Constellation Energy[8].

[8] Constellation released a new green financing framework February of this year.

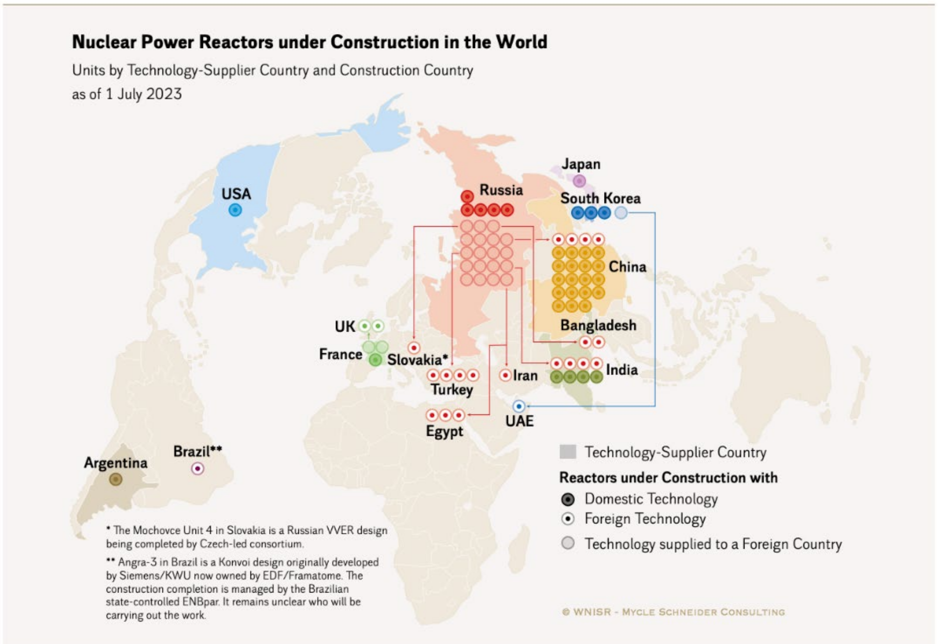

Figure 45 ([WNISR 2023](#))

A recent successful example of state-backed deployment is the UAE Barakah plant, consisting of four APR-1400 reactors, financed by a mix of banks and government entities.

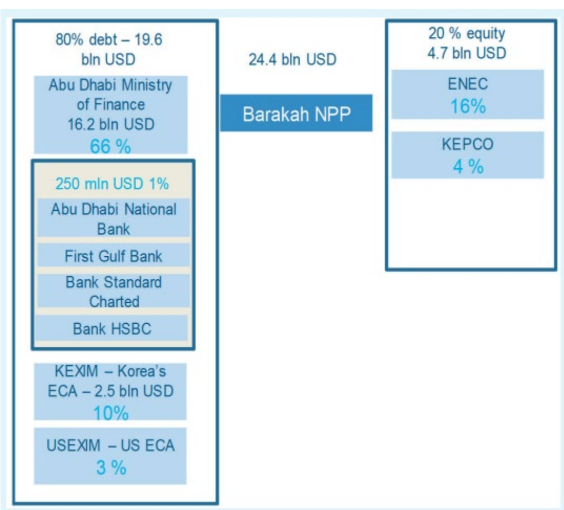

Figure 46 (Barakah plant financing structure, [IAEA](#))

Another model worth mentioning is the Finnish [mankala](#) cooperative approach that nuclear power company TVO used to build the Olkiluoto-3 reactor. Notably, this method has been applied to generate close to [40 percent](#) of all electricity and [67 percent](#) of all nuclear power in Finland. This model pools capital from power users to finance energy production that they can then use at cost. Famously, Areva and Siemens agreed to a fixed price [turnkey](#)

contract for the Olkiluoto-3 reactor, which led to Areva's bankruptcy and a restructuring at Siemens after cost overruns and delays. While the contractual terms limited TVO's exposure to these risks, protracted lawsuits ensued to settle conflicting claims related to these costs, underscoring the need for thoughtful allocation and structuring of project risk. Taking notes from the Finns, the French developed the industrial cooperative Exeltium in 2006 to stabilize long-term price support for the generation of EDF's nuclear fleet.

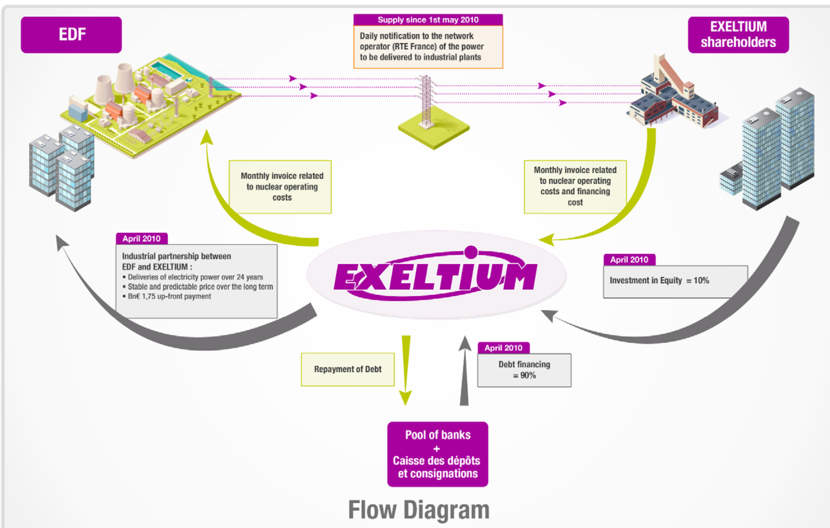

Figure 47 (EDF & Exeltium offtake structure)

In the United States, the **high investment costs of a nuclear plant relative to utility balance sheets** (for example, Vogtle 3 & 4 are now running at $35B+ in costs, and Georgia Power's 45.7 percent stake represents a significant outlay despite its $134B in assets) has led to a focus on developing small modular reactors (SMRs) and proposals of cost stabilization facilities and utility consortia to manage risk and attract sufficient capital. The hope is that lower upfront capital costs, learning effects from serial deployments, and designs that leverage greater offsite design and manufacture will improve the bankability of the technology. SMRs have emerged as a potential solution to attracting capital for an industry that witnessed the bankruptcy of Westinghouse after cost overruns building larger plants at VC Summer and Vogtle.

Even then, as the recently canceled NuScale-UAMPS CFPP project has shown, FOAK SMR costs paired with lower cost alternative energy supply led to "undersubscription" and the termination of the deal. The high investment needed, relative to the balance sheets of utilities and vendors that could build new nuclear in the US, is a binding constraint, and finding additional ways to loosen it would inject new dynamism into the industry.

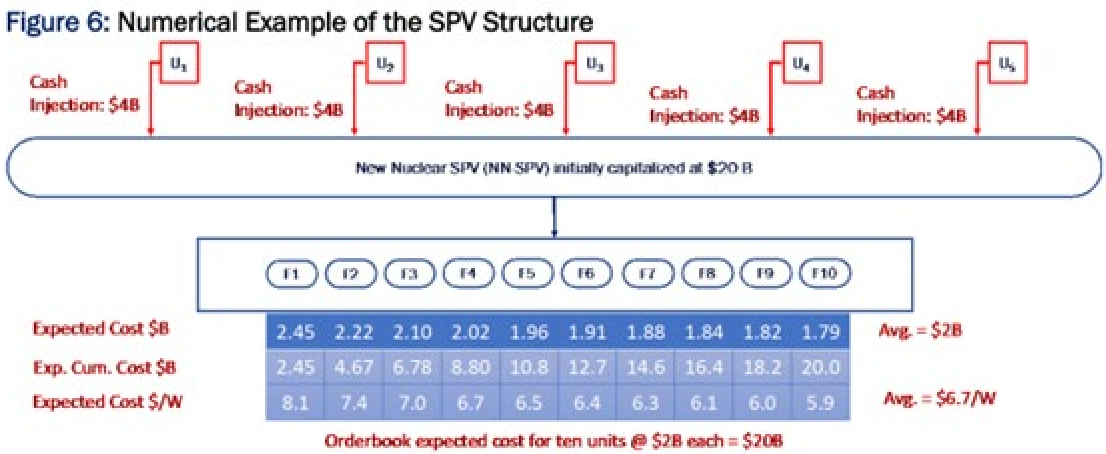

Figure 48 (EFI Foundation, 2023)

Most of the structures discussed so far have been some form of recourse[9] balance sheet financing. To date, non-recourse project finance has not been used for nuclear despite its prevalence in other energy projects. Sainati *et al.* point to tensions specific to nuclear: non-recourse finance requires "low completion risk and strong security interest for lenders", while nuclear projects are saddled with "prescriptive regulatory requirements" that conflict with the legal structure of typical project financing arrangements, alongside "extensive completion risk." In addition, nuclear projects are subject to strict and exclusive liability regimes that limit risk transfer, and, in spite of existing insurance and liability limits, weigh against the use of project financing.

[9] Recourse financing refers to any financing secured by the borrower's assets in the event of default.

Table 4. The different combinations of risks allocation arrangements and financing arrangements on nuclear projects in liberalised and regulated markets

Type of reforms	Decentralised market industries with IPP companies	Decentralised market industries	Liberalised industries with large vertical companies	Liberalised industries with medium-size vertical companies
Reference case	South Texas Project	Finnish plant Olkiluoto III	French EPR Flamanville 3	UK projects US project Eastern Europe projects
Allocation of construction risks	On Government *Standby insurance Governmental loan guarantee on 80%*	On Vendor *Turnkey contracts*	On producer	On producer consortium
Allocation of market risks on consumers	PPA with municipalities / historic suppliers	PPA with large industrial users / historic suppliers	Large base of sticky consumers	Large base of sticky consumers
Structure of financing	Project finance	Hybrid finance	Corporate finance	Corporate finance
Capital structure ratio debt/equity	70/30	75/25	50/50	50/50
WACC In nominal	9.2%*	5%	9.3 %	NA

*Assumptions : Normal financing conditions equivalent to those on coal and gas generation projects with 12% of Return on equity and 8% of interest rate on debt in nominal and after tax.

Figure 49 (Finon & Roques, 2008)

These financing approaches have all strived to lower perceived risk and the cost of capital, which we've seen is a major and sensitive component of nuclear levelized costs. Innovations and policies that reduce this crucial element of costs will go a long way in securing the baseload power needed for the energy transition.