TECHNICAL REPORT JUNE 2026

Clean Firm Power

Complementing Variable Renewables and Storage for a Fossil-Free Power System

FCA Future Cleantech Architects

fcarchitects.org

Executive Summary

Europe's electricity system stands today at the confluence of multiple potent trends: the drive to decarbonize for climate reasons, the pressing need to jettison fossil fuel dependence for energy security and geopolitical concerns, the need to unlock lower electricity prices for economic and industrial competitiveness, and rising demand due to electrification and new loads such as data centers. All of these mean that Europe's supply of clean electricity must increase substantially for the years and decades to come. Every electron counts, but not all electrons are equal: A "firm" one is more valuable than intermittent power. Clean firm power designates a class of power generation technologies that deliver clean electricity in a controllable way, whether as baseload or dispatchably. It is part of a portfolio of flexibility tools working together to complement the massive deployment of variable wind and solar, and as such they are indispensable to reaching an economically optimal, fully decarbonized electricity grid, which is itself the cornerstone of economy-wide decarbonization. With clean firm power, Europe has significant techno-economic potential to produce many more "firm" electrons.

- **Hydropower** serves as an essential existing pillar of flexibility, and while its expansion in Europe is geographically limited, its value should be preserved and extended through modernization and digitalization of existing fleets.
- **Nuclear power** is historically proven to provide reliable, low-carbon energy but is struggling in Europe today. If it is to survive beyond the lifetime extension of existing plants, its future depends on moving past the era of bespoke, isolated projects and returning to fleet-scale programs, whether with conventional or small modular reactors.
- **Next-generation geothermal** represents an untapped frontier with the technical potential to supply Europe's electricity demand many times over. By leveraging the drilling expertise of the oil and gas industry, geothermal can transition from a niche hydrothermal resource to a widespread one.
- For all clean firm power technologies, moving from baseload to dispatchable operation where possible is important to physically and economically complement variable renewable output. Other revenue streams such as providing heat directly rather than electricity also represent promising paths to market.

Yet despite this systemic value, clean firm power deployment will not happen in the market without more supportive public policy. This is normal; after all, batteries and renewables are thriving today in large part thanks to earlier government support. Crucially, this support needs to be multifaceted to address a wide range of obstacles: from derisking investment (e.g. exploration guarantees for geothermal, low interest rates for nuclear) for these technologies with high capital expenditure, to streamlining the regulatory process to accelerate projects.

On the pathway to deployment and tangible impact, scale matters considerably; in more colloquial terms, for clean firm power to be worth it, Europe must "go big or go home." The more Europe coordinates deployment of clean firm power, the easier it will be to reach a critical mass of projects that can sustain supply chains and lower costs over time. This does not mean that clean firm power should aspire to supply the majority of Europe's electricity and replace wind and solar, but rather that in order to complement these effectively, clean firm power cannot be reduced to a fragmented set of piecemeal projects. The oil crises of the 1970s spurred France and Sweden to achieve energy independence by building whole fleets of clean power generation, not one-off projects in isolation; today, Europe faces a challenge of even greater magnitude, and its ambition should rise to the occasion.

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Background

The Missing Piece for Abundant Electricity

Modern economies are intensely dependent on the second-to-second supply of electricity near-perfectly matching our demand. This dependency is due to the enormous value we derive from continuous electricity supply powering millions of things, from lights and laptops, conveyor belts and welding robots, to refrigerators and ventilators in hospitals. This is also what makes energy policy such a high-stakes problem. But while reliability is still the goal for the grid, we are long past the heyday of baseload power plants that were the historical bedrock and focus for our power system planners. Matching supply to demand in today's dynamic world requires just the opposite approach: nimble flexibility.

In a new age where the cheapest way to generate electricity globally is variable renewable electricity (VRE, see Figure 1) [1], we can no longer afford the inflexible ideal of steady consumption and generation we had historically. Furthermore, ongoing conflicts make it painfully clear that Europe's energy dependency is a major vulnerability that can be weaponized by adversarial foreign regimes.

Fully harnessing the trend of ever cheaper solar panels and wind turbines will, however, require new complementary tools to achieve a higher penetration of VREs. To meet the challenge, Europe is still missing a key component of the energy system: **"firm" generation that can be dispatched at will while being clean and affordable.** To accommodate the rise and fall of renewables and especially to bridge the occasional longer shortfall ("Dunkelflaute"[1]), we need to tap into flexible resources such as geothermal, nuclear, and hydropower.

It is important to say that firm power cannot be a replacement for variable renewables, as some suggest. It is also not true that firm power is required to prevent events like the Iberian blackout of 2025; thanks to grid-forming inverters, renewables and storage can deliver a stable system on their own. On the contrary, inflexible legacy baseload plants like coal and nuclear face substantial economic threats from VREs, even in the absence of further policy interventions.

Because VREs have become so cheap to build and have close to zero variable operating costs, competition between VREs in efficient liberalized markets forces them to sell their electricity at near zero prices[2] during ever more frequent times of excess generation. So, with prices falling way below the cost of coal and nuclear fuel rods ever more frequently, plants that were once considered "baseload" have to be switched off increasingly often, taking ever larger chunks out of the once-constant revenue streams their owners could previously rely on to recover high fixed costs [1], [3].

Firm power not only needs to become flexible for its own economic survival, it also has an important gap to fill in the energy system. VRE shortfalls cannot be affordably covered by only building batteries or gas turbines if most of them are rarely used outside a Dunkelflaute [4]; we can afford it even less if the turbines were to be fueled with more expensive green hydrogen. However, just like the idea that we must choose between a VREonly or firmonly system is a false dilemma, complementary firm power is also not in opposition to energy storage. Rather, innovators must tune the tool of flexible firm clean power to maximize its complementarity with the rest of the system, especially with short-term energy storage.

To successfully fill this gap, Europe's leaders must not only resist the calls to rewind the clock to the times of cheap foreign gas, but they must also pave the way with investments in a diversified portfolio of policy measures: mapping resources, cutting red tape holding up innovators and prototypes, and incentivizing the operational flexibility of existing assets. Betting it all on one option like hydrogen is insufficient. Yet policymakers still need to act decisively if they are to deliver a clean and robustly secure power system that their voters will not only find affordable, but genuinely cheap enough to unlock prosperity and industrial competitiveness. Beyond solving the problem of energy

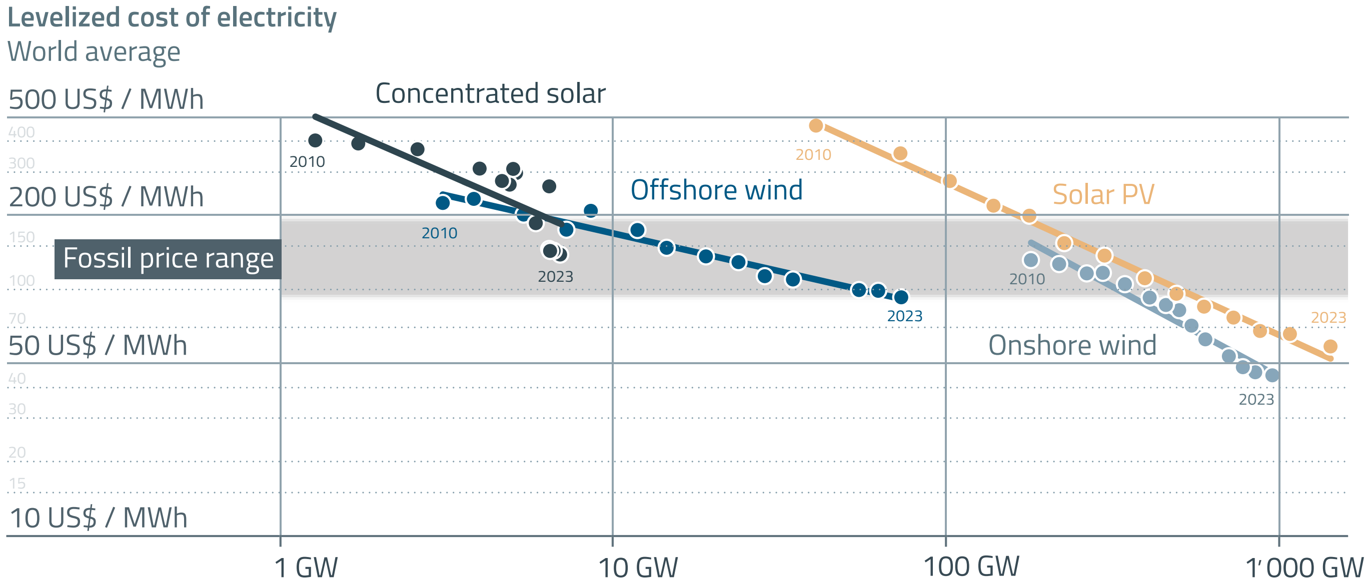

Figure 1: Levelized cost of electricity of variable renewable energies [2]

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[1] *Dunkelflaute* is a German word that in energy circles refers to a prolonged period of low wind and solar generation, e.g. a week of low wind in the middle of winter in Europe. An equivalent English expression sometimes used is "dark doldrums," but this is less common. Its direct opposite, the *Hellbrise*, is a period of high solar production that coincides with strong winds, but this term is also uncommon as of yet.

[2] This phenomenon is becoming more frequent and is often termed "cannibalization," as it is detrimental to renewables themselves since it lowers their own revenues.

security, there are valuable opportunities to be seized here: As technology advances, more and more uses of energy can be switched from fossil fuels to electricity, which is almost always a much more precise and clean application of energy than the inefficient[3] and polluting fossil alternative. More often that not, the result is higher efficiency, better performance, and lower cost.

As long as this transition to a competitive modern economy is not derailed by high electricity prices and grid fees, political inaction, and incumbent foot-dragging, people will increasingly opt for the electric option. They will buy cheaper electric cars or install heat pumps, and more and more of such products will contain clean homegrown materials such as green steel made from clean electricity rather than coal. Achieving this requires reducing electricity prices while total demand roughly doubles [5], and hence we need every tool in the energy system toolbox, as well as some out-of-the-box thinking.

However, if Europe does manage to leverage its strengths in innovation and is able to integrate flexible and variable clean energy generation well, the synergies achieved will keep European entrepreneurs competitive, sustain existing skilled workers' jobs while creating new ones, and put an end to the era of expensive and geopolitically risky European energy dependence. With steps like the Net-Zero Industry Act, policymakers have been moving in the right direction. Many more opportunities for impactful policy remain.

In this report, we will lay out the case for why there is great value in developing and deploying complementary clean firm power technologies alongside variable renewables and other flexibility options. We will also explain and discuss several examples of clean firm power technologies and the traditional and new approaches within, highlighting some of the gaps that must be closed to make those technologies competitive and complementary in markets becoming more and more dominated by renewables.

Emissions from Electricity

Box 1

Citizens of growing middle-income countries[4] can increasingly afford to expand their power systems and to use more electricity [6]. Indeed, the last decade has been the first time in the history of electricity generation when the number of people without access to it fell below one billion [7]. However, electricity generation contributes 14 Gt of greenhouse gas (GHG) emissions, around a quarter of the global total. According to the model expressed by the Kaya equation below, these emissions are driven by the factors of population, gross domestic product (GDP) per capita, electricity intensity of economic activity, and emissions intensity of electricity production[5].

$$\textit{GHG emissions} = \textit{population} \times \frac{\textit{GDP}}{\textit{capita}} \times \frac{\textit{electricity}}{\textit{GDP}} \times \frac{\textit{GHG emissions}}{\textit{electricity}}$$

Most of the factors in the equation are growing, in particular global GDP, but population is also still rising. This means that emissions from power generation will increase massively unless energy efficiency improves[6] and the carbon intensity of power generation decreases sufficiently fast (see Figure 2).

It also shows that the regions on Earth where most future emissions are to be avoided are where population growth, economic growth, and electrification will be concentrated. While emissions in Europe are still clearly far from negligible[7] [8] and there is a long road ahead to decarbonize its economy, leveraging the talent of European scientists and entrepreneurs and exporting innovation to international markets is one of the most effective ways to help address this majority of future emissions beyond our borders. As a corollary, solutions that rely on a willingness to pay high green premiums and which only the citizens of rich countries can afford will contribute much less to fighting climate change.

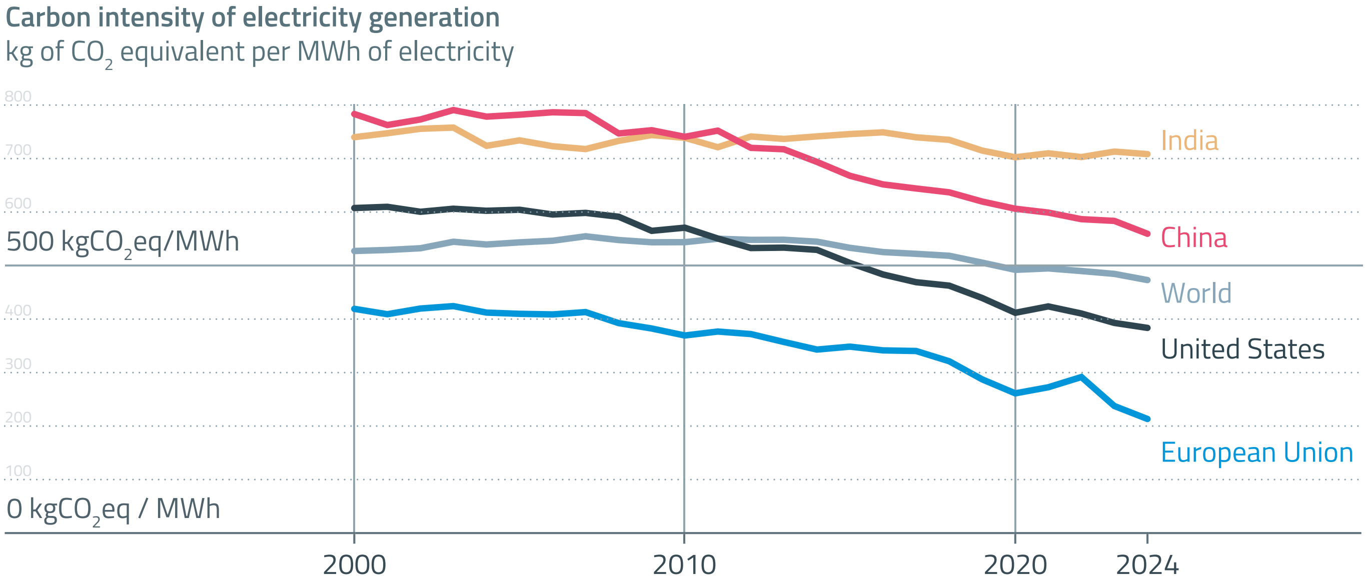

Figure 2: Carbon intensity of electricity generation ($gCO_2/kWhel$) for selected regions, 2000-2023. While it is falling globally, this needs to be accelerated further to reach Net Zero targets.

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[3] Fundamentally, this comes down to the fact that burning fuels always produces heat and requires inefficient conversions for the many non-thermal applications of energy that society uses, which can be delivered much more effectively with the precise tools of electrical technology.

[4] The World Bank categorizes countries as "low-middle income" and "high-middle income" based on regularly adjusted gross national income thresholds, which are US$1,146–4,515/capita and US$4,516–14,005/capita, respectively, in 2025. The two categories encompass about 75% of the global population.

[5] The model is restricted to electricity here, rather than encompassing all forms of energy.

[6] A full discussion of energy efficiency is outside the scope of this report, but it is always the essential first step in decarbonizing and vast opportunities remain for improvement. Consider for example that the energy use per capita in North America is around twice as high as in Western Europe, while living standards are comparable.

[7] In 2023, the European Union accounted for 6% of the world's GHG emissions. The fraction of future emissions that can still be avoided is significantly smaller.

The Triumph and Challenge of Renewables

Dominance of Variable Renewables

Before understanding the need for complementary firm power, it is important to realize that these technologies will operate in an environment shaped in every aspect by variable renewables. The reasons behind this hold important clues for taking firm power into a more flexible future.

Wind and especially solar are set to dominate the global energy landscape, even in the absence of further policy, thanks to their dropping costs and short deployment timelines [1]. This is even more true given the continuing support from existing policy frameworks. The fact that the cost of a technology tends to decrease continuously with its cumulative deployment is a well-known observation in the study of technology diffusion [9], [10], [11], [12]. Among other things, processes like learning-by-doing on the factory floor and continued material refinement in the lab are driving this improvement in efficiency and productivity. For example, the price of solar modules falls by 20% with each doubling of cumulatively installed capacity globally, resulting in a 99.6% drop from 1976 to 2019 [13].

Costs can keep decreasing year by year even though a technology may already be used widely, as wind and solar show. This is because the relationship between unit cost and cumulative deployment is true over many doublings of deployment. As the history of solar shows in Fig. 3, it is easy even for experts to underestimate deployment and cost reductions [14]. Starting in the lab, most technologies are not competitive with incumbent technologies in the market. However, initially going down the cost-deployment curve is nonetheless possible with specialized niche markets (Cold War satellites and early calculators in the case of solar); this is often where governments have a critical role to play in supporting early demand to kick off learning curves that ultimately become self-sustaining (e.g. see the policy support schemes for solar photovoltaic in

Fig. 4). Even in later stages of deployment, when economic and technological momentum have already built up, it may be in a country's interest to proverbially keep the foot on the accelerator, i.e. to provide continued support, to arrive at the lowest cost more quickly and reap the benefits earlier.

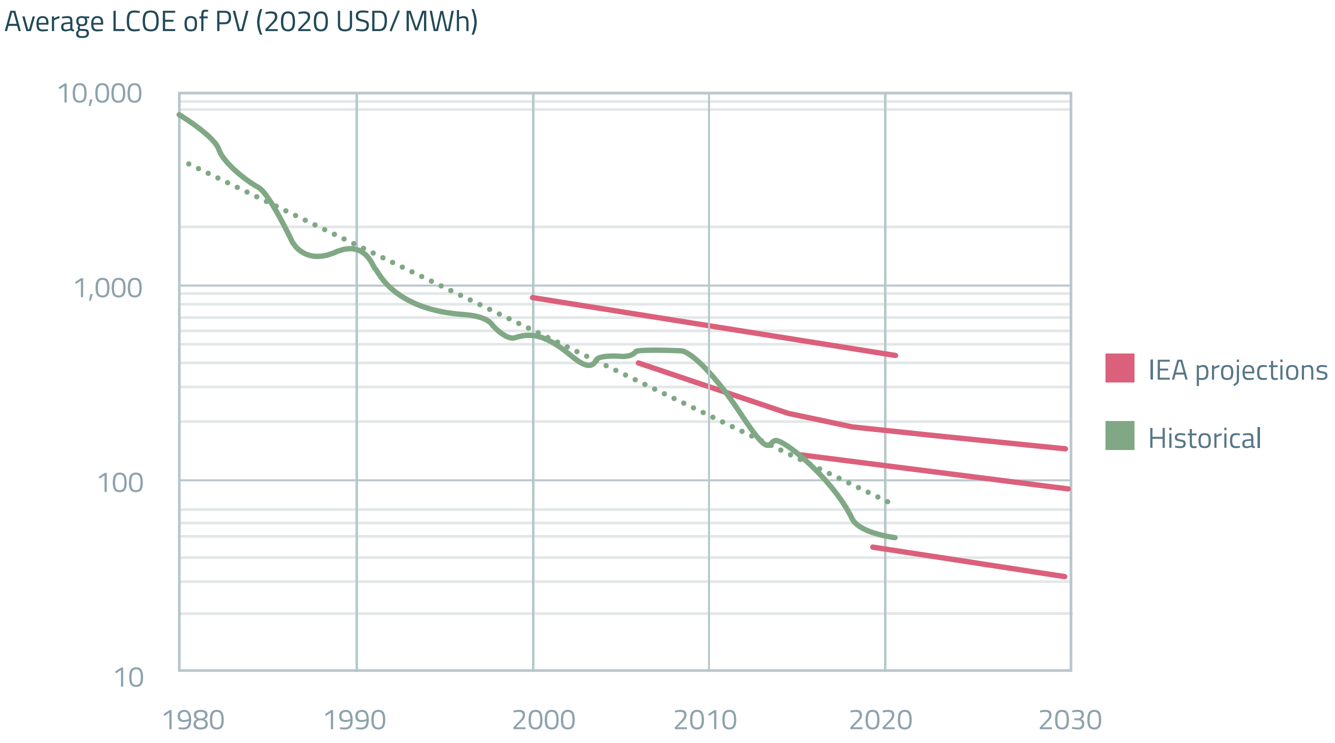

Figure 3: Historical data on the levelized cost of electricity of photovoltaic (green line; trendline is dotted) versus projections from the International Energy Agency (red lines). Data from Way et al. [14]

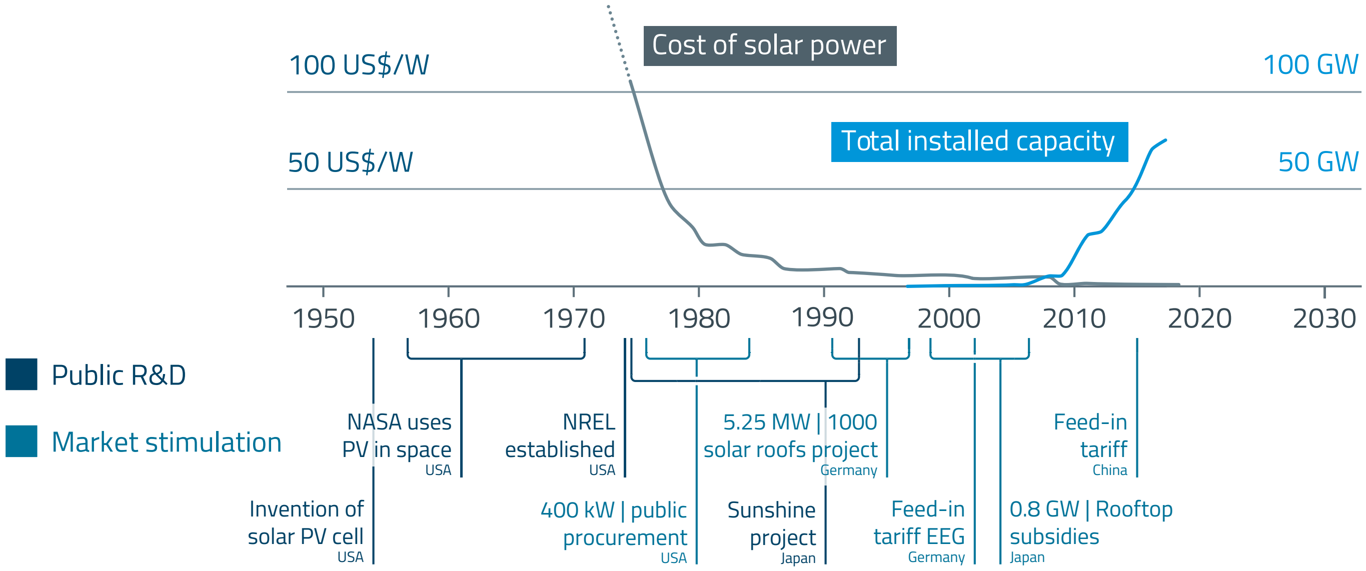

Figure 4: History of solar photovoltaic policy support, cost, and deployment

The continued triumph of renewables has now reached a point where utility-scale solar has the lowest levelized cost of electricity (LCOE) of all electricity generation technologies in most places on earth. Even where LCOE is still somewhat higher, for example because of higher installation cost and less wind and sun, renewables can be broadly competitive. Due to the way energy markets typically operate (see Box 4), renewables are almost always scheduled if they can run,[8] as they have essentially zero variable cost. In contrast, for fossil plants, fuel costs have a large effect on economics, so needlessly burning costly fuel while free renewable electricity is available would be inefficient and expensive. This allows renewables to take away market share from baseload, mid-merit, and peaker plants alike, up to relatively high VRE percentages. Nonetheless, it is widely acknowledged that LCOE does not give the full picture of an energy system's costs [15] since it leaves out balancing costs for intermittent resources. This is where complementary firm power comes in.

The Importance of the Electricity Market Perspective

Box 2

In Europe, electricity is traded freely on markets, specifically on liberalized, competitive, auction-based wholesale markets. The way these markets work strongly determines how electricity is produced and consumed, both on the hourly scale and on the scale of investment timelines. It is thus crucial to consider the market perspective when evaluating how successful and competitive a technology will be, and how it will be used.

We can summarize two key takeaways from the market perspective for complementary firm power:

- **VRE technologies like solar and wind will be scheduled before dispatchable power technologies by default.** The market mechanisms enforce a *merit order* based on the underlying logic that stored energy like fuel or reservoir water carries value, and their use is inefficient when free renewable energy is available. Operators of dispatchable power assets must therefore adapt to hourly renewable production.
- **Clean firm power technologies must operate more frequently or lucratively if their capital cost is higher.** The lifetime revenue of a plant must cover variable expenses like fuel, but also the initial investment, a risk-appropriate return, and other fixed costs. Equipment sitting idle for large parts of the year is only economically feasible if it has low capital cost, or prices are sufficiently above average when it does get called upon.[9] Investors must therefore choose technologies that have low CAPEX or can be used during most hours of the year.[10]

Keeping the market perspective in mind is important, because conceptualizing power system operations as actions that could have been ordered by a central planner is often useful but can be misleading. For example, in this report we note that variability needs to be "managed," that firm power must "complement" renewables, or discuss a "strategy" of "overbuilding" renewables. Such descriptions are shorthand to refer to decentralized developments of the power system that are mediated by market-based interactions of many individual economic actors, and only broadly and indirectly steered by policymakers.

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[8] When they are curtailed, that is most often due to a bottleneck in the grid that physically limits the delivery of the available power.

Main Flexibility Tools and Their Gaps

The Two Main Challenges with Variable Renewable Energy

With the potential and benefits of variable renewables being so large, it is critical to address the challenges of integration. To understand what firm power can contribute, it is important to understand where our current integration solutions are lacking. Wind and solar are not only variable, but also inflexible. Moving from a fossil-fueled system to one running on renewables thus requires adding new forms of flexibility. This flexibility requirement can be conceptualized as the need to address basically two archetypes of increased variability:

- *More short-term periodic variation because of day–night cycles (especially for solar):*
  - Renewable output combines with the rise and fall of demand to produce mismatches to be managed, typically on a timescale of hours. Fossil generation is dispatchable and can run as baseload.
- *More long-term stochastic or "random" variation and stronger seasonal cycles because of weather dependency:*
  - Renewable production can fall short almost completely, for days or weeks (Dunkelflaute), and it introduces seasonal patterns of supply which add to seasonal demand variability. Fossil generation is affected by unpredictable factors as well, but such events are usually not correlated across the entire system, and there is little seasonality in supply.

More short-term periodic variation is the easier challenge as it simply means there are more sources of daily periodic inflexible variation to manage than before. In the past, fossil generation adapted to inflexible demand. Now, cheap variable renewables both reduce the utilization of dispatchable capacity and add their own inflexible periodic patterns to be managed. One example is illustrated in Fig. 5: Generation typically has to be ramped up in the mornings and evenings, to adjust to demand peaks. For a system with high solar penetration, when the sun sets, dispatchable output like gas-fired turbines or batteries needs to ramp up much more to compensate both for rising demand and for falling inflexible production, and in general such flexible generators must be a larger part of total capacity, at the expense of baseload generators.

Renewables add supply variability to demand variability
More and faster ramping of dispatchable sources is required

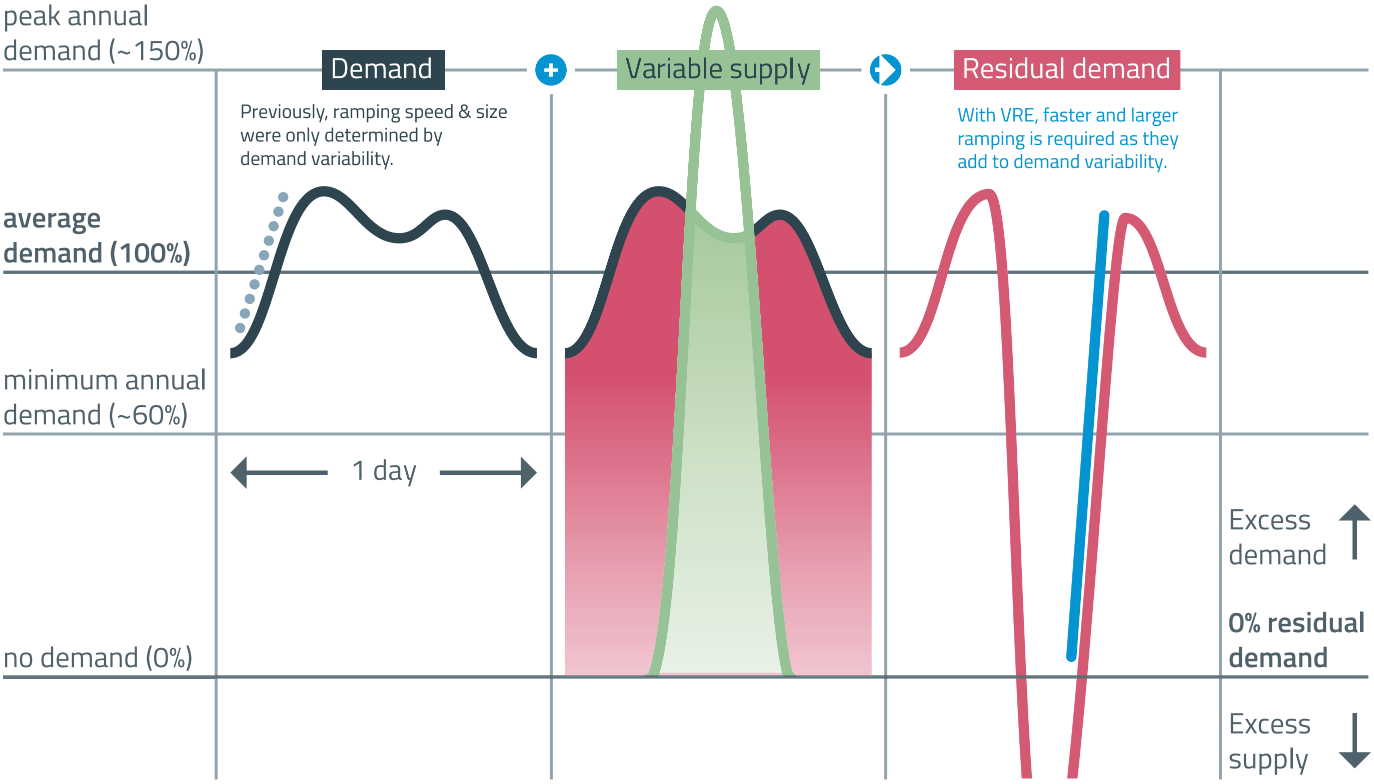
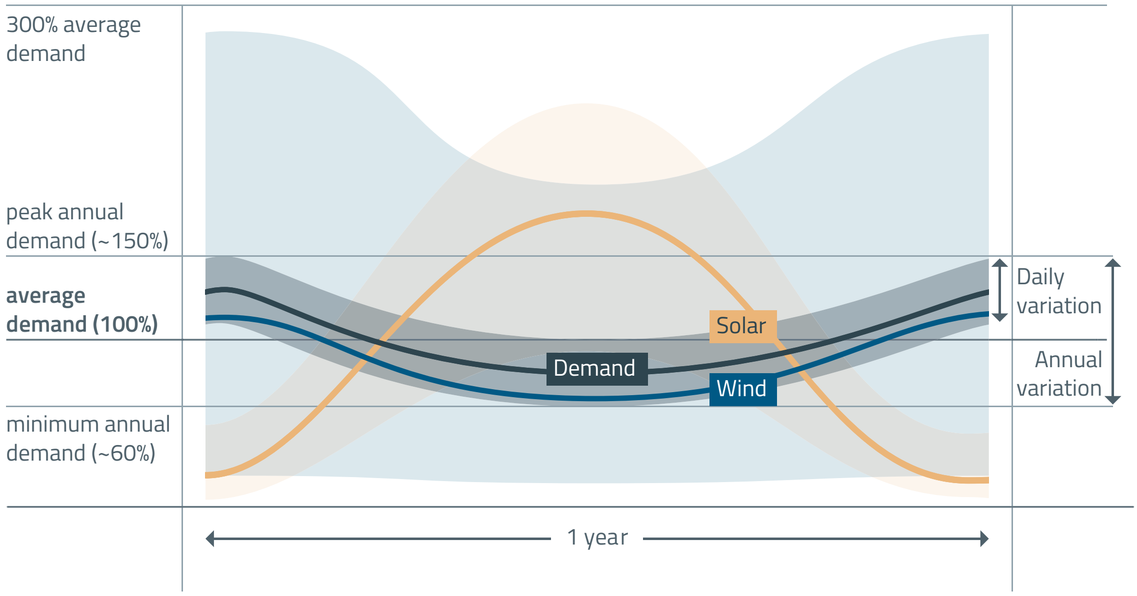


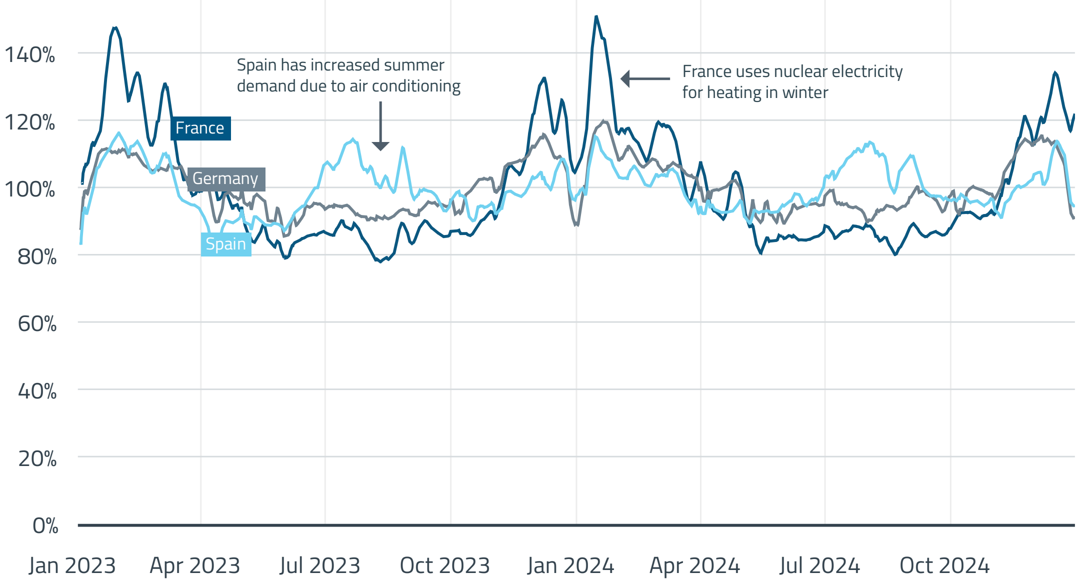
Figure 5: More short-term periodic variation because of day–night cycles: Renewables add supply variability to demand variability. This illustrative example shows how the daily requirements of adjusting production up and down change with inflexible variable supply. Ramping requirements for following demand variability only (grey dotted line) are smaller in magnitude than when variable and inflexible supply is present in the system. The residual demand curve has much steeper and higher slopes (blue line). Note that the system sketched here is somewhat extreme as it is solar only, to show the effect more clearly. Daily variation as well as peak and minimum demand are roughly representative of Germany but also broadly match other European grids.

Larger-scale and medium-/long-term stochastic and non-periodic fluctuations are a new challenge. This is different than just managing daily demand variation and requires dispatchable power that is independent of renewables over longer timespans. Demand follows mostly short and predictable social rhythms such as work hours and weekends; even for longer timescales, planners can be certain that heating is turned off in the spring and back on in autumn.[11] While predictability facilitates efficient planning, for example of natural gas storage capacity and inventories, the aspect of demand variability that makes it relatively easy to deal with is that demand almost never strays beyond a relatively narrow band between daily peaks and night-time lows. Even when there is pronounced seasonal demand variability, the minimum and maximum demand tend to be no more than 50% above or 25% below the average demand (see Fig. 6). Still, seasonal renewable output patterns can exacerbate – but also counteract – seasonal demand patterns, which are becoming more relevant as electrification advances and the seasonality of the heating sector becomes increasingly important for electricity. As a result, the minimum and maximum annual demand may move further apart.

a) Seasonal demand variability is less significant than daily renewable variability
Wind and solar seasonal variabilities tend to offset each other



b) Demand relative to national annual average (7-day mean)



Spain has increased summer demand due to air conditioning

France uses nuclear electricity for heating in winter

Figure 6: Seasonal demand variation is confined to a relatively narrow band around the annual average. (a) The daily variation of demand is approximately of the same magnitude as the annual variation of minimum and maximum demand. Even with the pronounced seasonality in wind and especially solar output shown in this example, they significantly offset each other, making the overall output much smoother (not shown). Note that the seasonality of solar and wind sketched here is very strong, representative of the climate in northern, wind-dominated countries like Germany. The height of the illustrative wind and solar production curves shows the output corresponding to a capacity that would supply an annual output equal to the annual demand. As this is based on long-term averages, such a system would still need seasonal storage or firm power to both bridge the seasonal gap between average monthly demand and supply and to bridge the gaps arising from to random variation, which is evident in (b) which shows real demand data from France, Germany, and Spain over two years.

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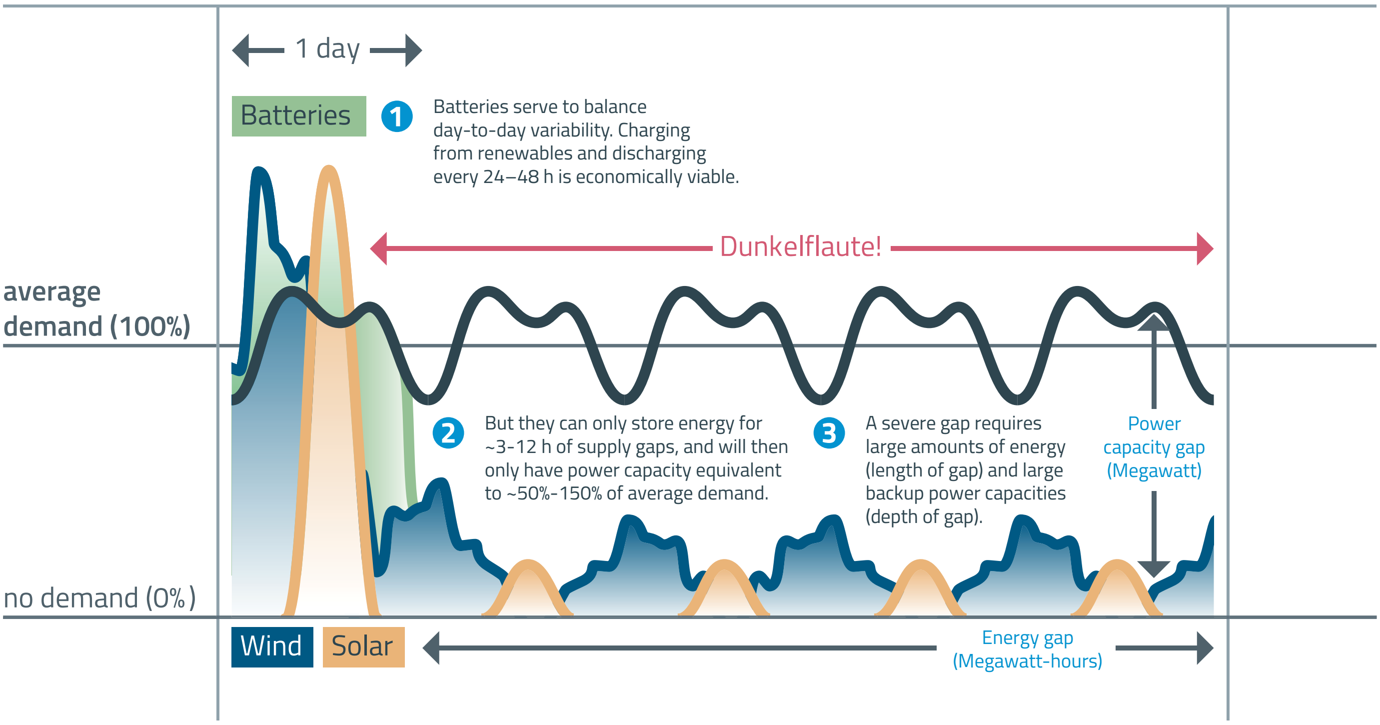
[11] Especially in Europe. In geographies such as the United States, there is also a demand peak in summer with air conditioning.

In contrast, the character of long-term variability from renewables is different: Wind can die down almost completely for weeks at a time, and cloud covers can blanket entire countries for days, hobbling every solar panel at once. This can lead to long and large-scale shortfalls of virtually 100% of the average production that have no analog in terms of demand fluctuations (see Fig. 7). Still, such longer severe shortfalls are infrequent: The worst Dunkelflaute events, on the scale of weeks with a near 100% reduction of renewable output relative to the average, are once-in-a-decade events. Studies with models using very long duration storage or seasonal storage frequently find that including more weather years raises the calculated need for storage capacity; only multi-decade data gives reliable results [4], [16], [17]. On the other hand, fossil fuel supply is arguably just as unpredictable on these timescales, if not more so, given that weather and climate are easier to measure statistically and to predict a few days or weeks in advance, compared to the influence of trade disputes, oil cartels, and wars.

7a)



7b)

Variable renewable production (GW) during a Dunkelflaute
Illustrative 3 GW wind-solar mix for Germany based on historical weather data

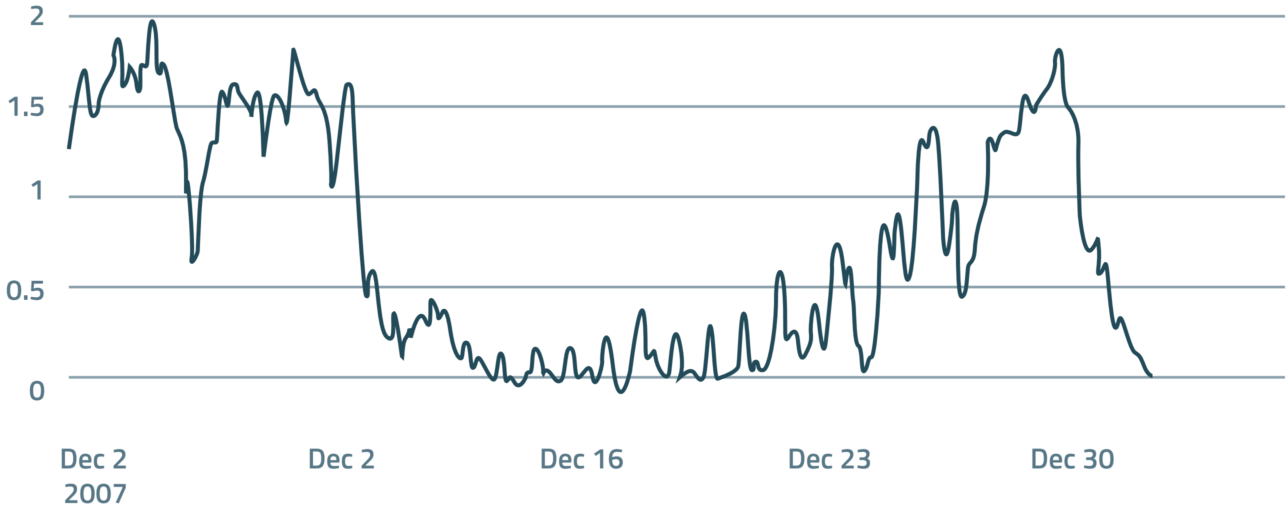


Figure 7: A Dunkelflaute, i.e. a longer and more intense shortfall of renewable energy supply because of weather dependency. (a) is a conceptual representation and (b) is a real-world example. A winter Dunkelflaute is all the more problematic in Europe given that energy demand peaks during this season due to heating requirements (a challenge for the grid if heating is electrified).

The Two Current Main Tools to Address VRE Challenges

As there is so much to be gained from solving the variability challenge, many approaches are being discussed and developed. Typically, the focus lies on two broad categories, which cannot address long-term variability but are good solutions for predictable and short-term variability:

- Energy storage (battery or other short-duration technologies) which shifts energy in time to make renewables flexible.
- Renewable overcapacity, to reduce the frequency and severity of shortfalls at the expense of more curtailment, and to have flexible reserves for increased demand or to charge storage.

Both solutions are critical and very effective for dealing with short-term variability, so they likely will play a large role in almost all energy systems across the globe.

Energy Storage

The storage systems considered here are typically envisioned to be batteries, but similar points apply to other short-duration storage technologies.[12] The key point is that the available technologies have relatively high costs per kWh of storage capacity (currently ~125 USD/kWh[13] [18], although costs are falling) and high efficiency in charge and discharge (~90%). These storage systems take advantage of arbitrage opportunities in the market, charging when prices are low and discharging when prices are high. Many cycles per year means more opportunities to cover fixed costs, which is very important for a relatively expensive storage technology like batteries: It is necessary that they make use of their capacity as often as possible, to spread their cost over many MWh of sold electricity. Together, these characteristics make batteries a good fit for the daily shifting of inflexibly produced renewable energy (flows) to times when it is more valuable, by storing it for a short time (stocks). Modeling power systems using wind and solar generation portfolios optimized for regional conditions together with 12 hours of storage can already cover demand in 83–94% of hours, depending on the location [19].[14] In the sunniest regions of the world (mostly outside of Europe), it is now even theoretically possible to get over 90% of the way to clean and reliable 24/365 generation with just solar and batteries[15] without exorbitant cost [20].

Renewable Overcapacity

Overcapacity or overbuilding renewables generally means that generation capacity is sized to meet the highest demand at a time of low wind and solar production. The goal is to have higher capacity available even when there is relatively little sunlight and wind, to still be able to serve demand at that moment. When the output is higher than demand during more favorable days, it is simply not used, i.e. production is curtailed.[16] This strategy's viability depends on the cost of building the renewables in question, as it effectively decreases their capacity factor, so investment costs have to be paid for by revenue generated over fewer hours per year. In addition, prices will decrease in hours where renewables are active as the supply of energy is increased, reducing revenue for all renewables, an effect sometimes called self-cannibalization. However, given the low cost of wind and solar, some level of overbuilding is almost always economic. On the level of a single utility-scale photovoltaic installation, it is standard practice to significantly oversize the peak capacity of the panels with respect to the grid connection (inverter loading). It is simply cheap enough to add more panels even though not all of the extra electricity they produce can be sold. As with batteries, the benefit of overbuilding also shows up clearly in modeling. Given that wind and solar resources tend to be anti-correlated on diurnal and seasonal timescales [21], power system planning should explicitly factor in this synergy rather than considering each resource separately: Power systems with optimized wind and solar portfolios overbuilt to produce 1.5 times annual demand are able to cover demand 83–99% of hours, depending on location, with 94% as the global average [19].

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[12] Long- and ultra-long-duration energy storage technologies are central to many debates and proposals as well, although they are further away from widespread deployment than batteries and similar short-duration storage technologies. In this report we separate them conceptually to be able to discuss them in the more general context of firm dispatchable power.

[13] For a utility-scale battery energy storage system (BESS) with four hours or more of storage outside the United States and China, according to global expert interviews led by Ember in 2025. The core equipment represents around 75 USD/kWh and installation adds about 50 USD/kWh due to EPC services (engineering, procurement, and construction) and grid connection fees (which range widely, from 30–100 USD/kWh, unless co-located with an existing solar plant). The levelized cost of storage (LCOS) is around 65 USD/MWh. Note that storage costs are still decreasing, at an average of 20%/year over the last decade.

[14] Assuming no regional transmission constraints, no flexible demand, and no overcapacity.

[15] In a sunny city like Las Vegas, 17 kWh of battery storage is enough to turn 5 kW of solar panels into 1 kW of 24/365 generation 97% of the time; the resulting LCOE is 104 USD/MWh, i.e. competitive with coal and nuclear.

[16] If one defines demand to include storage losses.

Box 3

Systems Thinking for Holistic Approaches to Complement Renewables and the Main Flexibility Tools

The reliability of clean power supply is a systemic challenge calling for a systemic approach, with a portfolio of complementary flexibility solutions working together.

- *Demand flexibility (also known as demand-side response or DSR)* in applications where it is cheaper than storage or overcapacity. It has hitherto barely been exploited as fossil grids provided all the necessary flexibility. Demand-side response works for time-insensitive use cases (e.g. washing machines, heat pumps,[17] charging electric vehicles[18]) and should be thought of as a spectrum rather than a binary (i.e. even without fully turning it on and off, the ability to partially flex the energy demand of an application is valuable). These sorts of operation modes are best handled by algorithms and so-called "smart appliances" rather than having users manually track electricity prices in real time to switch devices on and off. Demand-side response is also possible in some industries,[19] especially batch processes. Finally, if the hardware is already being deployed anyway, such as electric vehicles or heat pumps, then the cost of demand-side response deployment could be quite low and driven mainly by software or market coordination such as "virtual power plants" (VPP).
- *Grid expansion* to shift energy in space (e.g. East–West connections for solar [24]), rather than in time (as with storage). However, building new high-voltage transmission lines is a lengthy process. Streamlined permitting and so-called grid-enhancing technologies (e.g. reconductoring and dynamic line rating) can help alleviate this [25].
- *Innovative variable renewables,* such as wave and tidal, to diversify and thus decorrelate VREs even more and increase capacity factors, reducing demand mismatch and the frequency and severity of shortfalls. Even including some vertically-oriented East/West panels in a solar photovoltaic portfolio can help to smooth the production curve during the mornings and evenings, representing another form of flexibility that reduces the need for storage [26].

Overall, the most cost-effective pathway will usually be a combination of at least several of these flexibility tools, with the exact mix depending on the specific circumstances of the given region and how costs fall over time for each of these tools. These strategies are complementary and can together produce a much more resilient energy system than any one in isolation.

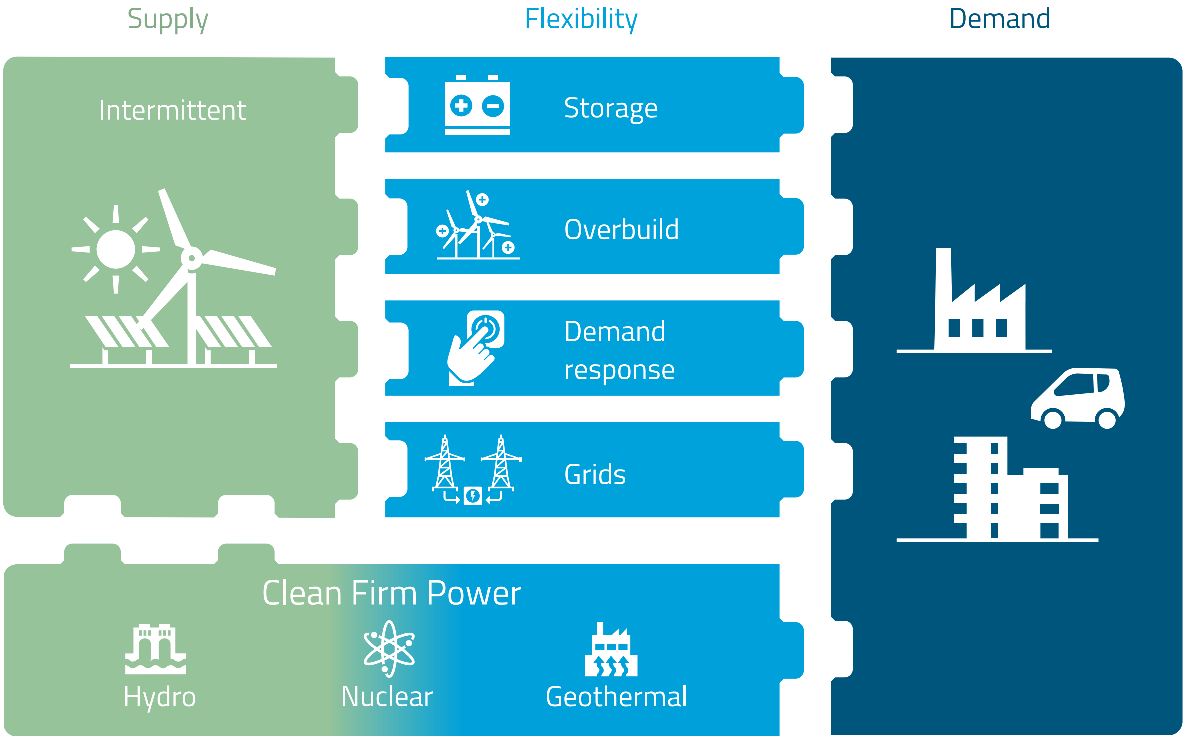

Figure 8: Flexibility tools working together to bridge the gap between supply and demand

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[17] Buildings have a certain amount of so-called thermal inertia, which means that when the heating is turned off, they cool down at a rate determined by their insulation and outside temperature. By taking advantage of this thermal inertia and the fact that humans are comfortable in a range of indoor temperatures (roughly 19–24 °C), a building can be "charged" up thermally by slightly overheating it during a period of abundant clean power and then turning down/off the heat pump if a period of scarce clean power follows. This enables at least a few hours' worth of demand flexibility for the heat pump and potentially three days' worth for well-insulated buildings [22]. UK studies from Octopus Energy's Centre for Net Zero have shown that time-of-use tariffs are very effective in shifting heat pump demand, doubling consumption during off-peak hours and halving it during peak hours [23].

[18] Going even further than demand response, electric vehicles also have the potential to discharge their energy back to the grid (V2G, vehicle-to-grid), which turns them into a form of distributed energy storage.

[19] Historically, demand-side response has even been predominantly an industry phenomenon, for sectors with more flexible loads and high electricity costs. As more processes electrify and are reinvented with the expectation of variable renewables taken into account, one can speculate that the requirement for steady-state industrial operation will become less common and/or less stringent.

Limitations of the Main Tools

While the two strategies of (short-term) battery storage and overcapacity can address a large part of the variability challenge, they cannot solve it completely. In particular, neither can solve the problem of longer, infrequent, and severe gaps in supply, i.e. the Dunkelflaute (several days duration, 80–100% shortfall, less than once a year) and seasonal variation (several months long, potentially more than 50% mismatch in severe cases, once a year). Here, modeling of pure wind and solar systems with up to 12 hours of energy storage and 1.5 times overcapacity shows they can reach 89–100% demand coverage, depending on the region (global average is 98% of hours covered) [27]. But even in regions with >95% of hours fully covered, this still leaves dozens of >24-hour periods of partially unmet demand, and these gaps can be wide: In countries like France, Germany, or the UK, there would be hundreds of hours with supply being below half of what is needed, as seen in Figure 9.

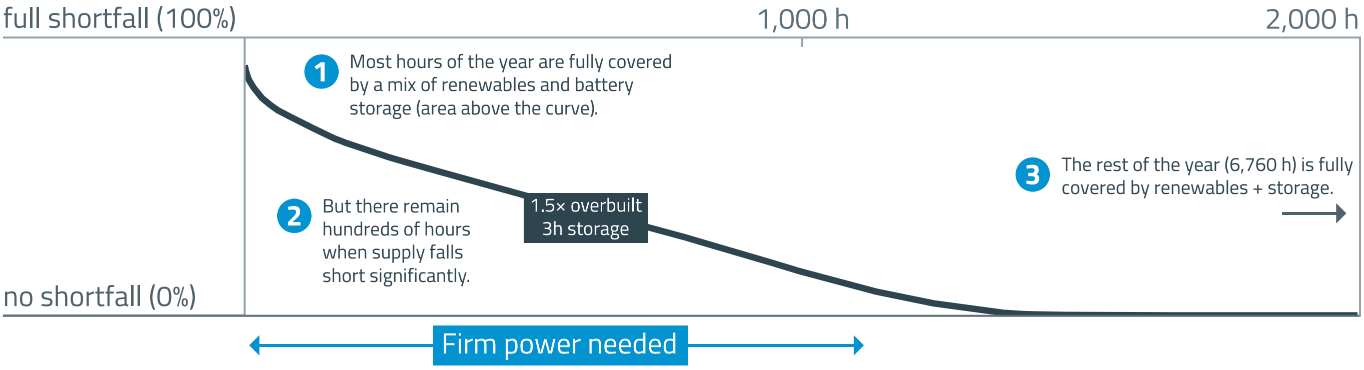


Figure 9: Durations and magnitudes of energy shortfalls in a fully VRE mix

No reasonable amount of overcapacity can compensate for the near-complete lack of renewable production during the scarcest periods, as can be seen in Fig. 10. Still, periods of scarcity are naturally not clearly defined by sharp boundaries and may not even be contiguous, with a windy day occurring between two calm periods of several days. Overcapacity would allow storage to recharge within such a window of opportunity, alleviating the scarcity somewhat.

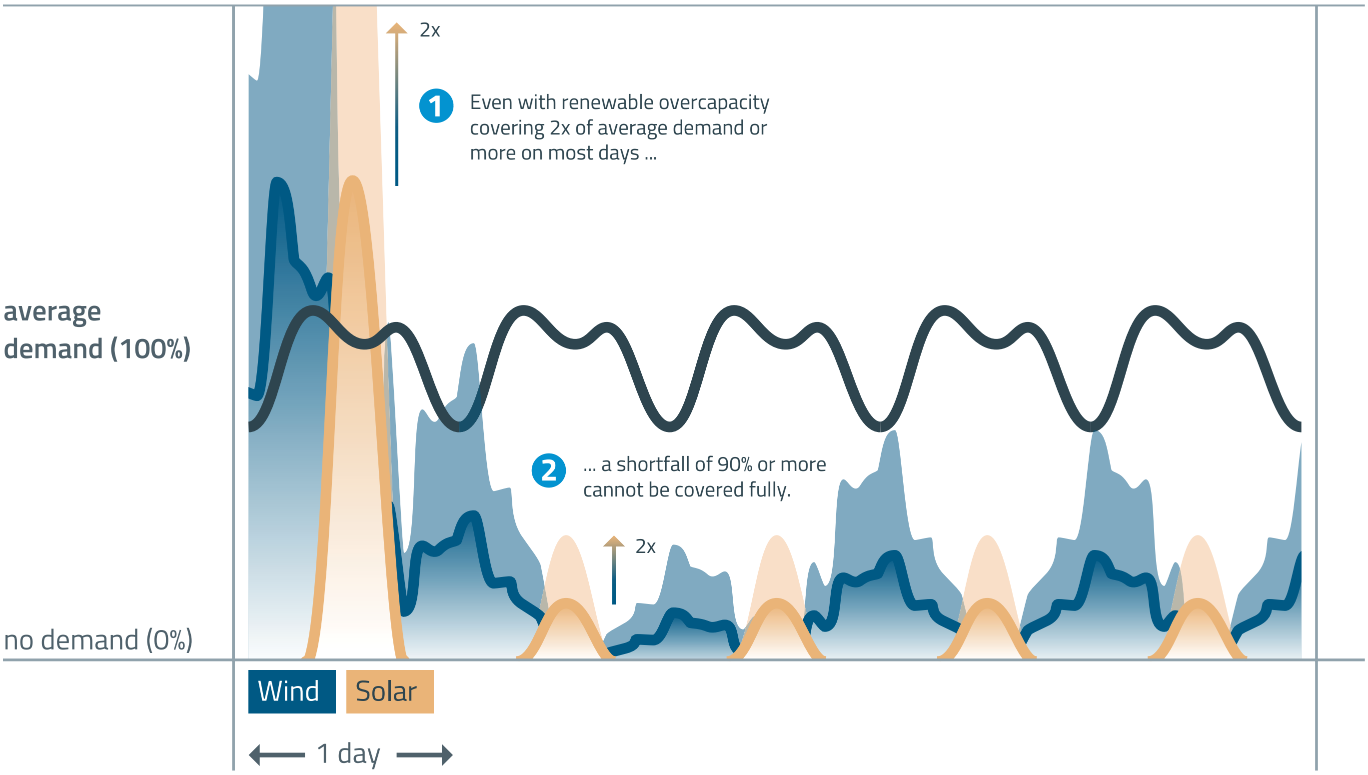


Figure 10: The limits of overcapacity when faced with a long period of a high shortfall

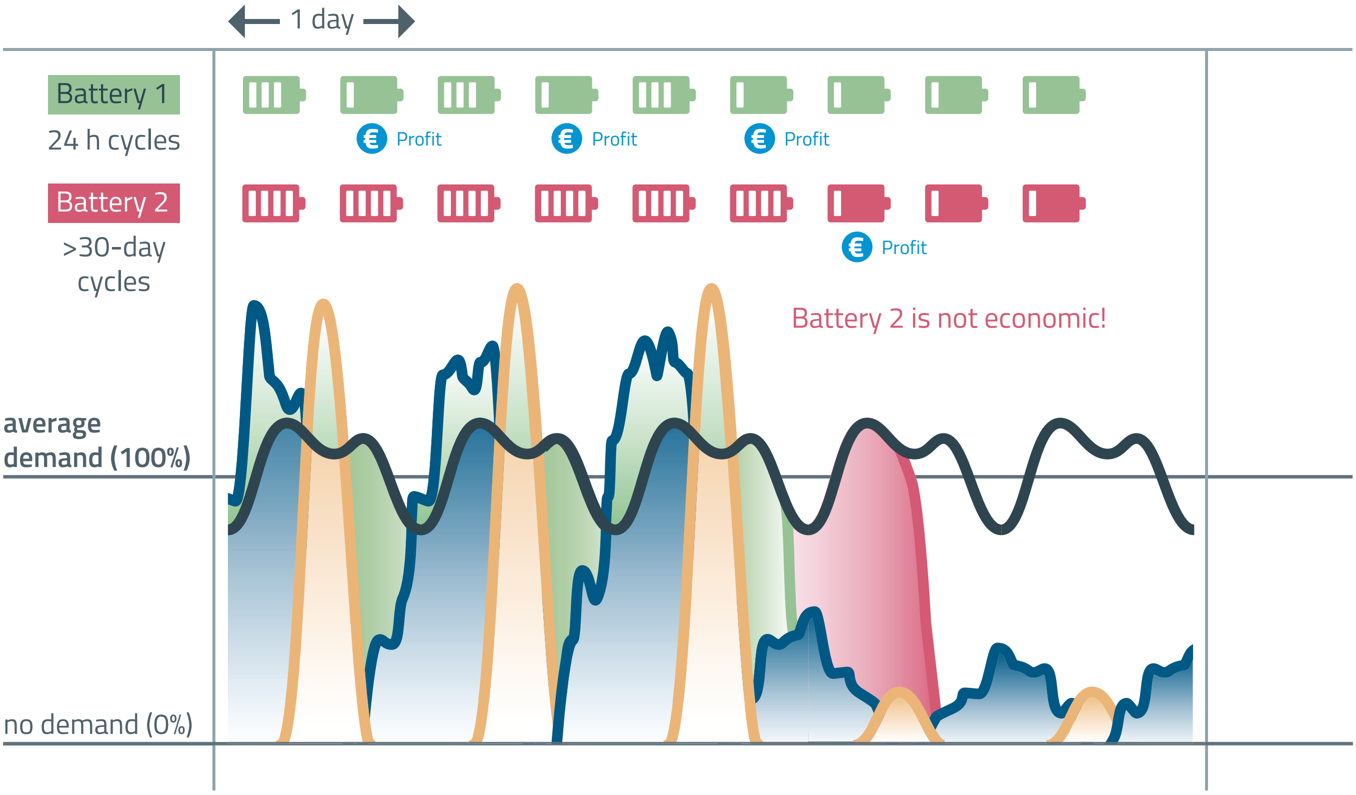


Figure 11: The limits of batteries for long-duration shortfalls. While batteries are economic for short-term mismatches, they do not work for Dunkelflaute.

Battery storage is unable to be a full solution because of the high cost per kWh of capacity for conventional lithium-ion batteries and similar technologies. It is considered a short-duration storage technology because using it to store energy for weeks or months is uneconomic (see Figure 11); it implies not cycling the battery enough over its lifetime to recover its investment cost plus a competitive return on investment. Nevertheless, batteries will play a critical supporting role during supply shortfalls just like overcapacity. For example, they can reduce the need for backup capacity by charging from firm generators during the night and covering the peaks during the day, enabling full use of the available firm generation during a Dunkelflaute.

The bottom line is that some form of firm dispatchable capacity – long-duration storage and firm power – is needed during prolonged and deep times of scarcity. While there are more flexibility tools than the main ones of overcapacity and batteries (see Box 3), all of which are needed for a holistic solution, they too are ill-suited to dealing with longer gaps in supply. So, some dispatchable capacity will be necessary, but which form exactly? And how can it compete with renewables and batteries outside the occasional Dunkelflaute? The clean options on the table are (ultra-)long-duration storage (e.g. hydrogen gas power plants) and firm power; in the absence of policy intervention, the default is definitely fossil gas.

Even with significant deployment and support for renewable overcapacity and battery storage, it would be very hard to achieve low enough costs to fully displace fossil gas with these tools alone. This is true despite the high fuel prices prevalent in the EU (above 25 €/MWh since 2021 [28]). Moreover, the goal to eliminate global emissions requires replacing gas everywhere, even where it is plentiful and cheap (e.g. below 5–10 €/MWhGCV, the typical price range in the US Henry Hub) and where carbon pricing will not come in time. However, even if gas can be displaced from day-to-day operations, the plants would still have to be retained as rarely used and therefore expensive backup capacity.

The Need for Complementary Firm Power

Given the difficulty and low maturity of long-duration storage, clean firm power should be considered in all nations' complementary solution portfolios alongside long-term storage. As we have seen, long and severe supply gaps present a challenge that the most frequently discussed flexibility tools cannot solve alone. But neither long-duration storage nor clean firm power can be the single answer to this problem, because there are actually more similarities than differences.

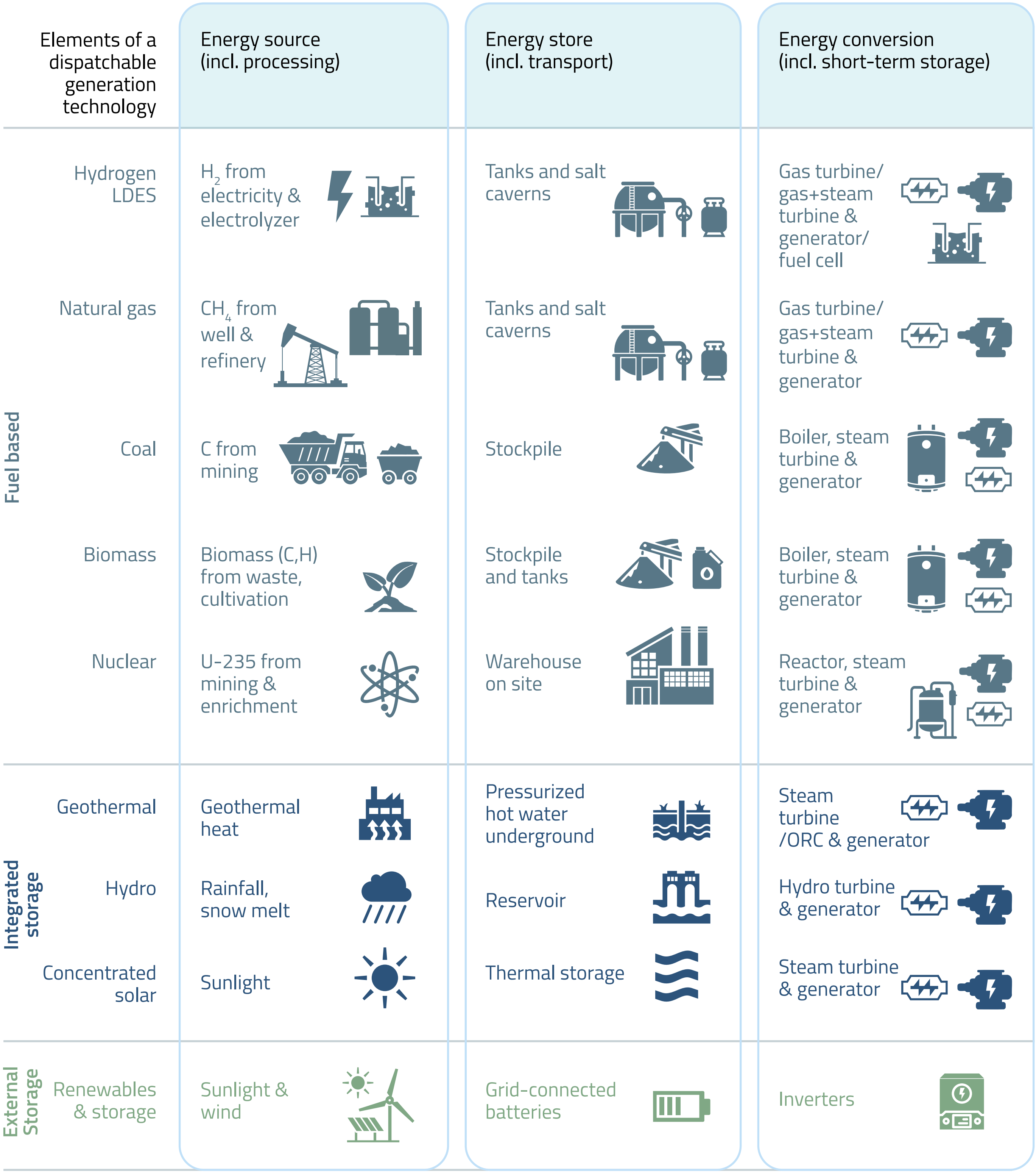
Proposed long-duration energy storage systems, such as hydrogen from electrolysis that is later used as fuel in an adapted gas power plant, often tackle shortfalls on the scale of weeks and months, similarly to the role envisaged for firm power technologies. However, one major distinction is that clean firm power technologies, such as geothermal or nuclear, are generally more mature than long-duration storage technologies. As we will argue below, this should make them a crucial part of any power system and innovation strategy.

The Economics of Covering Long and Severe Supply Gaps

Given that both storage and firm technology families aim to fulfill largely the same role, it is perhaps no surprise that they also share some key economic issues in doing so. To discuss and compare them within the same framework, in this report we conceptualize technologies in both categories by separating them into three elements:

- A source of energy, e.g. fossil fuels, nuclear fuel, solar heat, or grid electricity.
- A type of energy store, e.g. fuel tanks, water reservoirs, battery cells.
- A method of converting the stored energy to electricity, e.g. boilers and steam turbines, fuel cells, water turbines, i.e. the power plant itself in most cases.

A breakdown of the most common energy supply technologies according to these elements, including fossil, ultra-long-duration storage, and firm power technologies, can be found in Fig. 12.



	Elements of a dispatchable generation technology	Energy source (incl. processing)	Energy store (incl. transport)	Energy conversion (incl. short-term storage)
Fuel based	Hydrogen LDES	H_2 from electricity & electrolyzer	Tanks and salt caverns	Gas turbine/ gas+steam turbine & generator/ fuel cell
	Natural gas	CH_4 from well & refinery	Tanks and salt caverns	Gas turbine/ gas+steam turbine & generator
	Coal	C from mining	Stockpile	Boiler, steam turbine & generator
	Biomass	Biomass (C,H) from waste, cultivation	Stockpile and tanks	Boiler, steam turbine & generator
	Nuclear	U-235 from mining & enrichment	Warehouse on site	Reactor, steam turbine & generator
Integrated storage	Geothermal	Geothermal heat	Pressurized hot water underground	Steam turbine /ORC & generator
	Hydro	Rainfall, snow melt	Reservoir	Hydro turbine & generator
	Concentrated solar	Sunlight	Thermal storage	Steam turbine & generator
External Storage	Renewables & storage	Sunlight & wind	Grid-connected batteries	Inverters

Figure 12: Elements of dispatchable generation

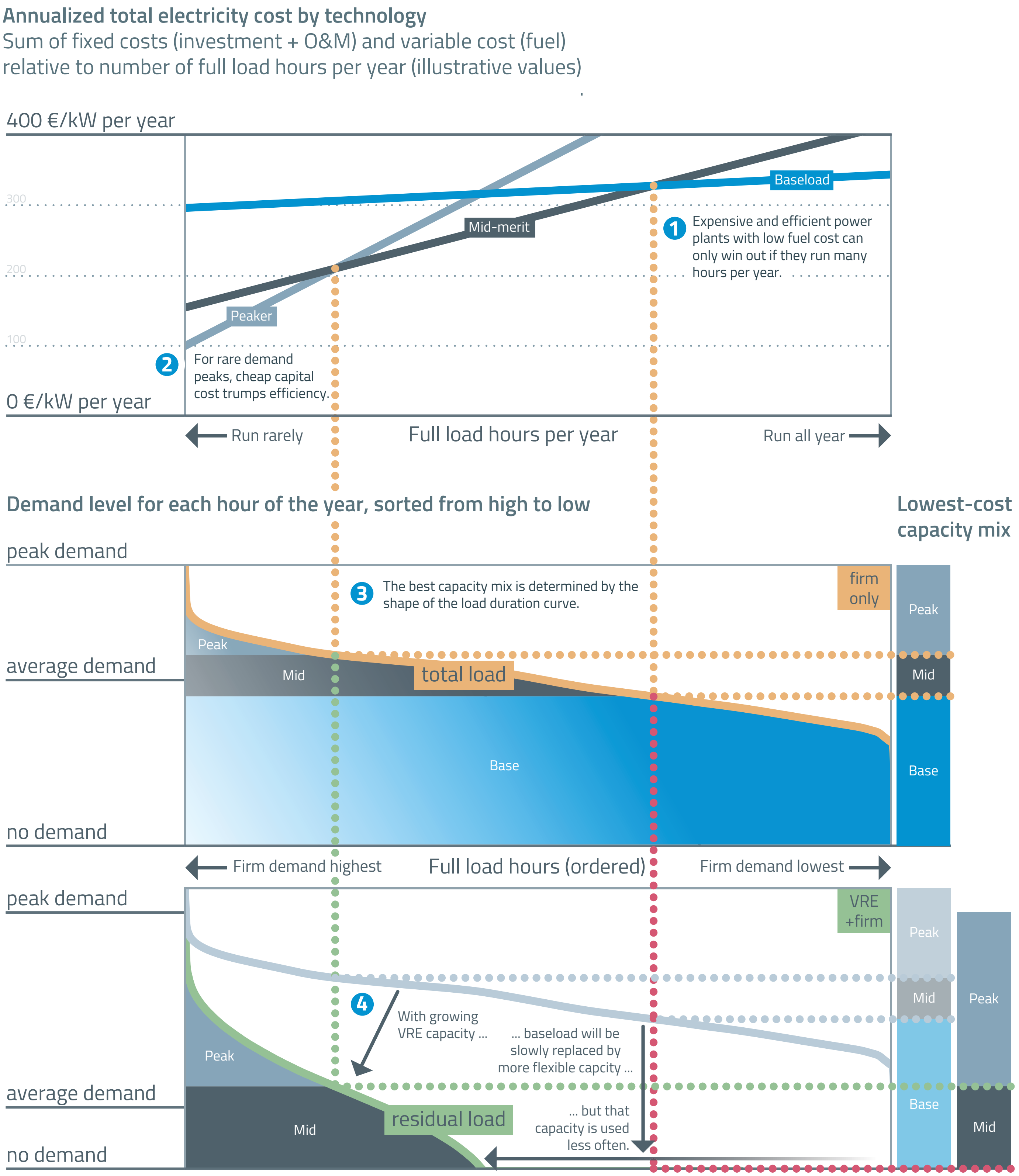
Economically, the challenge of covering relatively long and severe but infrequent gaps is the conflict between low utilization of assets and the large capacities of both power and energy they are required to provide.

The aspect of the *severity* of the shortfall makes the capital cost for the conversion element challenging. In the most extreme edge case, power capacity roughly equivalent to typical demand would need to be available. Low utilization results from the rarity of severe shortfalls, on the order of a few days per year (1 week out of 52 weeks equals about 2%) for shortfalls in which the residual demand is close to 100% of the average annual demand, and a few weeks per year for less severe shortfalls (1–3 months per year equals 8–25%).

The *duration* of a shortfall combined with its severity determines the energy storage capacity required, and therefore prolonged shortfalls incur challengingly high capital costs for the storage element. Compared to the energy a strongly renewable and battery-oriented power system could store in its fleet of batteries, the energy stored for a long supply shortfall would be many times larger (at least several days of average demand, compared to just a few hours' worth). As most of the capacity of these stores would be filled and emptied at most a few times per year, the same problem of low utilization arises as described for the conversion element.

Taken together, the severity and duration of shortfalls have two implications for technologies covering these gaps:

- Storage of fuels or energy needs to be extremely cheap, as there is no way around low utilization when covering rare events. This is no issue for natural gas, nuclear fuel, and reservoir water, but it is a significant issue for long-duration storage with hydrogen, due to its low volumetric energy density and other aspects.
- The power plants themselves, i.e. the energy conversion elements, must take part in other economic activities, likely day-to-day electricity generation, as they cannot be made cheap enough to economically allow for such infrequent utilization (see Figure 13). This is an issue especially for nuclear and likely for geothermal due to their high capital cost and is likely to increase levelized costs for all technologies that are losing market share to renewables and batteries.



① Expensive and efficient power plants with low fuel cost can only win out if they run many hours per year.

② For rare demand peaks, cheap capital cost trumps efficiency.

③ The best capacity mix is determined by the shape of the load duration curve.

④ With growing VRE capacity ... ... baseload will be slowly replaced by more flexible capcity ... ... but that capacity is used less often.

Figure 13: The different roles played by power technologies with different capital costs and running costs

Why a Diverse Innovation Portfolio Is Needed: Firm Power vs Hydrogen

It is hard to predict with any certainty how exactly energy systems across the world will develop. Still, the cost trends of renewables and batteries suggest they might displace other dispatchable technologies from the short-duration balancing roles (see Box 4 for a present-day example from California). This is certainly better than the most likely alternative, namely the continued frequent use of often expensive and always carbon-intensive fossil gas. But even in such a scenario with a significant displacement of gas, it would remain necessary to maintain an expensive fleet of backup plants that frequently cannot economically take part in day-to-day operations and are therefore mostly active during a Dunkelflaute. This expensive backup fleet may then offset a significant part of the economic benefit of renewables, i.e. electricity costs would remain high on average. The backup capacity would have to be almost as high as the typical demand, at least assuming that only a low level of demand reduction is achievable for several days of Dunkelflaute. This backup would be significantly larger than typical current flexible capacities but it would be used much less. Accordingly, to pay for fixed costs, electricity prices would have to be high during the infrequent occasions when the capacity is indeed used to a significant degree, or some form of expensive capacity mechanism would be employed to finance the backup.

Renewable Power Displacing Firm Fossil Power in California, USA

Box 4

Data from California, which has a very high penetration of renewables and especially solar, paints a picture of the competitive pressures dispatchable assets will face in many places [3]. Combined cycle plants are losing market share to renewables, which displace them mid-day, but they also lose revenue to more flexible fossil peakers. These less efficient but nimbler open-cycle gas peaker plants can cover the evening peaks better than them, while existing baseload nuclear or coal capacity has lower fuel cost and therefore covers the demand not supplied by renewables. This means that the type of plant that is hit worst economically, combined cycle plants, is precisely the one whose operational pattern aligns closest with renewables. But existing efficient baseload will also be increasingly displaced by renewables on the dispatch schedules of system operators. Accordingly, without capacity markets, there will be no business case for adding more of such expensive capacity, as it cannot be expected to run nearly 24/7 anymore. Notably, Californian hydropower has been much less affected and shifted its hours of production to complement renewables, producing more at night and less during the day. The ability to "get out of the way of renewables" with integrated storage is key for all types of complementary firm power (enabled by water reservoirs in the case of hydro). These dynamics are clearly visible on the example day shown in Figure 14.

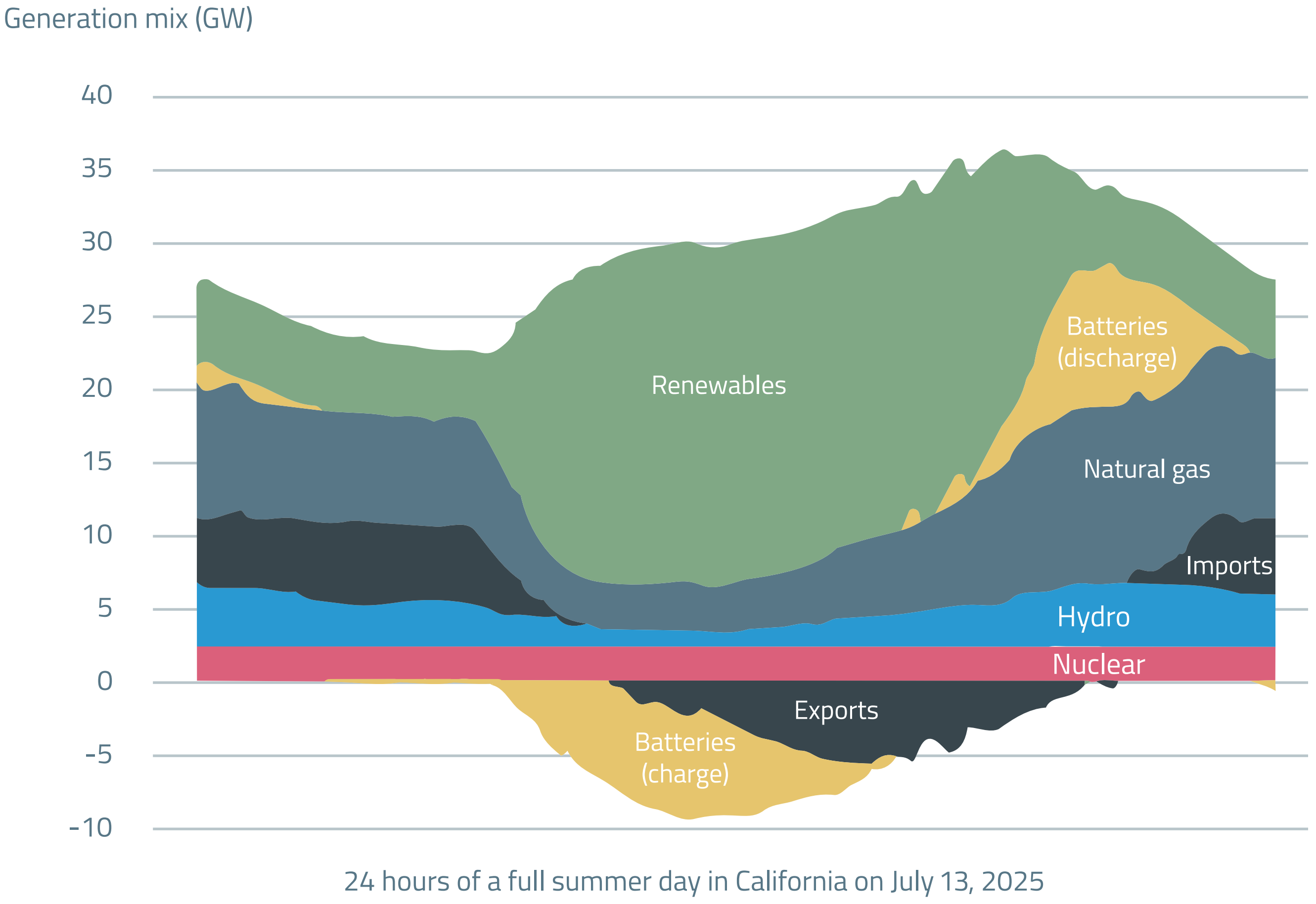


Figure 14: Example of a real summer day on the grid in California. Notice how solar supply dominates at noon and how batteries then play the same flexibility role as gas peaker plants in the evening.

To avoid such a scenario, we need new technologies that are complementary to renewables and to some degree competitive with batteries by fulfilling one or more of three criteria:

- Low or zero-cost energy source to have a chance of competing with zero-marginal-cost renewables or at least with natural gas.
- Low cost of power capacity for the element of the technology converting energy from the source into electricity to tolerate low capacity factors. For some technologies, a low effective cost of power capacity can be achieved through cheap generation-integrated short-term storage which maintains high utilization of the more expensive components (e.g. thermal storage in a nuclear reactor).
- Alternative revenue streams (e.g. daily arbitrage) to achieve a high capacity factor despite infrequent electricity generation.

We can see how these three criteria capture what is needed to economically cover supply gaps by applying them to the example of hydrogen, the most frequently discussed long-duration storage technology. This will also show that betting only on clean hydrogen is risky, and this is a key reason for why this report focuses on firm power technologies: Hydrogen is quite likely not the cheapest option to cover supply gaps, certainly not in all cases, and it may even be infeasible to beat natural gas this way. Alongside applying the criteria to hydrogen, we therefore must also consider how firm power technologies may fulfill them.

Low-Cost or Zero-Cost Energy

The energy used in a hydrogen-fired gas power plant is provided in the form of hydrogen made from electricity. It requires at least two conditions to be cheap, or at least to be as cheap as natural gas: very low electricity prices (to produce the hydrogen) and high capacity factors for the electrolyzers. Unfortunately, both conditions are to a large degree mutually exclusive.

An electrolyzer that only produces in the bottom ten percentile of price hours might pay very little for electricity on average (say 0–10 €/MWh), but its total output over the year would be too low to justify the capital investment. Conversely, if it ran most hours of the day, it would have to pay average electricity prices, which will be considerably higher than average natural gas prices for the foreseeable future. Accordingly, hydrogen would be uncompetitive with gas from electricity cost alone, and extremely uncompetitive when factoring in additional costs for transport and storage.

The most probable scenario for hydrogen being competitive with gas is an intermediate situation requiring two important developments: relatively frequent low-price hours through continued and intensified renewable deployment and cost decreases; and the development of very cheap electrolyzers to offset the likely still relatively low capacity factors entailed by operating during low-price hours (this is illustrated in Fig. 15). While not impossible, both are major challenges, with insufficient effort on one side raising the bar on the other.

By contrast, many firm power technologies have no trouble fulfilling the criterion of low- to zero-cost energy input (operating cost). Nuclear fuel rods require a complex supply chain, but they are very cheap compared to the amount of energy that they contain (5–10 USD/MWh [29]). Geothermal power plants receive a constant flow of free heat energy from the earth that requires at most a small amount of energy expenditure for pumping. Hydropower receives free renewable energy in the form of water inflows.[20]

A low-cost energy source also allows a technology to run more often, as prices need only rise a little over zero to be profitable in the merit order, as they will even in renewable-dominated systems. This in turn provides much-needed opportunities for revenue and enables higher utilization.

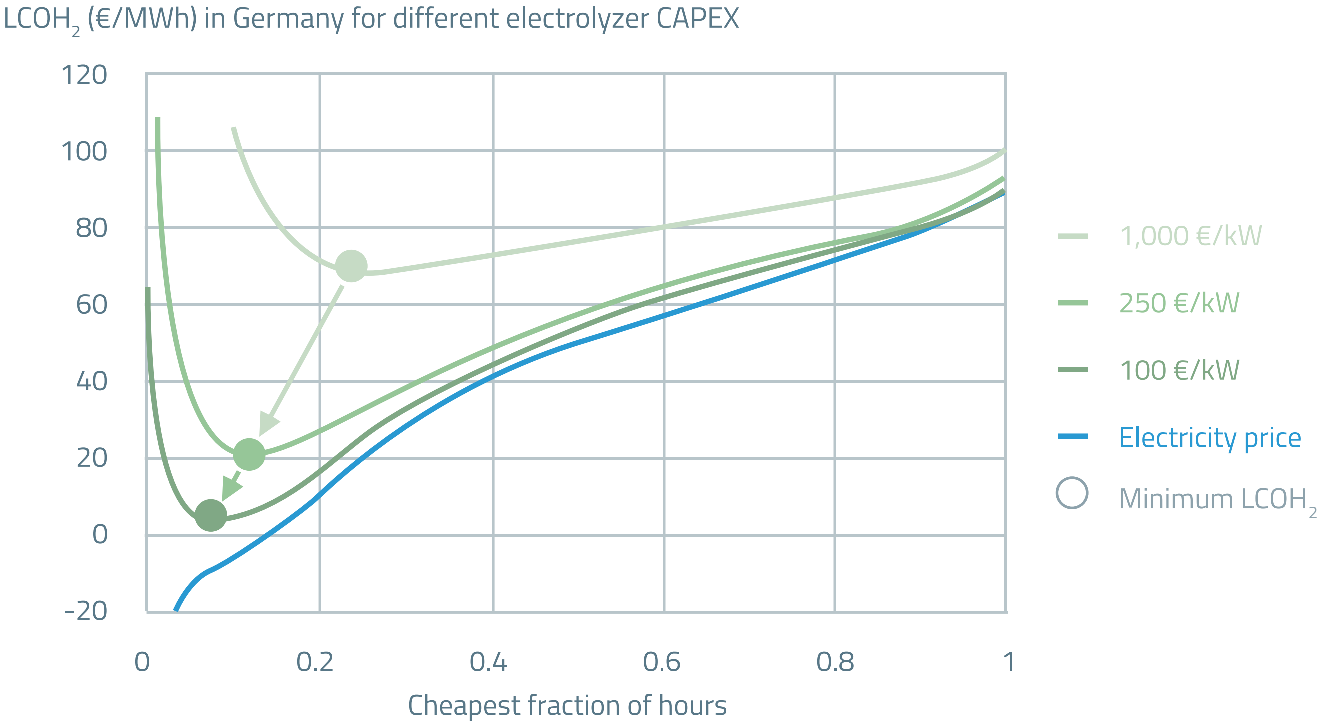


Figure 15: Levelized cost of hydrogen (LCOH$_2$) as a function of electrolyzer CAPEX and production at cheapest hours. Notice the tradeoff in targeting low-price hours vs utilization of the electrolyzer, resulting in a minimum; this minimum decreases with lower electrolyzer CAPEX, which enables more flexible operation during low-price hours. Price data from Germany July 2024 to June 2025.

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[20] Although these inflows are not constant and can vary considerably between seasons, standard reservoir storage usually provides a buffer, which is why hydropower is classified as "firm" despite the risk of being sometimes unavailable due to droughts.

Low Power Capacity Cost, Including Through Cheap Integrated Storage

Hydrogen power plants are very close cousins of conventional gas power plants, so much so that so-called “hydrogen-ready” gas power plants are being built in many places already, because the necessary design changes are relatively small. Accordingly, hydrogen as dispatchable generation technology almost perfectly fulfills the criterion of low capacity cost for the conversion element of the system, because open-cycle gas power plants have very low capacity costs. This is precisely the reason they serve as peaker plants.

But compared to conventional gas power, hydrogen still has the clear disadvantage that it is expensive to produce, transport, and store. As mentioned, the energy store element of a dispatchable generation system must be extremely cheap. In the case of gas, the capacity of the pipe network supplying it, as well as large-scale storage systems like engineered salt caverns, serve as a cheap energy store today. Superficially very similar systems are intended to serve the same role for hydrogen, but the required design adjustments to account for the physical and chemical nature of hydrogen are much more extensive than for power plants, and therefore much more expensive. In sum, these additional costs mean the energy cost advantage hydrogen needs to have versus gas must be even larger. Given that this difference is already very slim even under very favorable assumptions, hydrogen gas power plants could not rely on imports and would have to be located very close to production sites with favorable geologic storage opportunities, limiting the applicability of this solution even under favorable circumstances.

For firm power, a very cheap energy store is a typical feature of these technologies, e.g. nuclear fuel rod storage in a suitable warehouse on site, massive water reservoirs exploiting suitable geography, or geothermal heat contained in situ, i.e. underground. While this is clearly an advantage over hydrogen, virtually all forms of firm power feature higher costs for the energy conversion element – in some case dramatically higher, like for nuclear reactors supplying steam turbines. It is thus a challenge to achieve the low capital costs necessary to be able to afford the low capacity factor roles expected in renewable and battery-dominated systems.

As we will discuss in detail in the subsequent technology-specific chapters, a key solution may be cheap heat storage in many cases. Heat storage requires only simple materials and systems or is even an inherent part of the system in the case of geothermal, as plants can simply inject more fluid than they withdraw for a while, building up pressure and hot fluid in the system. Nuclear plants[21] are also inherently suited to thermal storage, as they do not turn their input energy directly into electricity: The conversion process first produces heat from nuclear reactions, and electricity is only produced in a second step from this heat with turbines and generators. By integrating heat storage as an additional buffer in the system, only the steam turbine and generator need to be sized to the desired peak power output, while other more expensive system components, namely the reactor core, can be smaller while running continuously to still achieve the necessary variable energy output over the year. This effectively reduces the levelized capacity cost and therefore lowers the minimum acceptable capacity factor.

Combining Revenue Streams

As pointed out in the beginning of this section, in order to justify the capital investments, generation assets need to provide more value than only covering the occasional Dunkelflaute. This is why taking part in day-to-day energy balancing is arguably an economic necessity for all dispatchable technologies. However, this need not be the case (at least in principle) if the assets can provide value outside periods of scarcity in other ways than producing electricity. These options are highly uncertain compared to selling electricity, yet such sector coupling may hold the key for the most economical way to cover renewable supply gaps (summarized graphically in Figure 16).

Here again, hydrogen provides an interesting comparison to measure storage and firm power against. One promising type of electrolyzer, high-temperature solid oxide electrolyzer cells (SOEC), can also operate in reverse to produce electricity as a fuel cell by consuming hydrogen. This puts them in the unique category of facilities that can both produce a valuable industrial product and also serve as a dispatchable power conversion element on the side [30]. Revisiting the dilemma of low prices vs high capacity factors previously discussed in the section on low-cost energy sources, we can see that the need for hydrogen to compete with gas as a fuel (i.e. purely on energy terms) is what makes this such a hard challenge for hydrogen. Selling hydrogen as valuable feedstock to industry instead might enable electrolyzers to command a higher price while staying competitive, since gray hydrogen made from natural gas is more expensive than the gas itself, as energy is lost in production and equipment is needed. Although the electrolytic hydrogen business case is far from today’s reality (gray hydrogen commands over 99% market share), it is a more feasible proposition than trying to compete with gas as a fuel rather than feedstock.

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[21] This is even more true for concentrated solar power plants, which already usually include thermal storage for higher dispatchability.

Again, we are interested in such a potential "non-electricity business case" in the context of dispatchable power because it could provide the bulk of the revenue required to support the smaller but vital side business case of covering renewable supply gaps. Specifically, if we compare such an electrolysis facility to a conventional gas power plant, we see that it gets the energy conversion element (the electrolyzer acting as a fuel cell) "for free," which is a massive advantage compared to the cost for a gas turbine and generator system. This advantage needs to be large enough to offset the disadvantages, though: higher fuel cost versus gas (opportunity cost of selling hydrogen to industry); higher hydrogen storage cost versus gas; and potentially higher capital cost and lower efficiency versus other electrolyzer technologies that lack the ability to efficiently operate in reverse.

So, while reversible electrolyzers may be a promising approach for hydrogen, there is significant uncertainty and the technology is not yet mature. Furthermore, the industrial demand for hydrogen in most regions would likely be covered by a total electrolyzer capacity that is insufficient to fully address covering supply gaps. Again, other options such as firm power technologies should be part of the portfolio, especially if similar "dual use" strategies can be developed for them. This seems especially feasible for concepts centered on industrial heat uses, adding to the case for integrated heat storage being a key part of the solution for making firm power work in a renewable-dominated system.

In contrast to the unique case of reversible fuel cells, firm thermal power technologies cannot get around the requirement of having a conversion element in the form of a steam turbine and generator. This means that a profitable industrial application of, for example, nuclear heat for a chemical process cannot simply switch its output from producing that chemical to producing electricity. To do so, turbines and generators would have to be added to the system, but those would be used too infrequently to be cheap. However, a plausible approach could be integrating industrial firm power with a separate thermal storage system known as a Carnot battery. In this concept, a thermal store is charged[22] to several hundred degrees with cheap surplus renewable grid electricity. Under typical conditions, the Carnot battery would act as a medium-duration energy storage complementing short-term battery storage, while the firm power system provides heat to the co-located industrial process. In a period of scarcity, the firm power heat production is used to charge the heat storage of the Carnot battery instead of providing heat to the industrial process, which is paused until the value of stored heat for electricity production drops again once the period of scarcity ends.[23] In this way, all components of the system would be in frequent use, resulting in low levelized cost per unit of electricity and industrial output.

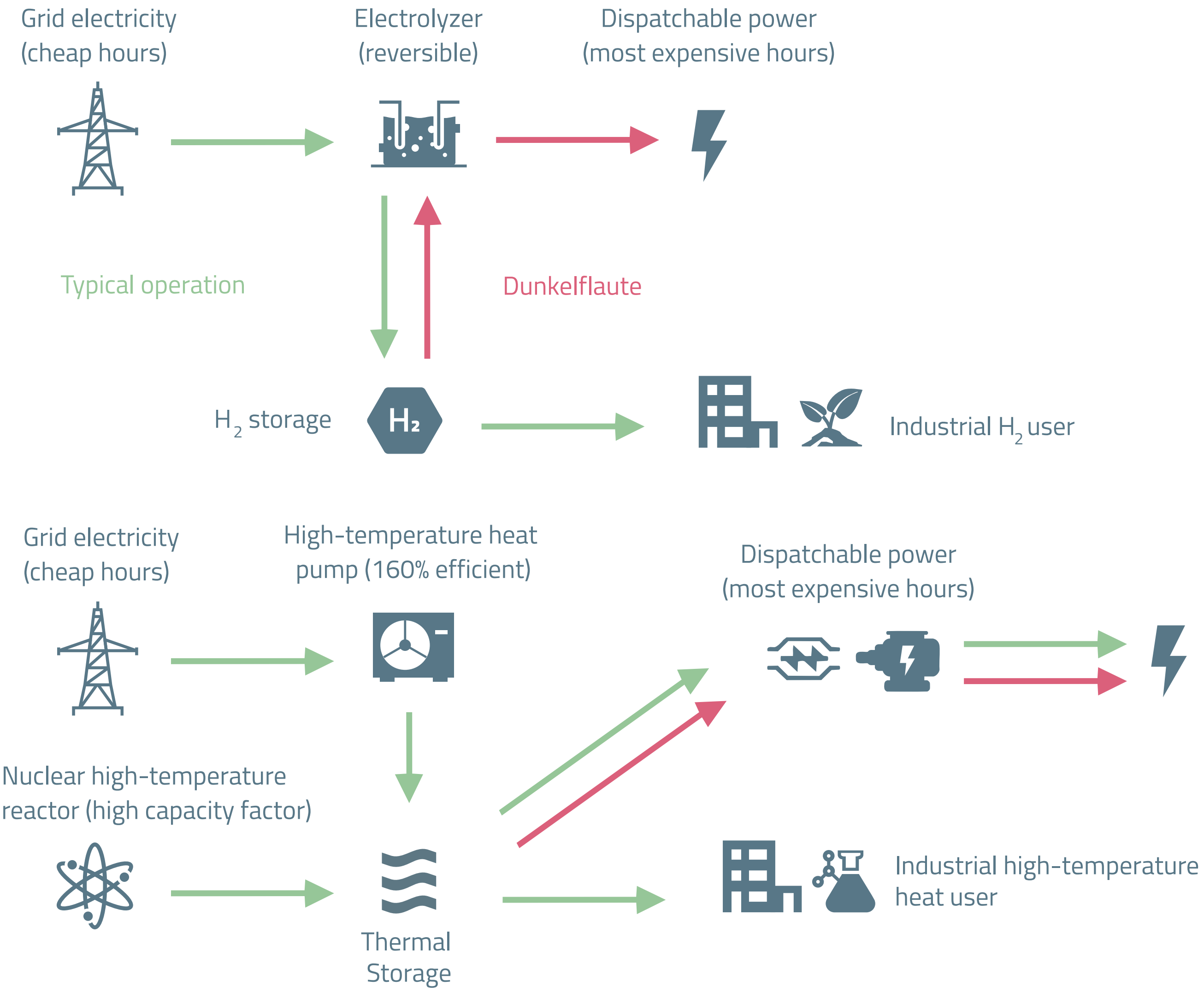

Figure 16: Examples of dual-use scenarios to prop up the business case of clean firm power

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[22] The charging phase can be done in various ways, including with high-temperature heat pumps to boost the efficiency.

[23] In general, such approaches are conceptually quite similar to demand management, as they involve stopping an industrial process for a short time, reducing the capacity factor of the industrial facility by a few percentage points. The key difference is that firm heating power is generally significantly cheaper than providing the same heat with electricity, and the loss in industrial output from "heat-load dropping" would be covered by additional income from selling electricity during a high-price period.

Every Dispatchable Option Matters: Expected Benefits of Diversification

Modeling future energy systems is an essential tool to attempt to understand the complex interactions between various energy sources at the system level and determine "optimal" mixes. This is a very difficult exercise, with many assumptions[24] and compounding uncertainties; as such, these models should not be treated as accurate predictions, but rather interpreted as a way to compare various energy scenarios and assess fundamental trends that emerge. Several academic studies have modeled power grids with variable renewables plus clean firm power and find notable benefits to this portfolio approach.

In the case of nuclear, Jenkins et al. find that flexible operation that complements renewables can lower overall power system operating costs and reduce renewable curtailment while also increasing the profitability of nuclear plants[25]. Although the exact numbers would be specific to each region, these conclusions likely hold for power systems with sufficient levels of both nuclear and variable renewables (>25% and >20% respectively) [31]. A subsequent section of this report gives more technical detail as to how nuclear plants can be operated flexibly.

In the case of geothermal, Ricks et al. find that, for a range of market scenarios in the United States, total annual costs of fully decarbonized systems are lower when geothermal is included in the mix, and even more so when geothermal is operated flexibly,[26] shifting generation on diurnal and seasonal timescales [32].

The dispatchable generation technologies covered further down in this report draw from different energy sources and as such have different strengths and drawbacks. Nevertheless, they are conceptually similar, especially in their common mission of beating natural gas plants as the tool of choice for economically providing much-needed flexibility in clean power systems. There is no clear favorite as to which technology is best placed to succeed in this mission, although some likely dead ends can be identified and disregarded. Accordingly, if we are to find solutions suitable for all economic, climatic, and geopolitical situations, it is wise to pursue a portfolio of technology bets, including those that build on mature existing firm power technologies.

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[24] For a given region of study, the assumptions of an energy model will include parameters such as: the share of each source in the energy mix and its evolution over the coming decades; future weather patterns over many years; future prices of commodities and technologies; changing demand patterns; and interconnections to neighboring grids.

[25] In the case study by Jenkins et al., the profitability of the nuclear plants increases thanks to revenues from reserve provision, reduced exposure to negative prices, and lower variable operation and maintenance costs of the plant.

[26] Whether through load-following or in-reservoir energy storage; these are detailed in a subsequent section.

Technologies Out of Scope

The terms "clean firm" or "clean dispatchable" power can be taken to include several net-zero emissions technologies, frequently including fossil generation with carbon capture and storage (CCS) and bioenergy.[27] In the following sections, we will briefly outline why we do not focus on these technologies in this report; it essentially comes down to unfavorable economics.

Carbon Capture and Storage

The exhaust gas of fossil fuel combustion processes contains carbon dioxide (CO_2). The goal of carbon capture is to separate a part or all of this CO_2 before it enters the atmosphere. If the captured CO_2 is subsequently stored permanently, for example underground, it does not contribute to climate change, meaning the energy produced from combustion can in principle be deemed carbon-free.[28] Various chemical and physical techniques exist to remove CO_2 from exhaust gas streams and, as a general rule of thumb, these techniques are more energy efficient the more concentrated the CO_2 is in the gas to be treated.[29] These technologies are very mature as they have been in use in refineries, natural gas liquefaction facilities, and other chemical plants for many decades. However, these applications are not aimed at the abatement of significant process emissions, but rather driven by downstream technical requirements, mainly to achieve a certain purity of the output, e.g. 2% CO_2 content for pipeline-quality natural gas. The resulting concentrated CO_2 is usually vented or sometimes used in products that typically release CO_2 at a later point, for example urea-based fertilizer.

For the purpose of electricity generation, however, there is a fundamental and insurmountable economic barrier that will prevent CCS from ever achieving cost-effectiveness: It cannot compete with unabated fossil generation, as it is always more expensive, both in terms of CAPEX – for capture, transport, and storage equipment – as well as in terms of operational expenditure (OPEX) – increased energy use and maintenance. This fact is independent of technological development, as the capture cost cannot be reduced to zero and will likely always remain significant, and any cost reductions on the generation side will equally apply to plants with and without CCS (see Fig. 17).

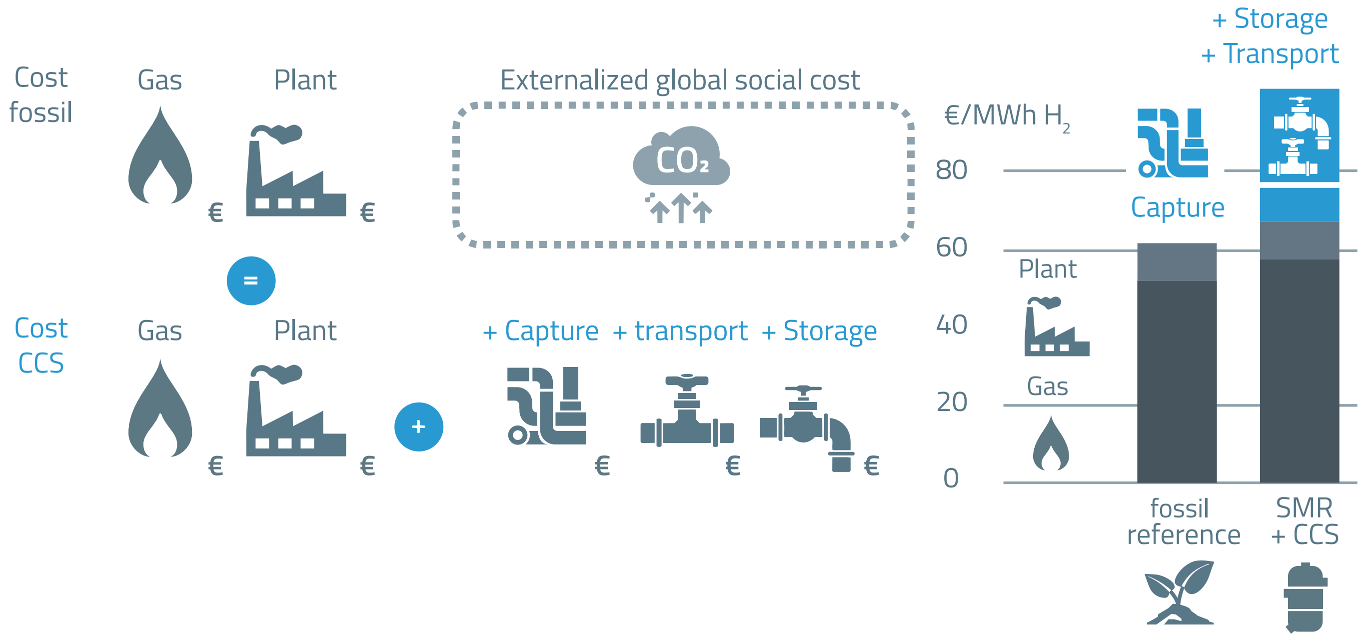

Figure 17: Comparison of hydrogen production by steam methane reforming (SMR), with and without carbon capture and storage (CCS)

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[27] Concentrated solar power (CSP) could also arguably count among clean firm power technologies, because integrated thermal storage (standard practice in the sector) makes CSP dispatchable nearly 24/7. However, it is affected by seasonal variability of the solar resource, so it is not a completely "firm" energy source; the concept of "clean firm power" is more of a spectrum than a binary. Moreover, CSP with thermal energy storage (TES) competes directly against photovoltaic with battery storage, so the comparative advantage is less clear-cut.

[28] There are, however, significant emissions associated with methane leaking upstream in the supply chains of natural gas and fossil fuels. These emissions are often of a comparable magnitude to those from combustion and are not solved by CCS.

[29] The concentration of CO_2 in the atmosphere is much lower compared to that found in exhaust gases, which makes it much harder to extract CO_2 directly from the atmosphere. This is why one generally uses the term "carbon dioxide removal" (CDR) to refer to capture from the atmosphere, and CCS to refer to capture from concentrated point sources.

Hypothetically, in a world where a global carbon price is agreed upon and effectively enforced in large parts of the world economy, CCS could have a chance to compete with unabated fossil generation and other clean firm power technologies. The technology would not diffuse beyond the jurisdictions where the carbon price is collected, though.[30] Outside of the territory of such a coalition, it is likely that most economies would be poorer and therefore probably be unable to develop a cheaper clean alternative to fossil energy down the line. Predicting geopolitical developments is difficult, but such a widely applicable carbon price seems unlikely to come to pass soon; there are even instances of countries backtracking on carbon pricing, such as Italy's Energy Decree, which will reimburse gas-fired power plants for the cost of carbon permits incurred by the EU's Emissions Trading System (ETS) [33]. By contrast, in the current political climate, energy security and independence are more important than ever, and they are not served by CCS.

Nonetheless, countries may still decide to permanently subsidize CCS instead of investing in new clean firm power technologies and betting on sufficiently rapid price decreases, as happened in wind and solar,[31] (or do both in parallel). After all, with the ETS there is already a functioning carbon pricing system in effect in the EU providing a much-needed edge for incumbent carbon-neutral technologies. However, contrary to strengthening the case for CCS, the existence of successful local carbon pricing regimes actually underlines the fundamental economic flaws of the technology, as electricity generation with CCS is still virtually nonexistent. Despite carbon pricing and other incentives, CCS projects exhibited a high failure rate from 1972 to 2017: 98% of coal power projects, 100% of gas power projects, 100% of waste energy projects, and 100% of bioenergy projects [34]. Despite decades of experience with CCS technologies at scale and corresponding cost decreases, they are still too high to make economic sense even when subsidized.

Adding to these economic concerns the problems of energy dependence, particulate emissions and associated health concerns, and CO_2 storage and transport infrastructure needs, it becomes clear that firm fossil power with CCS is a short-sighted option for any economy that siphons away public support from actual solutions. Nonetheless, there will be a political tension between continued emissions and the potentially substantial delay until a scalable long-term solution can be deployed at scale. This may be defused if public discussion converges on the consensus that CCS cannot be economic and delaying innovation to pay for stopgap measures is not a worthwhile trade-off.

Finally, any economic appeal of fossil-based sources of firm power rests in part on implicit assumptions that will be eroded in the medium to long term by the energy transition. Namely, fossil fuel supply chains are complex pieces of physical infrastructure; it is only their massive scale and consumer base that justifies viable investment in these assets. In a world where fossil fuels are being phased out across all sectors, the user base for these assets will shrink, but the supply network (such as natural gas pipelines) will not diminish proportionally, resulting in progressively higher costs for the remaining consumers.[32] It is possible that below a so-called "minimum viable scale" [35], these fossil fuels will no longer be economic at all and supply will collapse non-linearly. Consequently, historically low prices of natural gas power generation (at least relative to today's state of clean firm power technologies and long-duration energy storage) might be a mirage that does not translate into economic viability for the niche role of natural gas as a backup option during Dunkelflaute.

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[30] Contrary to technology for abating locally acting pollution, which has successfully spread globally. These are associated with regulation concerning pollutants like sulfur dioxide (causing acid rain) and particulates (causing respiratory diseases and heart failure, as well as smog). The difference versus GHGs lies in the global nature of the damage caused by climate change, which spreads the benefits of mitigation efforts among all (the so-called "free-rider problem").

[31] One argument for such a strategy is that it would be a stopgap measure to reduce emissions until a cheaper clean solution is available at scale. While this is possible in principle and an evaluation depends on many details, it is generally unlikely to be beneficial in terms of emissions avoided and for the development of a national economy. The significant required funding to pay for CCS and the associated long-lived infrastructure presents an opportunity cost of investing in innovation and scale-up efforts of clean technologies. This is bound to slow down these efforts and the diffusion of the technologies compared to not investing in CCS. Given the global effect a cheap clean technology can have once it becomes established at scale, delaying this diffusion process means locking in significant carbon emissions – almost certainly more emissions than can be avoided by the CCS measures paid for by accepting the delay. Furthermore, such a strategy means the country will end up owning stranded assets instead of hosting modern clean technology industries.

[32] This phenomenon is also known as the "utility death spiral."

Bioenergy

The combustion of wood and other materials of biological origin – generally referred to as biomass – to generate heat represents one of the earliest forms of human energy use. Biomass refers mainly to plant materials, but can also include animal-based materials, both of which are composed mainly of carbon and hydrogen, with some amount of oxygen, nitrogen, and other trace elements. Fossil fuels contain mostly carbon and hydrogen as well, as they are derived from ancient plant matter which was changed by geological processes that turned it into crude oil, natural gas, coal, or related substances (hence the name "fossil" fuel). Similarly, biomass can be treated in various ways such as in biorefineries or through the action of microorganisms to yield refined fuels (e.g. ethanol). Roughly speaking, biomass and biofuels are chemically very similar to fossil fuels, although the specific energy content varies based on the type of biomass. For example, moist sewage sludge's energy content is much lower than fossil fuels, and vegetable oils are just as high as crude oil. Accordingly, they can be used in almost the same way; for example, a gas power plant may run on biomethane instead of fossil methane, without any changes.

The key difference between fossil fuels and biogenic fuels is of course their production. Every carbon atom present in a biogenic fuel was taken out of the atmosphere by the plant when it grew via photosynthesis powered by sunlight, so the CO_2 emitted by burning that biogenic fuel for energy has already been offset by the carbon captured by the plant during its growth. In theory, this results in net-zero carbon emissions; in practice, however, multiple factors may result in biogenic fuels still causing net emissions, sometimes even more than the corresponding fossil fuels [36]. Among others, these factors include: the use of fertilizer to produce the biomass (both the fossil fuel to produce the fertilizer and, after its use, the formation of N_2O, a potent GHG, from any fertilizer not taken up by plants); energy use in production, such as fuel for heavy agricultural machinery; and methane leakage[33] at any point in the supply chain. Of course, for each of these factors, the impact can be mitigated by appropriate measures such as clean hydrogen for fertilizer, electrification of machinery, and strict monitoring of methane leaks. In some cases, the production of bioenergy is even beneficial for the climate, by addressing a waste product that would have otherwise rotted in landfill and released methane to the atmosphere. Nevertheless, the net result of all these complex factors is that the lifecycle emissions of biomethane production span a wide range[34] from 0.1–483 gCO_2eq/MJ_{HHV} depending on the facility; the average lies around 52 gCO_2eq/MJ_{HHV} and the distribution is skewed toward the top 5% of emitters representing over 60% of total emissions [37]. By comparison, the combustion of methane (excluding leaks in the natural gas supply chain) produces around 50 gCO2eq/MJ_{HHV}, i.e. a similar level. Bioenergy's status as a clean energy source is thus deeply contingent on enforcing highly demanding standards on its supply chain; it therefore presents a serious risk of failing to actually deliver genuinely clean energy.

Beyond the tenuous climate credentials of bioenergy, two further critical impediments remain, which are essentially insurmountable: cost and limited potential for scaling up supply. In the case of biomethane, its production is much more expensive than natural gas: Even at the largest scale and using waste streams with negative costs (i.e. the producer is paid to take care of the waste), biomethane production by anaerobic digestion (the most prevalent pathway) costs 60–130 €/MWh in the EU [38], a benchmark that even the permanently elevated gas prices since Russia's attack on Ukraine only rarely reach for short times.[35] The situation is unlikely to improve: Most aspects of bioenergy production are mature without prospects for transformative breakthroughs,[36] especially in agriculture, where after rapid progress in the second half of the 20th century, yield improvements have slowed significantly [40]. Bioenergy's presence in the market despite its lack of economic competitiveness is only through substantial subsidies and beneficial regulation (e.g. certificate trading and quotas). Expanding it further would probably mean further decreasing cost-effectiveness, since the cheapest feedstocks (agricultural residues, manure, other plant by-products) are already being exploited [38].

Still, as with CCS, there are and will be countries that prefer a strategy of continuous subsidization[37]: A clear benefit of bioenergy is that it is always domestically available, providing some measure of strategic energy security; many nations subsidize local food production for similar reasons. However, the second challenge at the heart of bioenergy is insufficient potential for increasing production due to limited feedstock relative to all the possible sources of demand. Biomethane and biogas currently supply only 230 TWh, i.e. 6% of European gas consumption [38]. While Europe does have scope for increasing production, with upper estimates reaching around 2,600 TWh[38] with maximalist policies [41], this still falls far short of the current 3,500 TWh of natural gas consumption and 16,000 TWh of primary energy consumption [42]. Consequently, bioenergy must be treated as a scarce and precious resource that must be allocated to priority sectors, which is not the case currently: In 2024 in Europe, 18% of biomethane went to buildings (i.e. low-temperature heat), 25% to transport (including road), 15% to power, and 14% to industry (including low-temperature) [38]. Analogously with the so-called "hydrogen ladder" popularized by Michael Liebreich and others, which identifies the most cost-effective uses of hydrogen, there should be a "bioenergy ladder" whereby certain sectors (namely clean fuels for aviation, shipping, high-temperature heat, and Dunkelflaute backup power generation[39]) need bioenergy more than sectors that have more plentiful alternatives. For example, domestic heating should be decarbonized by heat pumps rather than biogas. Even with this prioritization, however, the demand for clean energy outstrips bioenergy's supply potential, which is why other solutions are necessary.

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[33] Also known as fugitive emissions.

[34] Such wide ranges introduce a high degree of uncertainty, which impedes clear and sound policy decisions.

[35] In 2025, the average TTF price for natural gas (the benchmark for European wholesale gas) was 38 €/MWh.

[36] On a fundamental level, the low efficiency of photosynthesis indicates that even more speculative bioenergy solutions like algae-based fuels have limited potential. It is typically around 2%, which compares unfavorably to modern solar photovoltaic panels with an efficiency of over 20% [39].

[37] Again, at the cost of slower innovation and the chance to benefit from technological leadership, see the section on CCS above.

[38] This assumes collecting 60% of agricultural residues and virtually all livestock manure (673 TWh), universally intensifying grazing to free up land for bioenergy production (1,178 TWh), and a large-scale shift in dietary habits toward a healthier (low-meat) diet (774 TWh), bringing the upper estimate to 2,625 TWh.

[39] It is already standard practice for countries to maintain strategic reserves of oil and gas in case of disruption. This policy could be easily adapted to setting aside clean biomethane that can serve exclusively for power generation during Dunkelflaute (as opposed to day-to-day electricity supply, where wind and solar will be more competitive).

Hydropower

Hydropower (hydro) is one of the oldest forms of energy conversion used by humans. For centuries, the movement of water has been used to do mechanical work on a large scale, like milling grain or driving machinery. In modern times, it is almost exclusively used to generate electricity. In 2025, hydro accounted for 330 TWh of electricity production in the EU and has been stagnating at this level for decades. This contrasts with the rapid expansion of production from wind and solar, which respectively grew from 21 TWh and 0.05 TWh in 2000 to 473 TWh and 368 TWh in 2025. Accordingly, hydro is no longer the largest renewable electricity source; it represented 12% of the near 2,800 TWh of total EU27 electricity production 2025 [43]. Within Europe but outside the EU, Switzerland relies heavily on hydropower, producing 30–40 TWh depending on the year (over half its electricity mix), as does Norway with an annual production around 140 TWh (90% of its electricity mix) [43].

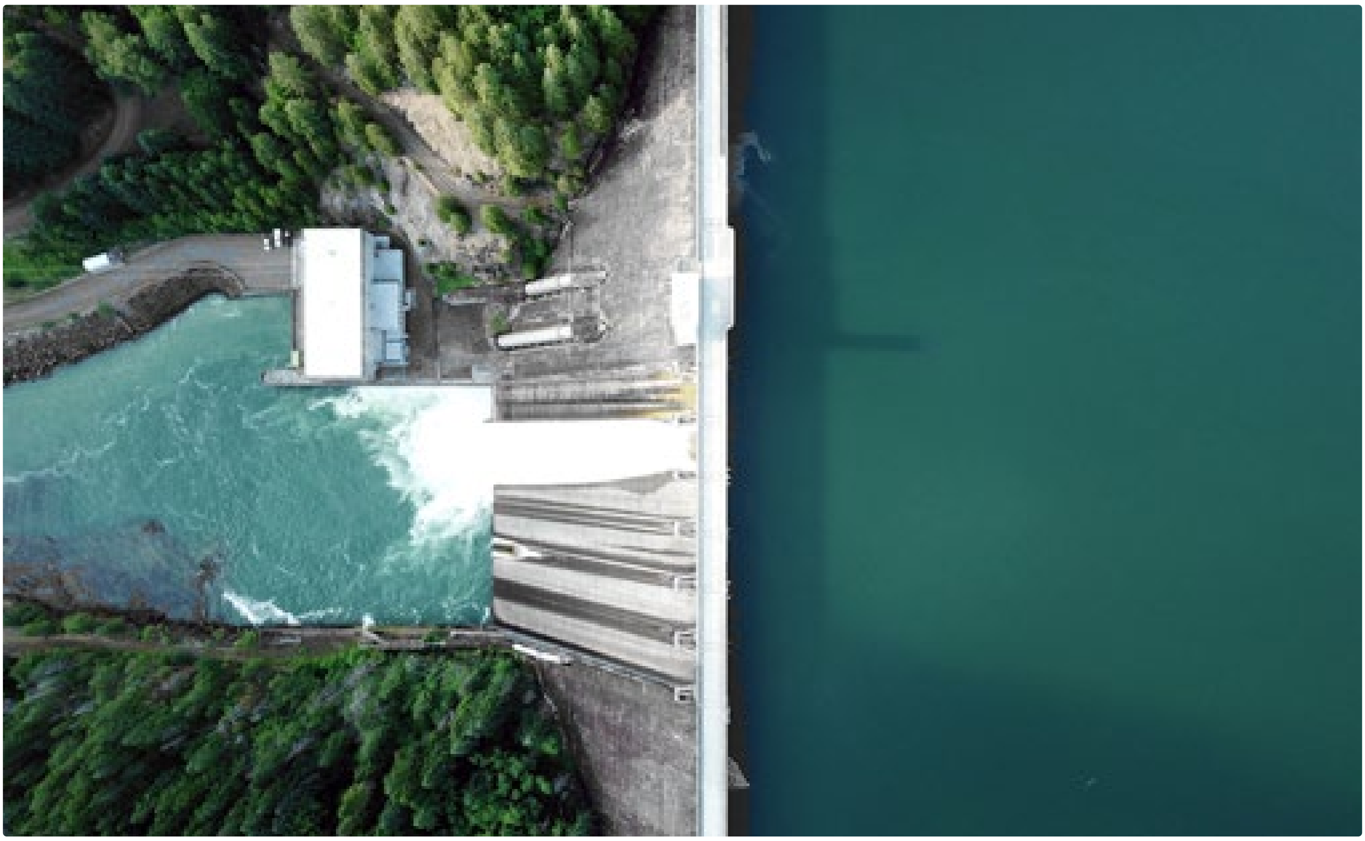
Conventional and Innovative Hydro

Technologically speaking, hydroelectric power generation involves converting the kinetic energy of moving water into electricity with turbines and a generator.[40] Many rivers move fast enough to enable at least some electricity generation from the kinetic energy of the flow alone; however, most hydroelectric generation is based on artificially changing the flow of water in one location with dams to make it more suitable for energy harvesting. With a dam, engineers can create the conditions for fast-flowing water via a difference in elevation between the inlet and the turbine (called "head"). In most cases, dams are taller than this difference, so that they also serve as a reservoir, storing water above the turbine inlet and thus rendering the power plant dispatchable.

Based on these general physical principles, hydro generation types can be seen as a continuum: from dams with very large reservoirs that can spend substantial time periods accumulating water, to micro-turbines that have no dam or reservoir associated with them at all and simply extract energy from the flow of the river whenever the river carries enough water. In between, there are run-of-river hydro plants that operate on a substantial elevation difference but with little or no reservoir. Moreover, when the terrain is suitable, pumps may be employed to fill reservoirs at higher elevation, essentially storing electric energy as potential energy for later use. This can be integrated with a dam system at a river but may also be located completely off-river in a closed loop. In such pumped-hydro storage plants, the turbines and generators are designed to be able to function in reverse, acting as pumps. This is fairly efficient in both energy terms (~80% round trip efficiency) and in capital utilization terms (since 50–70% of the total installed cost of a hydropower plant with reservoir storage is the civil works[41] [2]); historically, pumped hydro has constituted the bulk of grid-scale electricity storage globally.

Cost

The cost of electricity from hydro varies significantly based on the project. Since there are no variable costs for fuel, the expenses for hydro plants are almost entirely concentrated at the beginning of the lifetime during construction. Hydropower potential is strongly site-dependent, and the suitability of the site has an equally strong influence on the cost per kilowatt, which can range from 500–5,000 €/kW [44], although sites actually chosen for development fall within a narrower range. For comparison, large gas turbine plants have capital costs on the order of 1,000 USD/kW$_e$ [45].



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[40] Some concepts that are sometimes mentioned under the heading of hydroelectricity work on different principles, e.g. saline gradient and ocean thermal power, but these concepts are relatively immature and face even more limited potential than more conventional hydro, which is why they are not the focus of this report. Similarly, due to the limited potential of tidal power, which relies on relatively rare geographic conditions that channel the flow of the tides, it is also not discussed here. Wave power may have a somewhat larger albeit still limited potential, but it is not a firm power source, so it is out of scope as well.

[41] A reversible pump-turbine system for pumped storage hydro is more expensive than a one-way turbine, but the difference is small compared to the overall system cost.

In terms of average LCOE, hydro has historically been relatively cheap, including more recent projects in regions of the world with little exploited hydro potential so far. Over the last decades, China undertook massive hydropower expansion projects, which resulted in reported costs averaging around 1,000 €/kW, or an LCOE of around 20 €/MWh, about two-thirds of the LCOE[42] of wind and solar photovoltaic in 2024. Europe's potential is largely exploited by now, and social and political conditions are less conducive to expansion than in the 20th century, so few projects have been completed recently. In 2018, the LCOE for most projects was in the range of 44–140 €/MWh, with the majority below 100 €/MWh [46]. The global average was about 60 €/MWh in 2023 [47].

However, it is important to see these numbers in the context in which hydropower has been developed, or will be developed in the future, particularly in Europe. As already mentioned above and discussed later below, the cost of hydro rises relatively quickly once the best sites are exploited, so future expansion of hydro will face progressively higher development costs in Europe. At the same time, even where hydro resources are less exploited and ready for development, other renewables may become the better option as they are still getting cheaper [2].

Revenue certainty is nearly indispensable for most large-scale hydro power projects; the sheer size of the plant means its construction falls into the category of "megaprojects," where lead times are long and financing costs are critical, which makes these projects less amenable to private investment. Hydro projects are therefore almost always developed with very long-term power purchase agreements or state guarantees in place [48] and it is often the public sector itself that undertakes the project, so that it can also deliver non-energy-related benefits like water management and flood control. Furthermore, mobilizing political will at this scale, not least for managing environmental tradeoffs of ecosystem disruption and societal tradeoffs of the displacement of populations, carries a large non-monetary cost that is not reflected in the LCOE. These tradeoffs are also a highly relevant factor in smaller projects and play a large role in determining the remaining potential for hydropower, as discussed below.

Project execution also plays a big role in determining costs, especially for larger dams, as megaprojects are inherently at risk of schedule and budget overruns. In one study of a large set of large dams, the average cost overrun was found to be 96%, dominated by a long tail of projects that were completed severely over budget and behind schedule [49]. Investment in these projects would likely not have gone ahead if those risks had been accurately foreseen during planning. Despite this, when considering advantages beyond electricity generation, dams also provide a strategic opportunity to exercise geopolitical power by controlling the amount of water that is let downstream, which can play a role in government backing of these projects [50].

In summary, the wide range of site conditions prohibits blanket statements about hydropower's viability to contribute to the global energy transition and individual countries' economies. Where conditions are good, the resulting LCOE can make hydro the cheapest energy available, with essentially zero emissions[43] [44] and at large scale, as well as providing co-benefits like flood control or water management. Even though the costs can be substantial in terms of sociopolitical coordination and environmental damage due to flooding, the benefits in locations where unexploited potential still remains can be worthwhile.

Prospects for Innovation

Site characteristics are one of the most important factors affecting a hydropower plant's design and overall viability. They drive a range of social, environmental, and economic considerations, meaning that both well-suited and less well-suited sites feature many tradeoffs. Directly improving hydropower technology itself would therefore be worthwhile to expand capacity with fewer tradeoffs, but hydropower is unfortunately a very mature technology, so few prospects for significantly lowering costs or increasing efficiency remain.

Nonetheless, modernization and upgrading present an opportunity for adding a certain amount of flexible firm power or making it more useful at reasonable cost. This is especially true for aging hydro plant fleets like those in Europe, where the average age is 45 years. One particularly low-cost example is retrofitting plants with optimized digital control systems. For example, this could enable lower minimum loads, increasing the plants' flexibility range and thereby making them more complementary to variable renewables. Similar and expanded benefits can be achieved by replacing aging turbines and pumps in pumped storage plants with more flexible modern equipment. Adding on-site battery storage can also be helpful in this regard and extend the life of turbines by allowing them to run at a more constant speed while still providing ancillary services like frequency control [51]. More importantly, improved efficiency of modern equipment can add about 10% additional capacity at relatively low cost, especially when refurbishment is required due to the age of the installation. In addition, there is likely some marginal potential for retrofitting power generation equipment to existing dams that are currently devoid of any power generation, though in many cases the non-energy services these dams provide could impact the economic viability of such retrofits [52].

Risks Associated with Hydro

Box 5

Modern hydro plants with large dams are extremely safe, with death rates from accidents and pollution (normalized per TWh of produced electricity) 20 times lower than coal, which is much more harmful due to the associated particulate emissions causing damage to lungs and hearts as well as other illnesses. Deaths associated with hydropower come from rare cases of dam failures or other events causing massive and sudden flooding, such as landslides into the reservoir. Since 1969, there has been only one case in OECD countries involving a dam failure, which caused 14 deaths, and failures have become significantly rarer in the last 25 years globally, involving just 0.12% of dams built after 2000 [53][54].

However, there have been mass casualty events further in the past. In Europe, 423 deaths resulted from a structural failure of the Malpasset Dam in France in 1959, and about 2,000 were killed when a landslide hit the reservoir of the Vajont Dam in Italy in 1963, causing a tsunami to flood the valley below. A very recent disaster occurred in 2023 in Libya, where the collapse of two dams killed between 7,800 and 24,000, likely making it the second deadliest dam collapse in history. The worst accident in the history of hydropower was the failure of the Banqiao Dam and associated dams in 1975 in China. Several tens of thousands of deaths resulted from the flooding directly, while in the aftermath epidemics and malnutrition brought the death toll to 140,000–240,000. This case also illustrates that dysfunctional government structures tend to play a large role in such disasters, with the presence of hydropower infrastructure being just one enabling factor in the chain of events, albeit a very visible one compared to more diffuse but more harmful factors like air pollution.

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[42] Hydro's cost advantage is actually understated here, since LCOE does not include the value of firm power, equivalent to the cost of balancing for intermittent technologies.

[43] Hydropower has a low median emissions intensity of 24 gCO_2eq/kWh, with roughly a third resulting from construction and the rest largely from methane emissions resulting from flooded decaying organic matter in the reservoir.

Flexibility

Hydropower is considered a firm power technology due to the buffering capacity inherent in the large amounts of water contained in streams, rivers, and especially reservoirs. Water is supplied naturally through the Earth's hydrological cycle of evaporation and precipitation.[44] Because of the buffer of water available in the reservoir, it makes sense to design turbines for a flow rate larger than the average reservoir inflow. Accumulated water can thus be discharged at a higher rate, drawing down the reservoir level and making hydro a fully dispatchable power source.[45] It enables flexible and more profitable operation that complements variable renewables by shifting output to times with higher electricity prices.

In most cases, only seasonal variations in precipitation and meltwater inflow affect hydro capacity factors. Accordingly, it is roughly independent of variable renewable generation shortfalls and can help fill longer supply gaps if a large enough reservoir is available. However, droughts are increasingly affecting existing hydropower, and this will only become more pronounced as climate change progresses (see Box 6).

Climate Change and Water Scarcity

Box 6

Lack of precipitation can have a strong effect on annual hydropower output. Droughts in Europe in 2022 reduced hydropower production by 19% overall, with extremes of ~40% reduction occurring in Spain and Italy. It is estimated that reduced power output from hydropower plants in 2023 caused ~40% of the global 1.1% rise in emissions from 2022 to 2023. Globally, a third of hydro installations are currently in regions with an increased risk of water scarcity, but reductions in usable capacity are expected for the majority of plants (60–75%) from 2040 onward [55].

Climate change reduces precipitation in some areas while increasing it in others. Inflows are expected to increase in Northern Europe and decrease in Southern and Central Europe, especially in the hot summer months of June to October. Overall, this is expected to result in a decrease in power production of approximately 10%, largely offsetting efficiency improvements from modernization.

Potential in the EU

The potential for new hydropower is highly dependent on location. Because a given volume of water at elevation contains only quite moderate amounts of extractable potential energy (roughly 500–1000 times less energy per volume than a battery[46]), large quantities of water are needed for substantial power generation. Geography determines where large amounts of precipitation are concentrated and channeled by rivers[47]. Furthermore, geography determines where it is feasible to make use of or engineer a substantial elevation difference. Although dams are among the largest human-made structures on the planet (in terms of the mass moved for construction), they are still dwarfed by the mass of the reservoir water they contain, which is hundreds of times greater. Moreover, the combined mass of the dam and reservoir water is negligible relative to the natural rock and earth providing the bulk of a reservoir's containment. Accordingly, without suitable topography and hydrology, it is not feasible to engineer the harvesting of meaningful amounts of energy from the movement of water.

Compared to geothermal and nuclear energy, the specificity of the natural geographic conditions required for hydropower make it a more limited option for firm power. But where the conditions are fulfilled, hydro is an excellent clean option to flexibly complement renewables via integrated storage in the form of a reservoir. However, in practice there are significant disadvantages to exploiting even a fraction of the estimated 5,700 TWh of remaining economic (<100 USD/MWh) global potential for hydropower generation [56]. For comparison, global electricity production in 2024 was around 31,000 TWh [42].

For most sites, developing the hydro potential means flooding a massive area of land, requiring the relocation and compensation of its inhabitants, irretrievably destroying local ecosystems, while significantly affecting others upstream and downstream of the dam, and causing many other mostly negative side effects. Run-of-river hydro without substantial reservoir capacity has fewer drawbacks, but its lack of integrated storage reduces its value for complementing renewables. One estimate for the remaining global potential after taking these factors into account is 2,200–3,300 TWh depending on the stringency of ecological restrictions [56].

In Europe, most of the potential has been harnessed already since the 20th century when political and public acceptance were more conducive. The potential for growth thus lies almost exclusively in modernizing existing infrastructure. Taking into account the ecological restrictions mentioned above, 150 TWh of economic[48] hydro potential remains in Europe; for comparison, the electricity consumption of the EU in 2025 was 2,800 TWh. Considering future growth in electricity demand from electrification, as well as year-to-year fluctuations in hydro production due to weather patterns, hydropower clearly cannot provide a dominant fraction of Europe's electricity needs, yet even its modest share still has an important role to play in complementing variable renewables and stabilizing Europe's energy system, as it already does today.

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[44] In places with exceptionally large tidal range, i.e. the difference between the sea level at high tide and low tide, or where tidal flows are concentrated by geography, tidal hydropower may be used. In this case the water above the elevation of the tidal hydro plant is largely transported via gravitational interactions with the moon and the sun, rather than the hydrological cycle, which generally confers much less energy. This is part of the reason why the potential for tidal energy is much lower than that of conventional hydro.

[45] If a second lower reservoir and pump are added, then pumped storage turns the plant into a large-scale energy storage asset for the grid, in addition to already being a dispatchable power generation asset thanks to the first reservoir.

Nuclear

Nuclear reactors have been deployed at scale across the world for decades, motivated in part by energy security concerns[49] (the so-called Messmer Plan that kickstarted the deployment of civil nuclear in France was an explicit measure to reduce the country's energy dependence following the oil crisis of 1973 [57]). Nuclear power plants use uranium as a fuel to generate heat from nuclear fission reactions, where large radioactive atoms break down into smaller ones and release energy in the process. Typically, this heat is then used to drive a steam turbine which generates electricity. While nuclear and hydropower have historically been the main sources of clean electricity worldwide, the relative share of nuclear within global electricity generation has been steadily declining since the 2000s while absolute output has been relatively stagnant (only 6% growth from 2000 to 2023) [43].

Fusion

Box 7

There are two types of nuclear reactions: fission, where heavy radioactive atoms (like uranium) release energy by breaking down into smaller atoms, versus fusion, where light atoms (like deuterium, an isotope of hydrogen) release energy by merging into bigger atoms. It has been pursued for decades but the combination of both fundamental scientific and applied engineering challenges (e.g. understanding fusion reactions, plasma behavior and control, material requirements) encountered along the way have so far not been overcome to reach the milestone of "net energy gain"[50] at the reactor level (i.e. extracting more energy out of the fusion reaction than the input to start it).

Thermal power output from a tokamak fusion plant scales proportionally to [58], where R is the size of the reactor and B the strength of the magnetic field, i.e. increases in both of these parameters yield massive gains in output. Breakthroughs in stronger magnets would therefore unlock significant gains for fusion. Reactor size dependency means there is a considerable incentive to scale up (doubling the reactor size would give an eightfold increase in output, for example), which makes prototype iteration slow and difficult. Construction of the ITER reactor (long considered the next big step for tokamak fusion and the one to demonstrate net energy gain) started in 2013 and is scheduled to start operating in 2039; it requires a level of capital investment that only a global consortium of governments can afford (€25 billion[51] [59]). Alternative approaches such as inertial confinement are more amenable to smaller scale experimentation, which is in part how a flood of startups have recently been joining this endeavor and raising significant private capital for the first time (billions of dollars since 2021, roughly 10–100 times more than before this period).

While achieving fusion is scientifically plausible and worth pursuing, at the historical rate of progress (see Figure 18 from [60]), the prospect of doing so and then scaling it up commercially with a globally significant fleet of reactors comes with a deeply uncertain timeline. In the meantime, until 2050, the other sources of clean firm power highlighted in this report have a higher probability of making a meaningful contribution to a clean and resilient global energy system, which is why fusion is not considered in more detail here.

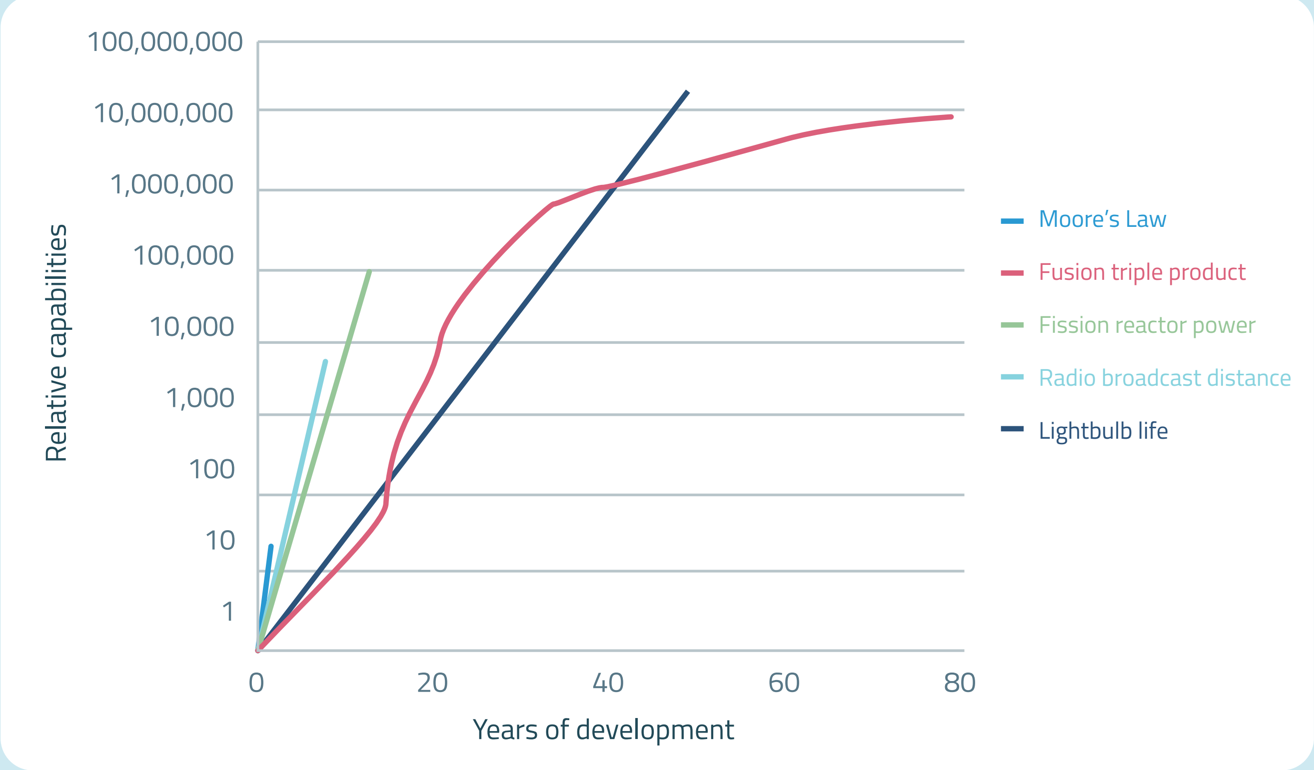

Figure 18: Historic pace of progress for various technologies. At the early stages of development, improvements by orders of magnitude are required to become genuinely useful; a speed at the level of Moore's Law is only impressive for an established technology but disappointing for a nascent one.

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[49] Nuclear fuel (uranium) is relatively widely available and has an extremely high energy density, about 100,000 times higher than coal, making it a portable fuel that is easy to store in strategic inventories; power plants typically store two years' worth of supply. In this way, nuclear contributes to energy security.

[50] The US National Ignition Facility has successfully used lasers to reach net energy gain at the reaction level (the laser energy was lower than the output of the fusion reaction) but this excludes this far greater energy expenditure to run the laser itself, so net energy gain at the power plant level has not yet been demonstrated.

[51] The budget figures are somewhat disputed and will only ever truly be finally clear once the project is complete and running.

The main problems holding nuclear back from a more prominent role in the decarbonization of Western economies today are cost and time, i.e. it is expensive and slow. To a large degree, this is not so much a feature of nuclear in itself, but rather typical of large, non-modular infrastructure projects more generally [61]. While there are countless reactor designs[52] (the most common one being pressurized water reactors [62]), each with its own benefits and drawbacks, the more important distinction for the future of the nuclear fission industry is between continuing to build conventional large-scale reactors (typically around 1 GWelectric) versus transitioning to small modular reactors (SMRs, in the hundreds of MW or less).

Still, even though the problems of large-scale conventional nuclear are certainly very real in the West, there is substantial evidence that they are not inevitable under the right conditions, as was the case in the 1970s/1980s and can be observed currently in regions such as China or South Korea.

Speed

Nuclear is generally taken to be slow to build, certainly compared to solar and wind, which is a significant disadvantage given the urgency of geopolitical problems of energy insecurity and climate change. Yet the global average is that 85% of reactors have been built in under 10 years (see Figure 19 [63]); however, it is important to note that the distribution of build times is fat-tailed, i.e. a minority of projects take much longer to build than the average [64]. This is due to attrition of nuclear construction know-how in the Western world over the decades with little to no new builds (a trend that is not present in other geographies, such as China). This is not the case for solar and wind, which are modular and cluster much more closely to their average value, making deployment more predictable and reliable.

Historically, it has been possible to build new nuclear plants at a rate that rivals that of current wind and solar combined (see Figure 20 [65]), namely in the peak periods for nuclear in Sweden and France in the 1980s. However, this depended on a high level of ambition, stemming directly from a period of high demand growth and the quest for energy independence following the oil crisis; whether similar levels of determination can be summoned today is an open question, although the underlying motivational factors are arguably strong (climate change, energy security, and a new surge of load growth from electrification and the rise of AI). Fundamentally, building continuously and standardizing is what enabled the establishment of robust supply chains and know-how to deliver these high rates of nuclear deployment. On the other hand, the deployment of solar and wind is still accelerating and therefore likely to overtake the nuclear record; how much further they will accelerate is an open question, given the constraints they face (e.g. grid access and permitting, reduced profitability due to cannibalization). Nevertheless, past predictions of renewable growth tapering off have been drastically wrong so far, lending credence to the view that no slowdown is in sight.

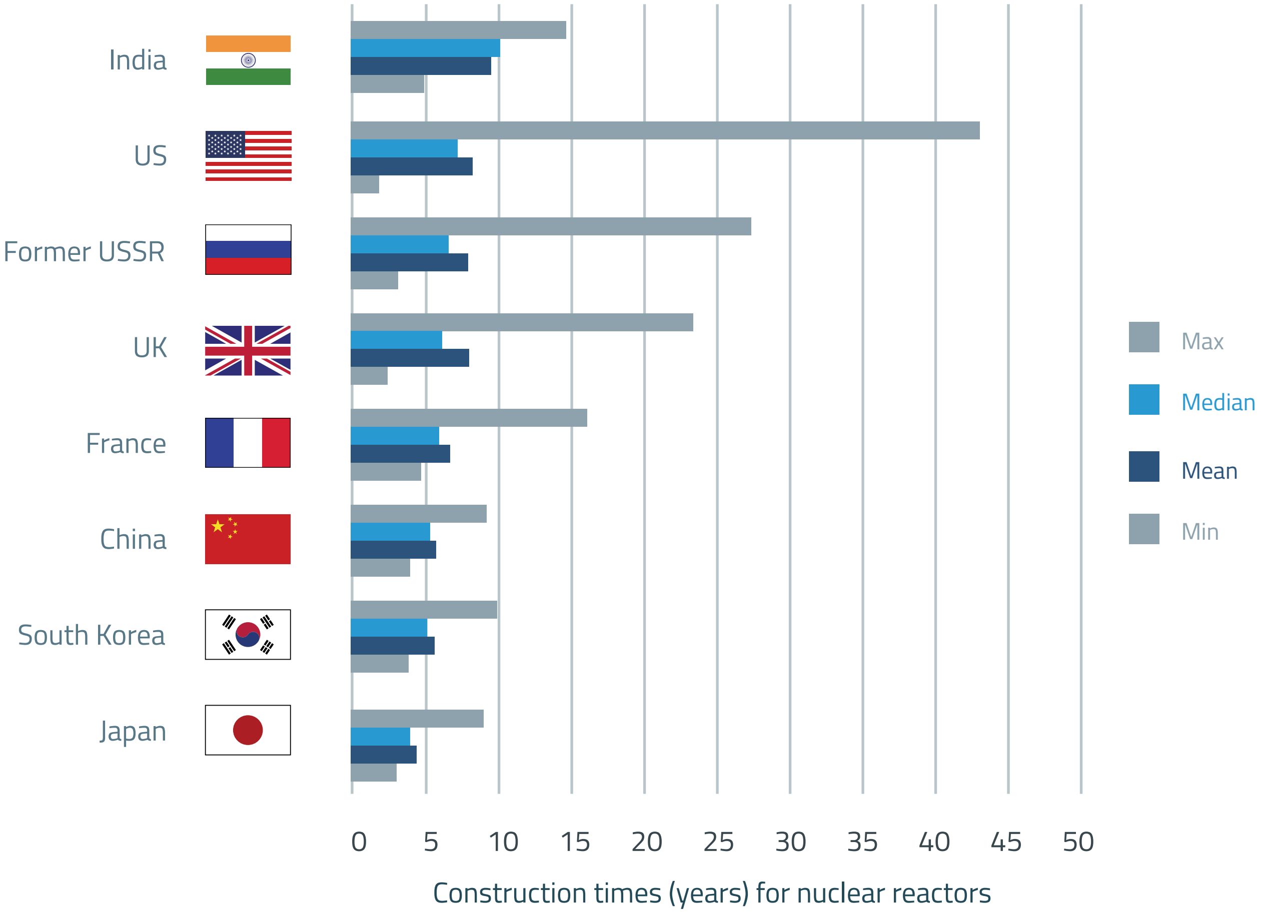

Figure 19: Statistics of construction time (years) for nuclear reactors by country. Source: data from IAEA Power Reactor Information System

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[52] Such as pressurized water reactors (PWRs), boiling water reactors (BWRs), breeder reactors, molten salt reactors, high-temperature gas-cooled reactors, and more.

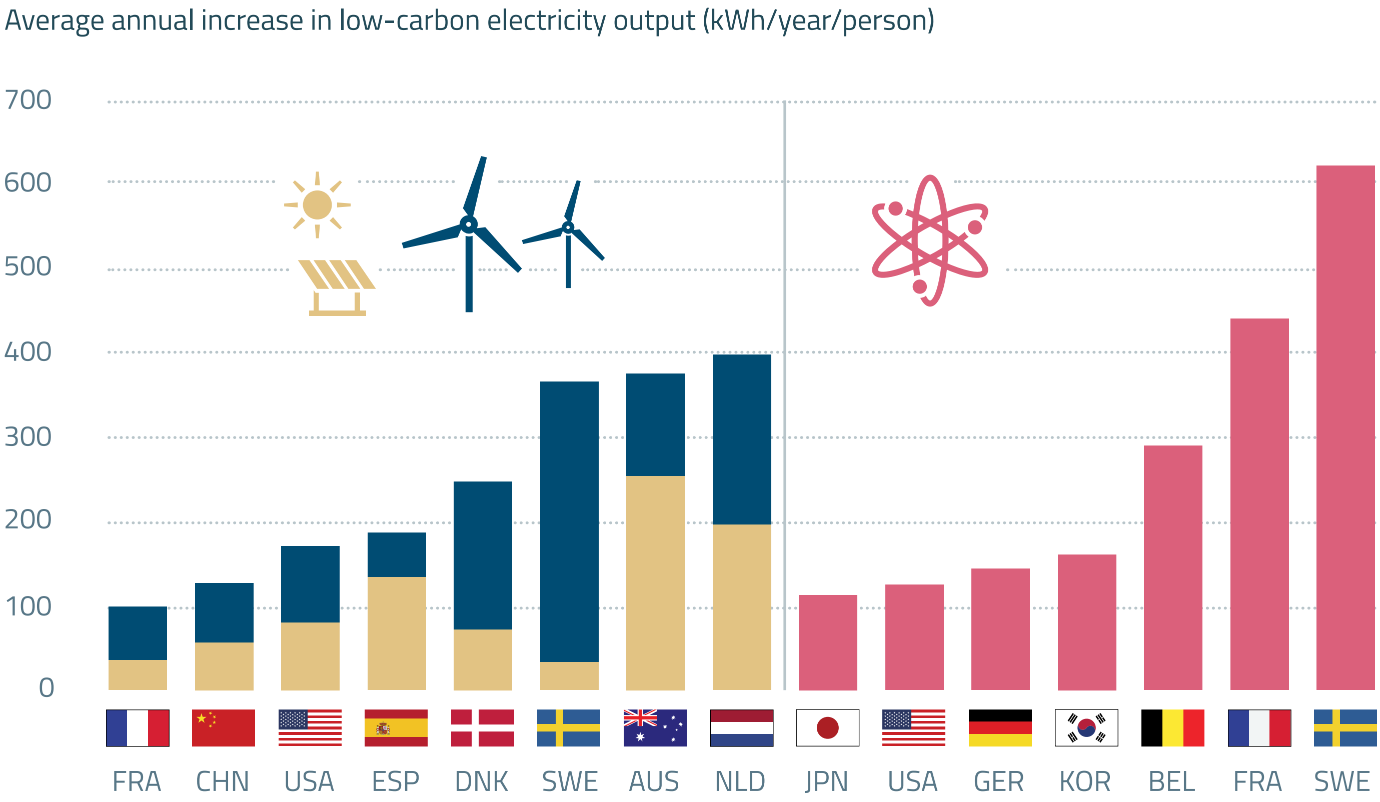

Figure 20: Comparison of record deployment rates for low-carbon electricity. Solar and wind data from 2019–2023; nuclear data from historical peaks (mostly 1970s and 1980s, except South Korea 1995–2005). Source: Sustainability by Numbers with original data from Ember [65]

Cost

Building a new nuclear plant today is generally taken to be expensive and frequently running over budget in Western countries, although this phenomenon is arguably a feature of large infrastructure projects more than of nuclear itself. To make a difference in Europe's clean energy future, nuclear would need to become cheaper, and charting a path to doing so first requires understanding its current cost structure. As shown in Figure 21, the breakdown of nuclear's levelized cost is typical of clean energy projects in that it is dominated by capital expenditure rather than operational expenditure, because its fuel is relatively cheap. Notably, the capital cost is itself driven by the financing and interest repayment[53] because the loans are so large and over the long term: In OECD countries, 67% of LCOE is financing cost [66]. In a way, the technology is cheap, while the financing is expensive.

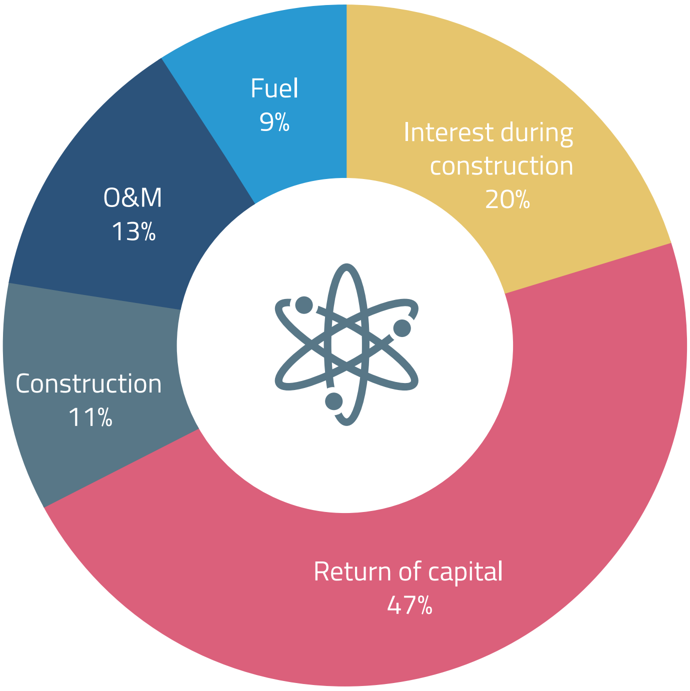

Figure 21: Cost breakdown of levelized cost of nuclear electricity. Source: data from OECD Nuclear Energy Agency [66]

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[53] Hence the common refrain that, for nuclear, the challenge isn't capital cost, but rather the cost of capital.

Not only are conventional nuclear plants essentially large infrastructure projects, but they are also intensely (though understandably) regulated.[54] The combination of these two factors results in high indirect costs, around a third of the capitalized cost of a benchmark PWR plant in the United States [67]. More concretely, 40% of the overnight cost stems from engineering and project management labor, because heavy regulation notably entails significant documentation throughout the construction process; by contrast, construction labor is only 17%. The equipment itself is merely 18% of the overnight cost, although even this item is inflated by strict quality control requirements specific to the nuclear industry (concrete and structural steel in nuclear plants face a premium of around +30% and +60% respectively compared to the same materials in other industries [68]). In general for megaprojects, a strong lever for cost reduction is making the system more modular; while this is by nature difficult, it is not impossible, with successful examples including Madrid's metro [69].

High regulatory standards are only part of the issue for nuclear. It is also the constantly changing nature of these regulatory requirements that drives up cost: Updates from one plant to the next are detrimental to standardization and therefore cost reduction, while updates when a project is already underway require expensive rework during construction. Consequently, there is a strong correlation between high capital costs and low design completion rate at the start of construction [67].

Long construction times (by design or by delay) are particularly damaging because financing costs are high: As can be seen in Fig. 22, for the same overnight cost, a plant that takes ten years to build instead of five would triple in absolute terms the cost of interest during construction. In reality, the picture is even worse, since a delayed plant would see its overnight cost increase as well during that time, while postponing the start of revenue generation. Long construction timelines also increase the risk of regulatory changes and disruptive "black swan" events. Finally, because the share of financing to total cost is high, the interest rate is also an important factor.

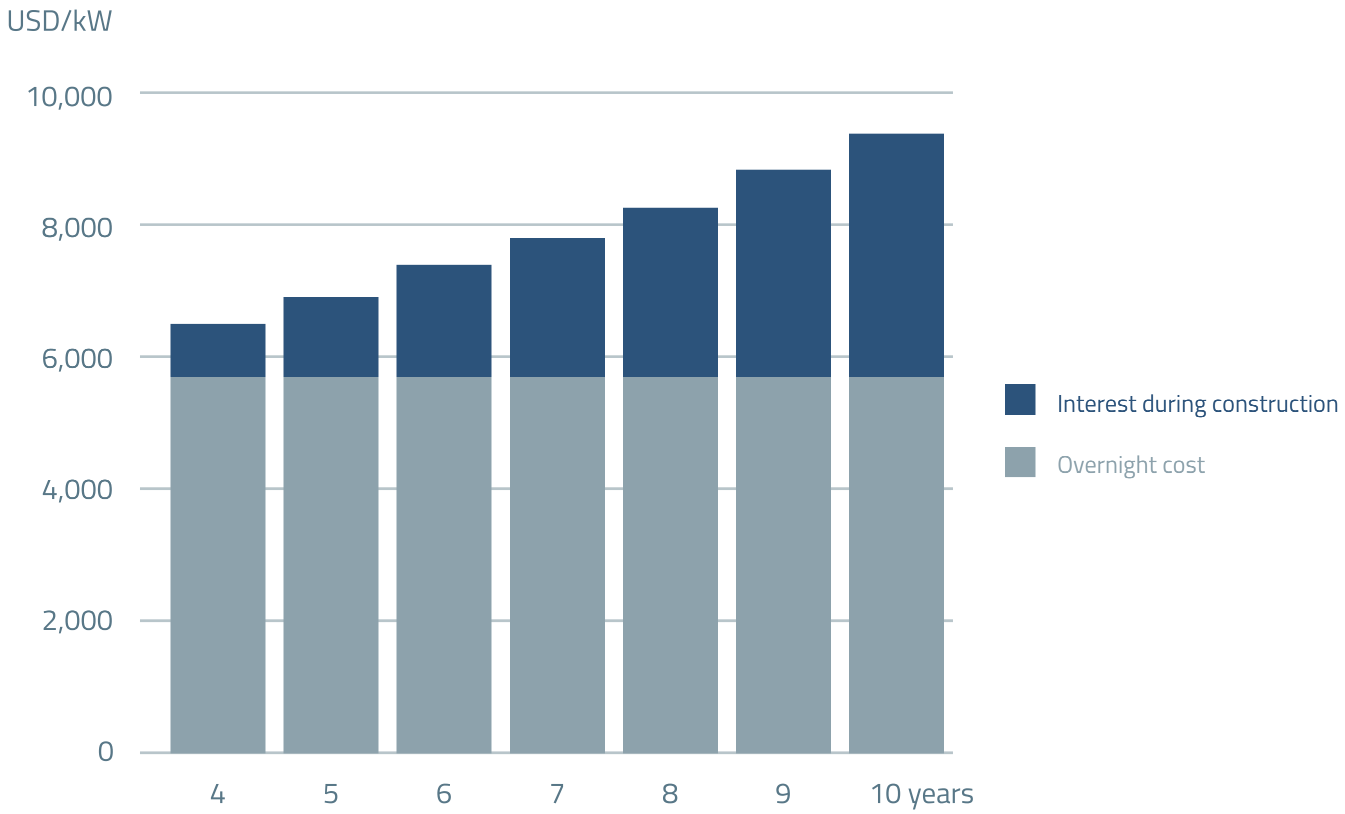
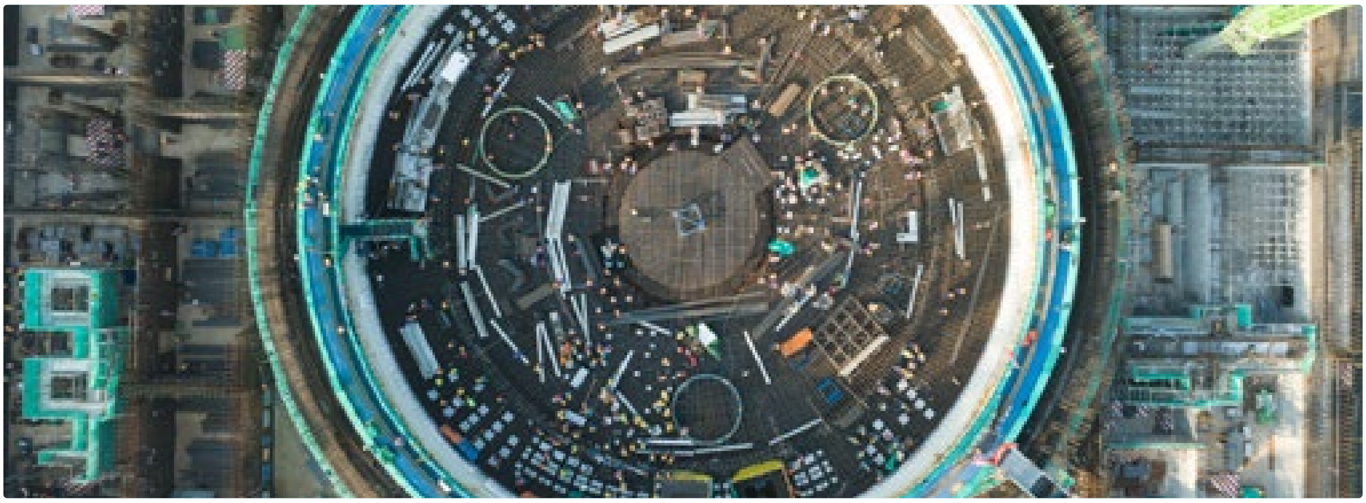


Figure 22: Cost as a function of total construction duration (years) for a benchmark US PWR



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[54] Some of the guiding principles underpinning nuclear regulation are hotly debated: "ALARA", which stands for risk management as low as reasonably achievable, creates a never-ending pressure on nuclear safety standards, which increases costs while delivering diminishing returns to public safety.

Table 1 summarizes the characteristics that distinguish high- and low-cost nuclear reactors [67]. While cheap nuclear is certainly possible (e.g. in the West in the 1970–1980s, and in China today), the scale of conventional nuclear projects essentially makes them the sole preserve of strong-willed national governments; in other words, one might call nuclear "too big to scale" in purely private markets. Moreover, as for any industry's long-term longevity, continuous activity is essential to developing and maintaining mature (and therefore low-cost and resilient) supply chains; conversely, a series of sparse one-off projects requires more wasteful effort reinvesting anew into a rusty supply chain.

Table 1: Characteristics of low-cost vs high-cost plants

High-cost plants	Low-cost plants
▸ Lack of completed design before construction started ▸ "First of a kind" (FOAK) design ▸ Major regulatory interventions during construction ▸ Insufficient oversight by owner ▸ Litigation between project participants ▸ Significant delays and rework required due to supply chain ▸ Long construction schedule ▸ Relatively higher labor rates and low productivity	▸ Design at or near completion prior to construction ▸ "Nth of a kind" (NOAK) design ▸ Intentional new build program focused on cost reduction and performance improvement ▸ Experienced construction management ▸ High degree of design reuse ▸ Low cost and highly productive labor ▸ Experienced EPC (engineering, procurement, and construction) consortium ▸ Experienced supply chain ▸ Detailed construction planning prior to starting construction ▸ Multiple units at a single site

Small Modular Reactors

If the scale of conventional nuclear is indeed too large to be deployed without strong government backing, then some proponents see so-called small modular reactors (SMRs) as the way forward, with considerable interest from the private sector: the International Energy Agency (IEA) expects SMRs to represent 17–33% of cumulative investments in nuclear energy over the period 2024–2050 [29]. SMRs are classified by reactor sizes that are small enough to be manufactured in a factory as modules. Modules can then be added together, to any desired plant capacity. They can in theory ease the key issues facing nuclear: By mass-producing reactors as *products* in factories rather than bespoke on-site infrastructure *projects*, standardization and higher learning rates could be leveraged to reach economies of numbers and reduce costs over time. Moreover, timelines would be improved with faster and more reliable delivery of reactors, which would also have substantial positive cost implications (as discussed above regarding the cost of capital and how delays exacerbate this).

Crucially, this means that the risk profile of SMRs could be radically different to conventional nuclear (less budget and timeline overruns, making SMRs a more palatable prospect) and SMRs would lower the bar for the absolute CAPEX required, allowing new suppliers and consumers to enter the market for nuclear power. The private sector could enter a field historically limited by its sheer scale to governments.

However, the theoretical benefits of SMRs have yet to be proven in reality; the cost estimates for the first SMRs are rising, e.g. with NuScale's target price for its deal in Utah in the United States, increasing over 53% from 58 USD/MWh in 2021 to 89 USD/MWh in 2023 (even with subsidies from the Inflation Reduction Act) [70]. Smaller reactor sizes face tradeoffs with economies of scale which push design choices in the opposite direction. In power plants and chemical plants, bigger is cheaper (per unit of output); this is basically an extension of a well-known engineering heuristic (the so-called "six-tenths" rule[55]) that scaling up the capacity of a piece of equipment increases costs less than proportionally. This is the reason why nuclear power plants have historically been made as large as possible, and why most SMR designs are in the 100–300 MWe range and therefore tend not to be that "small" in absolute terms. Because of this tradeoff between economies of numbers versus economies of scale, it is not a settled debate that SMRs can deliver significantly better than best-in-class conventional reactors when it purely comes to levelized cost; only real-world experience at scale would settle this question definitively for Europe and the United States.

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[55] For example, the cost of a pipe only increases as roughly the square root of its capacity, i.e. doubling its capacity makes unit costs 30% cheaper. This is the reason why nuclear power plants have historically been made as large as possible.

Public Opinion and Common Concerns Around Nuclear Reactors

Box 8

While the main issues holding back nuclear deployment in Europe are arguably its high cost and slow build rates, there are other frequently raised concerns, especially from civil society.

- "Is it low-carbon?" As shown below, nuclear energy has one of the lowest carbon intensities of any electricity source, even lower than wind and solar photovoltaic [71]. From an emissions perspective, the most important question is to phase out fossil fuels, rather than nitpick between nuclear and renewables."Is it safe?" While the risks of nuclear tend to be very high-profile with rare but large accidents, the health impacts per unit of electricity production are statistically very low, on par with wind and solar photovoltaic, even when including Chernobyl and Fukushima [71]. Fossil fuel power generation is 100–800 times deadlier than nuclear yet faces much lower public resistance due to its diffuse and less visible nature, as well as being part of the status quo.

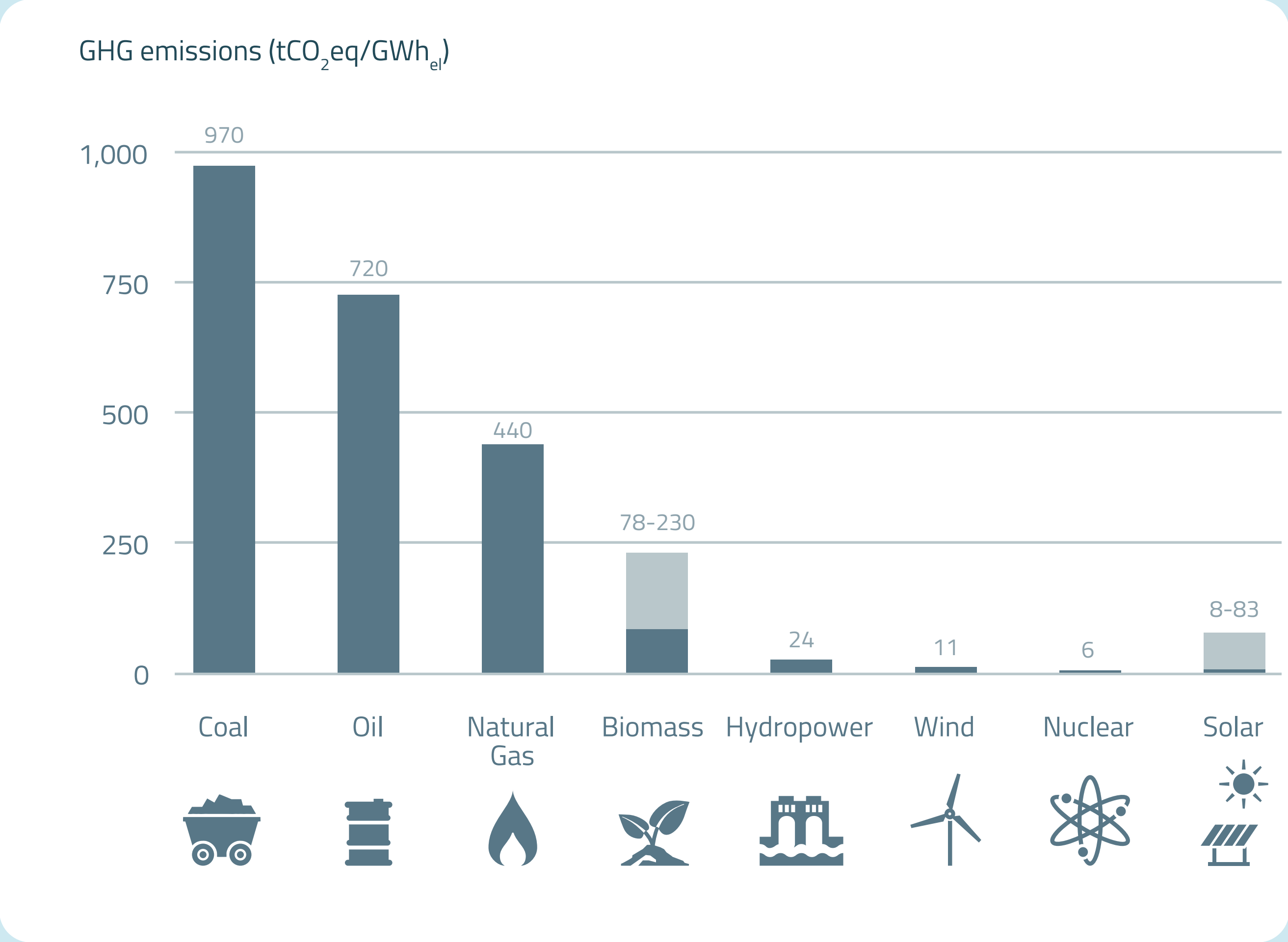

Figure 23: Greenhouse gas emissions intensity of various electricity sources

Box 8 (continued)

- “What about radioactive waste?” Uranium is a fuel with an extremely high energy density and spent nuclear fuel can be reused, such that even in a country like France that relies mostly on nuclear power, this results in about 2 kg of waste per person per year [72], so the quantity of waste to dispose of is low overall. Furthermore, over 90% of this is classified as low-level (i.e. safer and cheaper to handle) and only a small fraction (less than 1% [73]) is the more challenging high-level waste.In sum, all human activity has an environmental impact and so the key question is comparing different options quantitatively and dispassionately. While public perception has historically over-estimated risks associated with nuclear, the consequences on the reputation of the nuclear industry and its political acceptability are very real; for example, the Fukushima accident directly led to the political decision in Germany to precipitously phase out its nuclear fleet of 20 GW$_e$ (a quarter of its electricity production at the time) within 12 years [74]. Building more trust with public stakeholders therefore remains an important ask for the industry in order to retain its social license.

Nevertheless, there is a strong basis already according to a detailed 2024 survey of Europe’s citizenry [75], with 48% supporting building more nuclear plants versus 32% opposing; in 18 out of 25 countries surveyed, support for new nuclear outnumbers opposition. Crucially, while opinion tends to split along left/right political leanings, complementarity is more popular than competition, with 56% favoring “renewables plus nuclear” compared to 40% favoring “renewables only”; 81% of nuclear supporters also support renewables and 49% of renewables supporters also support new nuclear. This contrasts starkly with the political debate in certain countries that tends to unproductively frame the discussion as an either/or.

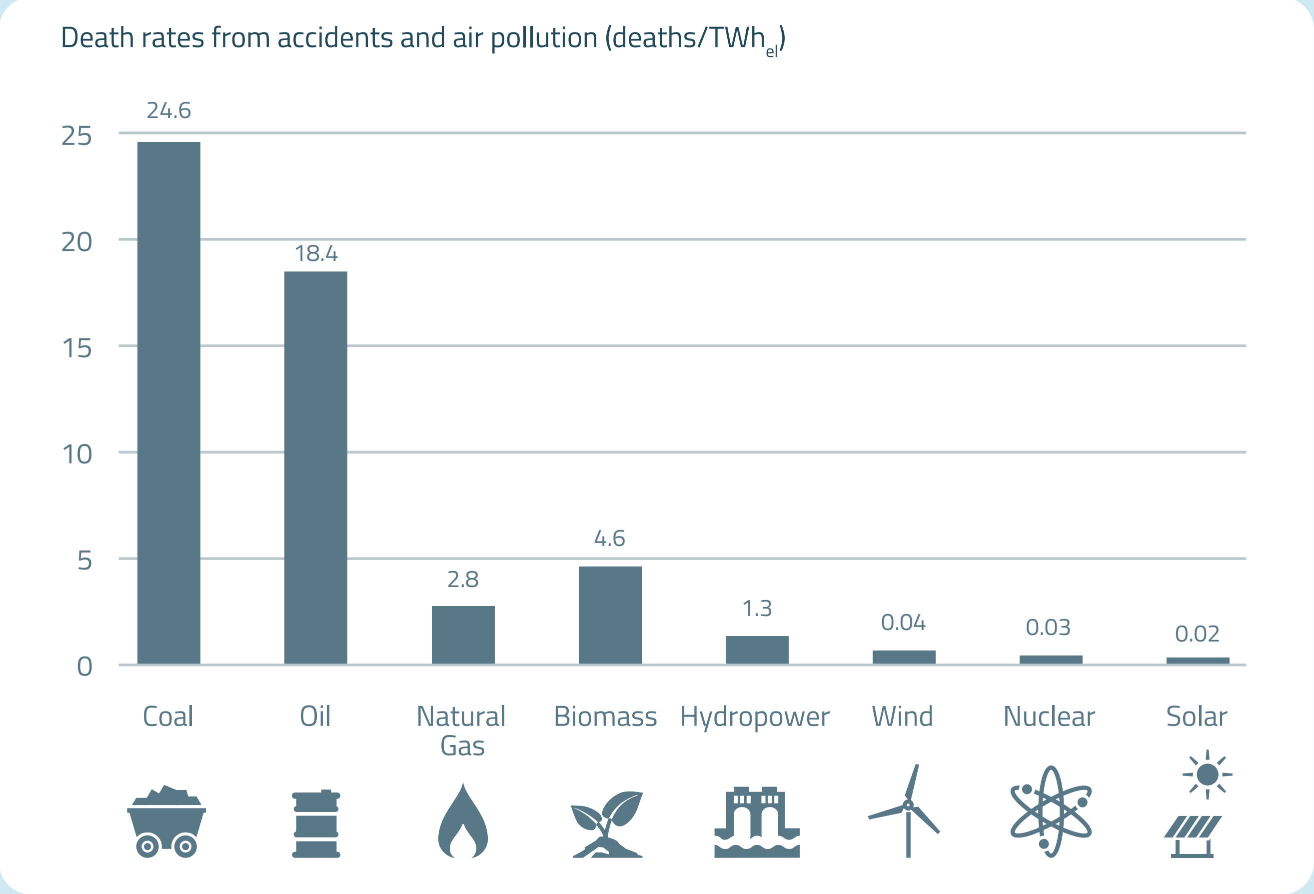

Figure 24: Death rates from accidents and air pollution

Flexibility

Nuclear power plants (NPPs) tend to be operated at a steady state, which has led to the perception of it being an inherently inflexible technology. However, this is more to do with economic constraints, rather than technical limitations [76]; maximizing the capacity factor (or load factor) of nuclear plants over their lifetimes is simply the best way to financially recoup costs, since these are dominated by CAPEX rather than fuel. However, as highlighted previously in this report, modern power grids are trending toward more variability in supply from wind and solar, with corresponding volatility in hourly electricity prices. This volatility includes an increasing fraction of hours with low (and even negative) prices; at these times, nuclear's output serves to minimize its loss rather than maximize its revenue. It is likely that the economics of a nuclear plant can be enhanced, if electricity production can be shifted from lower to higher price hours with only a moderate increase in CAPEX. This would be much more valuable to the grid in complementing variable renewables rather than as baseload. From a technical perspective, there are two kinds of flexibility available to nuclear plants: flexing the output of the reactor and thereby the whole plant; and flexing only the power block while keeping the reactor at steady state via thermal storage as a buffer.

Flexing the Reactor

Firstly, strong load-following capabilities of NPPs are actually a standard feature of modern designs to be able to follow both daily and seasonal fluctuations in demand. This is already the case in France, where 40% of the fleet [77] is involved in load-following and some NPPs see one or two large power changes per day; the impact of load-following on the average capacity factor is estimated at 1.2% in France. Modern designs must be capable of at least daily load cycling operation between 50% and 100% of rated power, with ramp rates of 3–5% per minute. Because these maneuverability requirements are integrated in the design, the impact on accelerated aging of large components is very limited. However, since economic incentives strongly push the capacity factor as high as possible, this approach is limited to downward flexibility (ramping down from the rated maximum) and therefore tends to be adopted in practice only for grids with high shares of nuclear such as in France. Finally, timing maintenance schedules in summer[56] with peak production in winter complements solar photovoltaic in Europe, providing a degree of seasonal balancing, even if this is indirect.

Flexing with Thermal Storage to Keep the Reactor at Baseload

Secondly, generation-integrated thermal energy storage systems have also been proposed as a mechanism to flex the nuclear plant's electricity output. In its simplest form, the reactor and power block are decoupled: The heat output from the reactor is kept constant and only the power cycle is flexed, with thermal storage bridging the two via an intermediate storage loop [78], [79]. This enables both *downward* and *upward* flexibility of the nuclear plant's electricity production. Depending on reactor design and the correspondingly compatible options of thermal storage, the duration of this flexibility can range from hours to days (e.g. sensible thermal energy storage in molten salts, thermal oils, or packed beds of rocks [80]; latent thermal energy storage in phase change materials (PCMs) such as eutectic salts [81]), to even weeks or seasons (when supplemented with underground thermal storage).

Instead of separating the reactor and power block with storage via an intermediate storage loop, a range of recent academic work has focused on storage integrated directly within the power cycle. Systems typically differ with (i) where in the plant integration occurs and (ii) the thermal storage medium.

Many studies integrated storage near the inlet to the high-pressure turbine, which is usually the hottest point in the power block [82], [83], [84]. In these configurations, a fraction of the steam is diverted from the turbine inlet to charge the store; however, because the extracted steam often lies in the two-phase region, storage design must consider the effectiveness of heat transfer. Often PCMs are proposed because they can effectively integrate with the two-phase steam [81], [85]. Storage is typically discharged into lower-pressure turbine stages or via separate peaking turbines, and reported flexibility of up to 10–20% is available depending on the design. An alternative approach considers tweaking flows in the hot-liquid feedwater system for greater storage efficiency (>80%) and flexing capabilities around 10% of rated power [86]; while this may seem relatively small, the sheer size of the average NPP (typically about 1 GW_e) means that even this fraction represents a significant flexibility source in absolute terms for the grid.

Bidirectional flexibility via thermal storage is more economically advantageous because it maximizes the capacity factor of the reactor (the single most expensive piece of equipment in the plant), while also providing a better opportunity for maximizing revenue by shifting power production from low to high price periods.

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[56] Summer heatwaves are also at times suboptimal for nuclear production since rivers can become too warm for nuclear plants to use them for cooling within mandated temperature limits, resulting in curtailed power.

The economic viability of this strategy is predicated on the CAPEX of the power block (steam turbine, generator, etc.) and thermal stores being much lower than that of the reactor (depending on the size of the storage system, this may increase plant CAPEX by about 2–15% [87]). Nuclear flexibility becomes more and more valuable with increasing penetration of variable renewables on the grid. Research on nuclear flexibility via thermal storage is not new; however, it is only with the changing landscape of increasingly volatile electricity markets that the incentive to implement this becomes tractable. Modeling shows that flexible nuclear plants economically outperform baseload ones in markets where energy price peaks are double the mean price [88].

Accordingly, nuclear flexibility via thermal storage has recently started to attract commercial interest and development, with startups such as TerraPower in the United States or HEXANA in France proposing molten salt thermal storage with the explicit intention of integrating with renewables. This should be encouraged as part of any national energy strategy involving nuclear.

Potential in the EU

The potential of nuclear in the EU is not limited by typical concerns such as the availability or price of fuel. Rather, it is defined by speed and cost and can be more subtly characterized as a spectrum that is conditional on the level of our collective ambition.

Low Ambition

- A low-risk priority for nuclear power is extending the lifetime of current plants, as this is arguably the cheapest and fastest (almost immediate) form of clean firm power that can be deployed; the LCOE of a nuclear plant extended by 10–20 years is estimated at around 30 USD/MWh compared to 65 USD/MWh for a new build [89]. Considering that the EU currently has 100 reactors in operation providing 98 GW_e of power across 12 member states,[57] and that the age of the fleet is relatively old,[58] then this strategy potentially buys Europe tens of gigawatts of clean power over the coming decades while wind and solar continue to deploy.

- For nuclear plants that do end up being shut down and decommissioned, the brownfield site still retains value that can be leveraged and repurposed as a different clean energy asset, such as reusing the existing grid connection and permits to build a battery storage site that supports the further integration of variable renewables. For example, Germany's last three nuclear reactors were shut in 2023 and are unlikely to make a comeback in their nuclear form.

High Ambition

- "Repowering" is a form of retrofit where coal power plants are converted to nuclear power. Because of the overlap between these two types of power plants, a nuclear reactor can replace the coal burner while reusing other parts of the existing plant[59]; this includes physical equipment (such as steam turbines, generators, grid connections) as well as permits and the local workforce. This preserves the value of the site and is therefore estimated to lower upfront capital costs by roughly 30% compared to a greenfield installation [90]. Within Europe, Poland is best placed for this strategy given its large coal fleet and openness to nuclear power.

- Whether conventional or SMR, the key is getting a sufficiently large order book, then fully standardizing and freezing designs, facilitated by regulatory harmonization (ideally internationally). This means there is a threshold below which it is likely not worth it to build new nuclear. The order book has to be large enough for many reactors, so depending on total order volume, conventional or SMR scale might be better.

- SMRs also make the market more liquid, pooling demand together, which helps with scaling up in numbers and therefore getting positive learning rates. SMRs lower this threshold.

- SMRs for direct heating rather than power generation offer another valuable business case, especially in industry, where demand for process heat is essentially constant, which fits nuclear baseload operation well. This could further enable the SMR industry to reach scale.

In all cases, plants must emphasize flexible operation where possible, since this will be valuable in grids increasingly influenced by variable renewables (and even arguably essential to the survival of nuclear in the merit order) [91]. Exploiting the flexibility potential is an economic problem more than a technical one; therefore, market reforms may be required to ensure that nuclear power plants receive sufficient financial compensation for the flexibility services they can provide. The more it can be made flexible, the more it can thrive by complementing wind and solar rather than competing with them.

Historically, the successful periods of nuclear deployment (France and Sweden) have had in common that they saw high growth of electricity demand, which justified this investment and paid off. In a world of electrification of entire sectors such as transport, heating, and industry, plus the demand for AI data centers, Europe's nuclear prospects are once again gaining momentum, such as with the Nuclear Alliance of 14 member states.

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[57] These are: Belgium, Bulgaria, Czech Republic, Finland, France, Hungary, Netherlands, Romania, Slovakia, Slovenia, Spain, and Sweden. Half of the EU's nuclear electricity production is in France.

[58] The average age of France's nuclear plants is 37 years.

[59] The extent of reuse depends on the age of the coal plant's equipment, so repowering is more of a spectrum than a single formula for retrofit.

Geothermal

Geothermal energy is a renewable energy source which harnesses naturally occurring thermal energy stored in the Earth's subsurface. It is typically accessed via drilled wells, where a working fluid is circulated to extract heat. Depending on its temperature, this heat can be used either directly, such as for heating a building or an industrial process, or it can be used in a power plant to produce electricity.

The temperature of the heat is generally determined by depth: The deeper the drilling, the higher the temperature of the thermal resource, which directly translates to both more energy available and higher efficiencies of electricity generation. Typically, the temperature of the earth rises by around 30°C per kilometer of depth. In certain locations, the earth is warmer closer to the surface than in others, but in principle geothermal energy is available everywhere, if one drills deep enough. In fact, at around 7 km of depth, the usable energy contained in a 400 m thick layer of rock at around 250°C is comparable to that in a shale oil deposit.[60]

For the sake of brevity, this report focuses on geothermal for electricity generation,[61] but its potential for direct use in heating and cooling buildings or industrial processes is significant and should not be overlooked.

Conventional and Innovative Geothermal Power

Conventional Geothermal

Conventional geothermal, more specifically known as hydrothermal, started in the early 20th century in Italy. It requires three conditions: elevated ground temperatures at a depth reachable by conventional drilling; the presence of water in the ground as a heat transfer medium; and sufficiently permeable rock so water can flow through the reservoir (Figure 25). This specific set of geological conditions is limited to only a few areas globally, most famously Iceland, where 30% of energy is produced by geothermal. However, these conditions are rare and will never scale to meet a noticeable fraction of global energy demand, despite being a commercially mature technology. In 2022, only 0.1 GW of new geothermal capacity was added worldwide, which is equivalent to less than a single gas power plant.

Next-generation geothermal technologies seek to overcome these limitations by artificially creating the conditions for geothermal energy generation (Figure 25), such that only the first prerequisite (namely heat) is necessary. This drastically unlocks and expands the resource potential globally; the IEA estimates that the global technical potential of next-generation geothermal below an LCOE of 300 USD/MWh (an arguably high threshold) exceeds that of conventional geothermal by a factor of 2,000 (specifically *enhanced* geothermal systems (EGS), see below). This is equivalent to 140 times current global annual electricity demand.

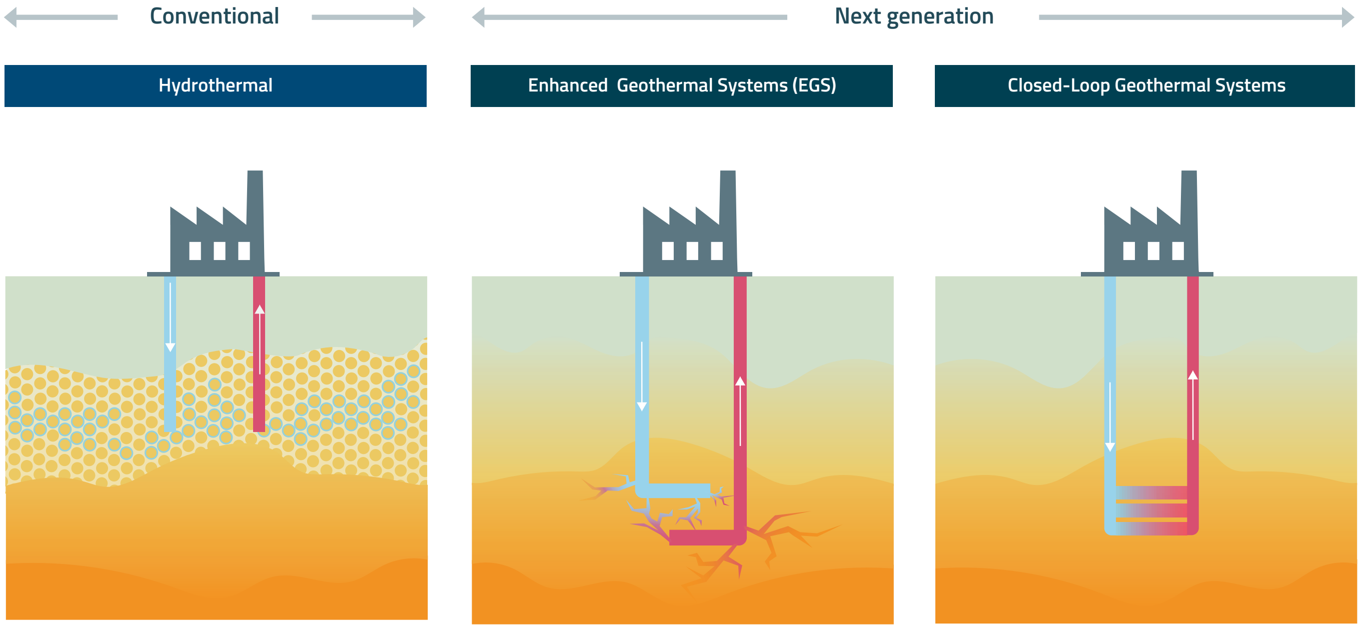

Figure 25: The various types of geothermal systems

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[60] Technical details of this comparison:

Oil: Deposit thickness 100 m, rock density 2,600 kg/m3, total organic carbon 4 wt%, hydrocarbon to carbon ratio 1.25, transformation ratio 40%, retained fraction 60%, oil density 850 kg/m3, extraction rate 15%, energy density crude oil 37.75 MJ/L, electricity conversion efficiency 60%. Calculation: 100 m * 2,600 kg/m3 *4% *1.25 *40% *60% /(850 kg/m3) *15% * 37.75 MJ/L *60% = 3.46 TWh/km2

Geothermal: Fracture network height 400 m, granite heat capacity 0.79 J/(g*K), granite density 2,630 kg/m3, ambient temperature 20°C, depth 7 km, thermal gradient 35°C/km, temperature 245°C, heat engine efficiency vs Carnot efficiency 80%, total temperature reduction 45 K, conservative linear approximation over depth and temperature range. Calculation: 400 m *0.79 J/(g*K) *2,630 kg/m3 *(245 K+273.15 K-(200 K+273.15 K)) *((1-(30 K+273.15 K)/(245 K+273.15 K))+(1-(30 K+273.15 K)/(200 K+273.15 K)))/2 *80% = 3.22 TWh/km2

[61] Including heating and cooling raises the resource potential of geothermal further, since without the conversion to electricity, the efficiency is several times higher. In any case, the analysis presented here (such as the technical challenges for development) broadly applies as much to geothermal heating and cooling as it does to geothermal electricity.

Enhanced Geothermal Systems

EGS borrows from the extensive experience of the shale oil and gas industry in the United States; horizontal drilling and hydraulic fracturing (also known as fracking) use high-pressure drilling fluid to artificially create cracks in the rock. Water can then be injected in one well and circulated through the cracks in the hot rocks, picking up thermal energy via heat transfer, until it reaches an extraction well that returns it to the power plant at the surface, ready to generate electricity.[62]

The main benefit of hydraulic fracturing is that these cracks provide a large surface area for the water to efficiently and cost-effectively pick up the heat present in the rock. In contrast to the shale industry, however, EGS requires fewer additives[63] to fracture rocks and the industry has developed protocols specifically to mitigate the risk of induced seismicity [92].

By borrowing from the shale industry, EGS has progressed very quickly and leading projects have reached commercial demonstration (technology readiness level 8–9), with the first offtake agreements signed in 2024–2025. The existence of a workforce trained in these techniques, as well as a supply chain for the equipment involved, are significant boosts. The US Department of Energy is also a strong supporter, with an Enhanced Geothermal Earthshot initiative that aims to reduce the cost of EGS by 90% to 45 USD/MWh by 2035.

Closed-Loop[64]

In contrast to EGS, closed-loop systems do not involve any fracturing. Instead, a series of hermetic pipes are drilled, through which fluid circulates to pick up heat without ever leaving the pipe (hence the name of closed-loop). The absence of fracturing also reduces any potential seismicity concerns from local communities and stakeholders. However, closed-loop systems do rely on substantially more drilling than EGS to construct the subsurface piping system with enough surface area to pick up heat between the injection and production wells. Accordingly, it is likely to cost more than EGS. In terms of maturity, it is also around TRL 8, but pursued by fewer companies.

Flexibility

Geothermal power generation has a high capacity factor, typically above 80%.[65] While this makes it very reliable, previous sections of this report have shown how baseload operation is becoming increasingly outdated in modern grids. Rather, dispatchability is needed to truly add value in grids with variable wind and solar. Next-generation geothermal systems are capable of providing greater system value (and a greater plant-level business case) by taking advantage of this variability and load-following;[66] the plant can ramp its power output up and down for hours [32]. For closed-loop, the flow rate can be slowed down so that the fluid picks up more heat, allowing for a short period of higher-temperature production when the flow restarts [93]. For enhanced geothermal systems, the pumping rates of the injection and production wells can be manipulated:

I. in steady-state operation, the pumping rates are equal

II. when ramping down, the production well's pumping rate is turned down, while the injection well keeps pumping water into the reservoir, which essentially time-shifts the energy that would have been produced to a later point in time

III. when ramping back up, the production well is turned back up above its normal rate, compensating.

When manipulating the injection and production well flow rates, geothermal facilities are effectively "doubling-up" and serving as large-scale underground energy storage ("in-reservoir energy storage" [94]), in addition to their traditional electricity generation role. Storage could be either thermal (storing energy as high temperatures) or also mechanical for EGS (by storing pressurized water in the fractured rock). Importantly, storage can be done on multiple timescales, including seasonally [95]. This potential for seasonal flexibility might turn out to be especially valuable, as other technology options for this are limited.[67] The IEA expects the market size of seasonal flexibility in Europe to lie around 500–600 TWh (i.e. 6–7% of total annual demand) between 2035 and 2050, in their Announced Pledges Scenario. Figure 26 conceptually summarizes these flexibility variants.

Thanks to this multi-faceted flexibility, estimates show that the value of dispatchable geothermal in grids with high variable renewable penetration is up to 60% higher than an equivalent baseload plant [94].

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[62] The water is then re-injected and the loop begins anew, so there is very little wastewater produced by this process.

[63] These additives adjust the fracking fluid's properties and effectiveness; for example, guar gum is added as a thickener, while sand acts as a so-called proppant, preventing the closing of newly generated cracks.

[64] Also known as "advanced geothermal systems" (AGS)

[65] Data from conventional hydrothermal taking into account thermal decline, i.e. old plants generating below their nameplate capacities because their reservoirs have cooled or are depleted of fluid. Geothermal plants typically have nearly 100% uptime, and thermal decline in next-generation technologies can be managed via supplemental drilling over the lifetime of the project.

[66] Enhanced geothermal and closed-loop are thermally limited over a project's lifetime (i.e. how quickly they extract heat determines how long the reservoir lasts), so both benefit from preferentially extracting heat only when power prices are high. This gives geothermal an effective fuel "opportunity cost," which is another incentive to operate flexibly.

[67] Hydrogen and/or chemical derivatives, pumped hydro storage.

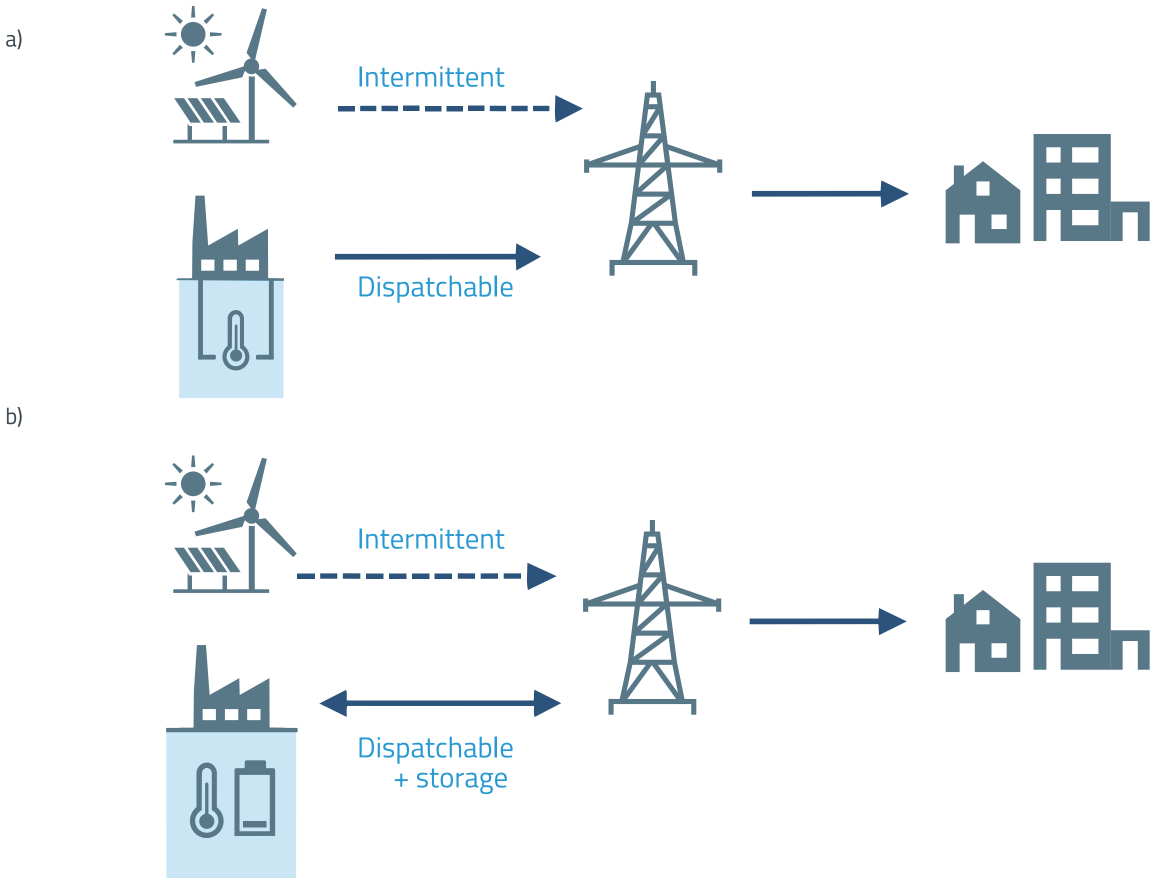

Figure 26: Geothermal grid flexibility via (a) dispatchability, i.e. ramping up and down to compensate the output of variable renewables; (b) grid-scale energy storage by doubling as an underground "battery," i.e. directly absorbing energy from variable renewables

Current Status

Currently, the oil and gas industry regularly drills down to 5 km,[58] so this depth can be seen as the techno-economic baseline for geothermal. The hopes for high near-term potential for geothermal are derived from the fact that significant potential opens up once deeper than 5 km. Beyond this depth the temperature of the rock reaches values suitable for exploitation in many more places on Earth, compared to the few where conventional hydrothermal is used today. Drilling is therefore the key technology at the core of unlocking advanced geothermal energy, but it is also the main contributor to overall cost (drilling time accounts for 75% of total well cost [96]). Bringing the cost of drilling down is therefore crucial and this is largely driven by faster drilling, which in the recent past has been enabled by new drill bit technologies (progress in polycrystalline diamond compact drill bits); horizontal drilling has also been decisive (known as directional drilling in the oil and gas industry).

As with most innovative cleantech solutions, what matters most for geothermal is not so much today's costs, but rather future costs, which depend on the particular learning rates of the technology (i.e. how much cheaper it gets over time, when more and more systems have been built). Recent data from EGS is promising in this respect and shows learning curves of 35% for drilling time, even exceeding expectations [96]. EGS and closed-loop geothermal have progressed to the FOAK stage, with the first offtake agreements being signed.

Superhot Rock as the Next Frontier

Box 9

Above 374 °C and 220 bar of pressure, water becomes a so-called supercritical fluid, a particular thermodynamic state that can absorb much more heat per kilogram of water. With such an increased energy density, a geothermal plant can produce much more power with the same flow rate of water. As a result, if drilling technologies can go deep enough to reach these conditions, then a "superhot" well could produce 5–10 times more electricity than a typical one operating at slightly lower temperature or pressure.

Conventional drilling technologies and materials are not yet suitable for the extreme physical conditions found at these depths, nor cost-effective (drilling cost tends to increase exponentially with depth for conventional technologies). New research and startups are emerging to address this, such as high-pulsed-power drilling, thermal-shock drilling, millimeter-wave laser drilling, percussive drilling, high-pressure water jet drilling, directional steel-shot drilling, and plasma drilling.

However, these concepts are still at a very early TRL, so the long-term pursuit of this "holy grail" of geothermal must not distract from more immediately achievable gains at less ambitious depths.

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[68] The deepest hole ever dug was around 12 km.

Potential in the EU

There is significant potential for geothermal to leverage the existing technology, capital, and labor force of the oil and gas industry. For every dollar invested in geothermal, 65–80% has a significant overlap with the skills and expertise of the oil and gas industry; therefore, a high level of knowledge transfer and productivity gains from the oil and gas industry could reduce next-gen geothermal costs by three-quarters [97].

Project InnerSpace and the IEA estimate that Europe has nearly 40 TW of technical potential for EGS below 300 USD/MWh [97], which is equivalent to 35 times Europe's current total installed electricity capacity of all types. Geothermal potential is particularly high in France, Germany, and Italy. As shown in Figure 27, at less than 2 km, the potential is very limited; it starts to become significant at 5 km, and from 7 km onward, the physical potential is almost everywhere, although the economics will still differ depending on the quality of the resource.

Over the medium to long term, the more we build geothermal, the better our understanding of the challenges and how to overcome them will be and the deeper we will be able to go, unlocking new resources. The technology can gradually improve and expand its market reach.

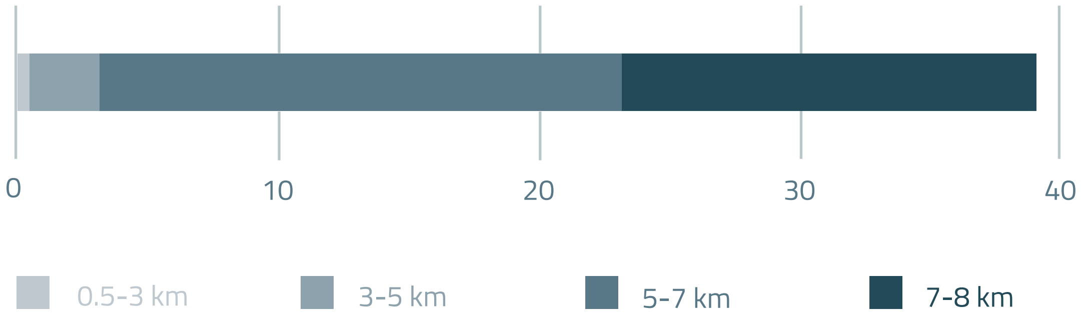


Figure 27: Total technical potential in terawatts (TW) for EGS electricity capacity by depth in Europe according to Project InnerSpace

Co-Benefits of Geothermal

Box 10

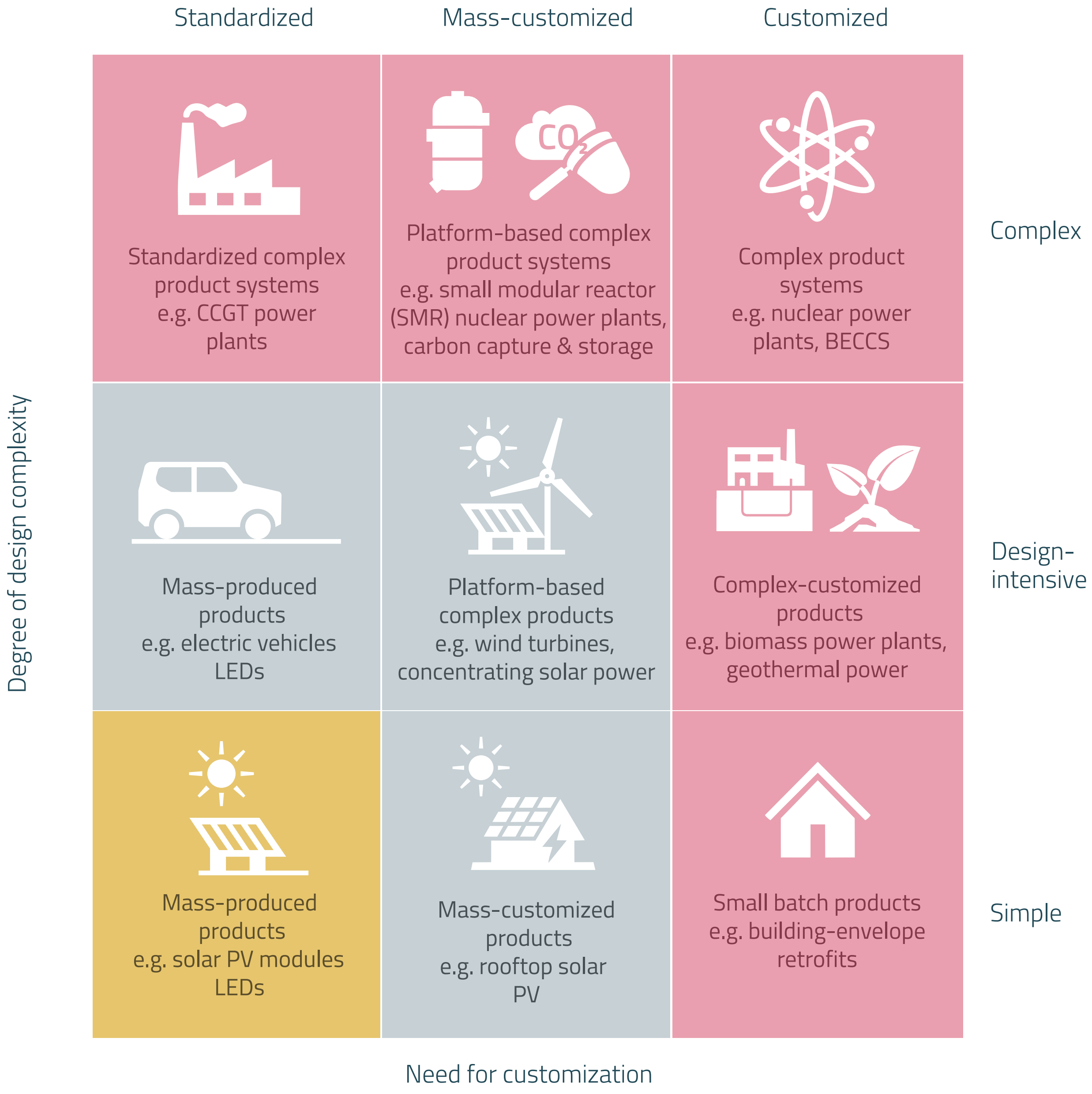
Some geothermal fluids (brines) contain lithium salts, which can be extracted for use in batteries for electric vehicles or the grid. The technology for extraction is in the demonstration phase (TRL 7/8), with proven pilot projects in Canada, France, the United States, Germany, and Argentina. Six geothermal areas across Italy, Germany, France, and the United Kingdom have high lithium concentrations in their geothermal brines; the Upper Rhine Valley between France and Germany has the potential to produce 4–6 kt/year of lithium by 2030, enough to make 1.2 million electric vehicle battery packs.

Further co-benefits (direct heating for homes and industry) are discussed further down.

Discussion

Cost

There are two ways of reducing costs: economies of scale (making each unit bigger) and learning curves, also known as Wright's Law (making more units). As shown in Figure 28, the highest learning rates tend to be found in simple, modular, and standardized technologies because these are most amenable to mass production, which helps to explain the ongoing success of solar photovoltaic and batteries. Compared to photovoltaic, wind turbines are larger and have more interlocking components, but those components still can be made in factories and assembled in a standardized and efficient manner. At the other side of the spectrum, complex and customized one-off megaprojects like hydropower or nuclear plants – in the worst case with constantly changing design requirements – have much less scope for accumulating experience fast [98], [99]; for these technologies, the path to cost reduction is typically through economies of scale. Nevertheless, as argued in the work of Flyvbjerg and others [69], the lessons of modularity for speed and cost reduction can still be at least partially transferred to these megaprojects in order to make them cheaper and faster to build.



Standardized	Mass-customized	Customized	
Standardized complex product systems e.g. CCGT power plants	Platform-based complex product systems e.g. small modular reactor (SMR) nuclear power plants, carbon capture & storage	Complex product systems e.g. nuclear power plants, BECCS	Complex
Mass-produced products e.g. electric vehicles LEDs	Platform-based complex products e.g. wind turbines, concentrating solar power	Complex-customized products e.g. biomass power plants, geothermal power	Design-intensive
Mass-produced products e.g. solar PV modules LEDs	Mass-customized products e.g. rooftop solar PV	Small batch products e.g. building-envelope retrofits	Simple

Figure 28: Characterizing energy technologies [99]

Pathways to Commercialization and Deployment

Despite the maturity of nuclear, it is in a similar position as next-generation geothermal insofar as a fresh wave of sustained demand is required to (re-)kickstart commercialization. Finding the best initial markets for this is therefore an important question that is likely to define the long-term trajectory of deployment for clean firm power.

Beyond electricity generation, geothermal and nuclear (particularly SMRs) have the important advantage that they can both also be used for direct heating, including beyond the temperature limits of current heat pumps (which top out around 150–200 °C). Applications include district heating and cooling as well as industrial heat, whose supply is currently dominated by volatile fossil fuels. Whereas district heating loads vary significantly between summer and winter, industrial processes tend to run at steady state, which means that clean firm heat sources fit industry needs well. Moreover, the direct supply of heat from nuclear or geothermal directly reduces the amount of new generating and transmission/distribution capacity that the grid would otherwise require if electrifying; given how notorious the bottleneck of grid connection and expansion issues remain for electrifying industrial heat, this is an important consideration. In sum, customers for heat might serve as a stepping stone for geothermal and nuclear SMRs to prove themselves before moving on to the more challenging market of electricity generation.

Moreover, combining industrial heating services with electricity generation might constitute a form of revenue stacking that makes the overall business case more viable. However, since heat is only transportable over short distances, the key question would become co-locating clean firm power with industrial heat demand that can tolerate some capacity being periodically reallocated to clean firm power.

Repowering Coal Power Plants with Clean Firm Power Sources

Box 11

Across Europe, coal power plants are being decommissioned in the transition to clean alternatives. However, these assets may still have a lot of value to offer: An existing grid connection (a current bottleneck in terms of permitting), a brownfield site, relevant power generation equipment (turbines, generators, etc.), and a workforce. It may therefore prove attractive, both in terms of CAPEX savings and time savings to deployment, to repower these sites with compatible clean technologies, with some commensurate adjustments. There are various grades of repowering, from the most basic (site repurposing, i.e. only the grid connection) to the most in-depth (full repowering, where nearly all the equipment is reused with minimal changes). Geothermal, nuclear, and concentrated solar power are all possible options for repowering.[69]

While the potential for full repowering in Europe is limited and mostly concentrated in Poland, there is more potential for partial repowering and site repurposing. However, the global potential of repowering is very high, especially in Asia given the continued deployment of new coal plants there. The EU can therefore play a strategic role in leading the way to showcase this technology pathway and have a spillover effect on emissions reductions globally.

On the power generation side, in order to drive costs down in the long-term, the first offtakers must be less price-sensitive and less risk-averse than average. In this respect, tech companies are a good fit, especially with the current rush to procure clean power for AI data centers. This is already happening in the United States, where leading geothermal and nuclear startups have secured their first contracts (e.g. Meta will buy 150 MW from Sage Geosystems, 1.2 GW from Oklo, and up to 5 GW from TerraPower; Google bought 115 MW from Fervo and will buy 200 MW from Commonwealth Fusion Systems) and should be emulated in Europe. Some models estimate that even a small number of commercial and industrial customers (order of magnitude[70] 3%) procuring clean firm power sources can kickstart the virtuous cycle of making these technologies more affordable and accessible (see Figure 29 [100]).

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[69] Repowering could also be done with thermal energy storage (TES) to turn these decommissioned power plants into forms of grid-scale long-duration energy storage; this is not technically a clean firm power source, however, and is therefore not within the scope of this report.

[70] By their own admission, the Riepen et al. model is more of a back-of-the-envelope calculation to give insight into the magnitude of the dynamics at play; it is not supposed to be a detailed model offering precise numbers.

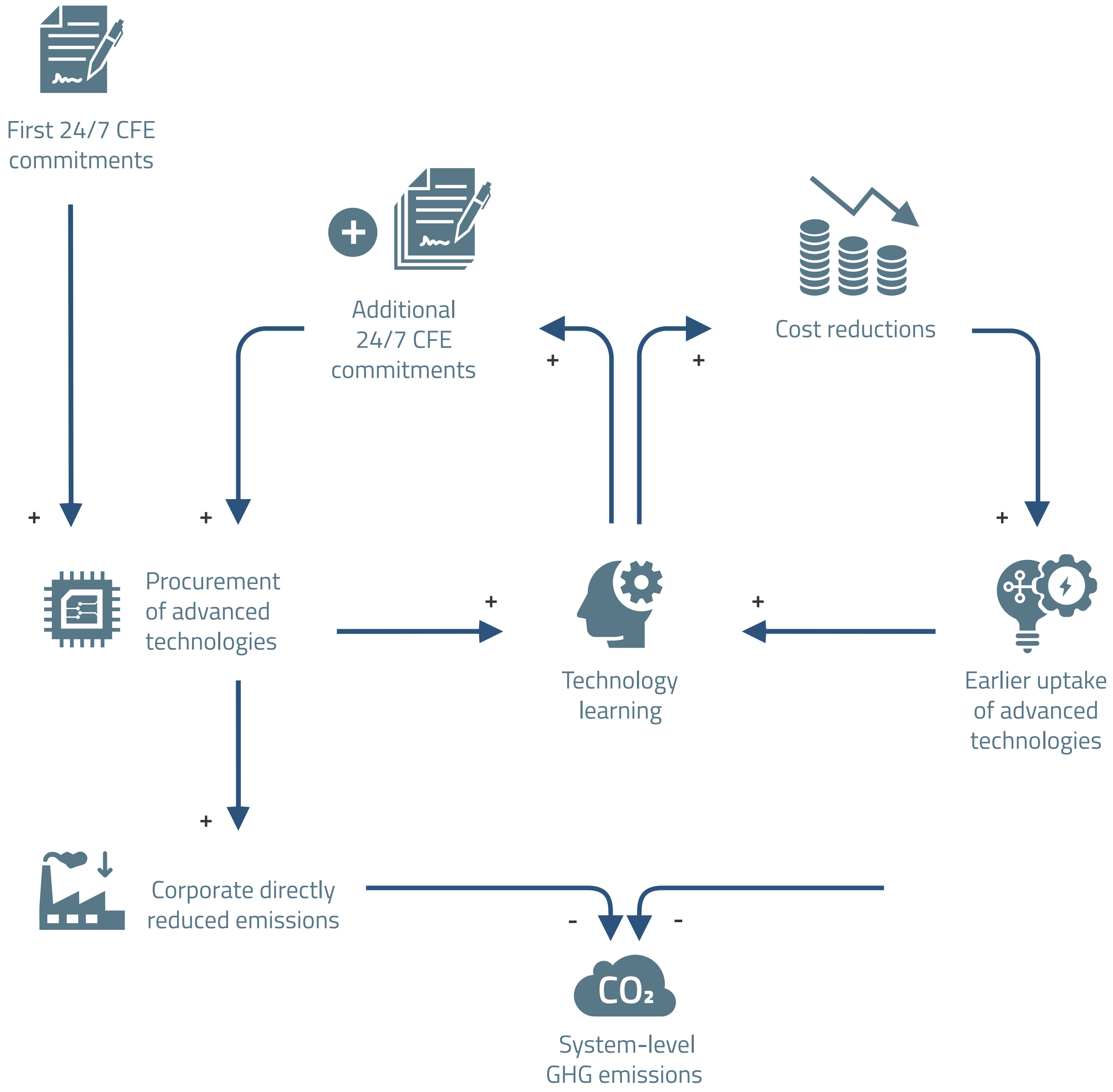

Figure 29: The virtuous cycle kicked off by procurement ("CFE" = carbon-free energy)

Policy Recommendations

Technologies do not evolve in a vacuum; they are shaped by the market forces and the regulatory environment. For early-stage technologies such as next-generation geothermal, this is all the more true, as shown by the historical trajectory of solar photovoltaic, which perfectly illustrates the crucial synergy of public support and private development. Clean firm power is needed to complement wind and solar in the energy transition, and if it is to succeed in doing so, then public policy has an essential role to play in shaping its trajectory.

The European Union stands at the confluence of energy security concerns, the quest for industrial competitiveness, and high ambitions for climate action; as such, it is uniquely positioned to support and pursue a strong agenda for clean firm power. If Europe can achieve this, then the prize goes beyond its borders and spills over into exporting these technologies to the rest of the world, further lowering global emissions while reinforcing European competitiveness. This section outlines at a high level a range of possible policies for spurring the development of clean firm power.

Recommendations Applicable to All Technologies

- **Recognize clean firm power in EU strategy:** Recognize that clean firm power and renewables are complementary, not mutually exclusive. Both should be part of a balanced, low-carbon energy mix that meets various cost structures, durations, and flexibility needs. EU decarbonization and net zero plans, including the Industrial Accelerator Act, the Clean Energy Investment Strategy, the existing National Energy and Climate Plans, and the upcoming Electrification Action Plan must explicitly include clean firm power. Diversification is key to a resilient energy system.

- The EU has adopted a target in the Renewable Energy Directive III for 5% of innovative renewables by 2030; depending on the growth of the renewable sector by then, Future Cleantech Architects estimates that this could result in 3–45 GW[71] of deployment of various new technologies. Several technologies within the concept of clean firm power, such as concentrated solar power and geothermal, fit this goal well and should be encouraged accordingly by the EU and member states within the context of this target.

- **Value firm capacity** by updating capacity mechanisms and create auctions and tenders that allow clean firm technologies to compete fairly based on carbon intensity, flexibility, and reliability. This includes hybrid models, with contracts for difference (CfD) for electricity and carbon contracts for difference (CCfD) for CO_2 avoided.

- **Encourage corporate offtakers to turn to 24/7 clean Purchase Power Agreements** with strong additionality criteria. Proposals include the Electron Bank by EnergyTag [101].

- **Attractive financing:** These are all CAPEX-heavy, infrastructure-related technologies, so the cost of financing has a major impact on the LCOE. Derisking mechanisms like blended finance models or public guarantees can also help lower perceived financial risks by investors, especially for early-stage projects. Unlocking first-of-a-kind (FOAK) financing, usually in the tens of millions and which fits neither with venture capital (equity) nor project financiers (debt), is particularly important to bridge the gap when scaling the technology from pilot/demonstration plants to commercial operation.

- Increase research, development, and demonstration support via Horizon Europe, supporting pilot projects.

- Prioritize clean firm power projects by simplifying access to grid interconnection and fast-tracking permitting.

- **Accelerate** EU-wide flexibility assessment and planning, integrating firm resources with grid and storage development.

- **Foster social acceptability** by highlighting successful projects and mitigating risks where they might exist (e.g. induced seismicity for enhanced geothermal). This will help accelerate the permitting process.

Recommendations Specific to Technologies

Biomass

- **Prioritize highest value uses of biomass** instead of low-value applications such as low-temperature heat or road transportation.

- **Build strategic reserves of biogas as a backup for seasonal shortfalls (Dunkelflaute)**, similarly to the current practice of maintaining strategic reserves of fossil fuels.

Nuclear

- **Extend the lifetime of existing plants** as much as possible, including to maintain valuable supply chains and retain critical expertise, which are difficult to rebuild once lost.

- **Reward flexibility** such that dispatchability becomes more economically attractive than pure baseload generation.

- **Standardize at EU level the chosen design** of conventional new builds. Build multiple reactors on a single site to reduce costs.

- **Accelerate building timelines** as the biggest lever to reduce cost overruns.

- **Consolidate a continental orderbook** of at least 10 GW to kickstart any new build reactor designs (especially SMR). This is crucial to sustain an effective supply chain and return to positive learning curves, as opposed to the negative learning curves of one-off reactors.

- **Reduce the cost of capital by derisking investment** and supporting low-carbon 24/7 Power Purchase Agreements that include clean firm power.

- **Scale up EU support for innovation**, especially demonstration projects for SMRs under Horizon Europe and the ETS Innovation Fund, for instance, in order to reduce costs and provide coordinated support.

- **Ensure the updated Nuclear Illustrative Programme** includes clear guidance on investment needs for SMRs and next-generation reactors.

- **Streamline and harmonize the regulatory landscape of safety assessment**[72] **across Europe** to increase market integration, and promote an EU framework for mutual recognition or alignment of licensing. This will accelerate permitting by avoiding redundant duplicative assessments, which will cut build times and costs.

  Regulatory harmonization is particularly important for SMRs to have access to a larger market. The approach to risk and environmental assessments must be proportionate, aligning safety culture with objectives of effectiveness [102].

- **Prioritize regulatory stability,** avoiding changes to requirements while projects are under construction.

- **Target new builds in locations with an existing nuclear presence** as local support is typically higher there thanks to employment and infrastructure is already in place.

- **Include nuclear in the Green Taxonomy and resolve debates over EU fund appropriation for nuclear.**

- **Build in standardized series with mature designs,** with any design updates only from series to series, not reactor to reactor within a series (like in France's Messmer Plan in the 1970s).

Geothermal

- **Characterize the resource to derisk exploration:** High-quality public data characterizing geothermal resources across Europe (i.e. geological maps of temperature and depth) can help to reduce exploration cost uncertainty, thus derisking more projects and lowering the barrier to entry for new players in the industry. In this regard, Project InnerSpace's GeoMap is a comprehensive open-source geothermal resource mapping platform and covers all of Europe with subsurface temperature, depth, as well as surface data (e.g. transmission lines). The EU and member states should integrate this into official resource planning and permitting processes and can fund country-level resolution.

- **Emulate best practices:** Several European countries have already started implementing effective policies such as geothermal resource insurance in France and Germany for derisking first projects, or permitting reforms and fiscal incentives in the Netherlands.

- **Leverage fossil capabilities for geothermal:** Compared to wind and solar, fossil fuel companies actually have all the key assets required for geothermal, namely drilling technology and workflows, capital, and trained labor.

- **Support further research and development for advanced deep drilling** techniques and testing innovative technologies.

Conclusion

Europe's electricity system is under pressure from all directions: rising demand, decarbonization targets, energy security concerns, and competitiveness issues. Abundant, homegrown, clean power generation lies at the center of this. The bulk of this power is set to come from solar photovoltaic and wind, which are growing fast and reshaping energy systems and markets around them. At higher levels of decarbonization, their intermittency must be managed through a range of flexibility tools: energy storage with batteries and long-duration energy storage, grid expansion, overbuilding, demand flexibility, and clean firm power. The economic optimum for a fully decarbonized grid is a mix of all the above, with the proportions depending on each region's specific situation.

Clean firm power designates a class of power generation technologies that deliver clean electricity in a controllable way, whether as baseload or dispatchably. Their role is not to replace variable renewables but rather to complement them, especially during periods of scarcity such as "Dunkelflaute" (a long stretch without sun or wind, a normal occurrence across Europe in the winter). In this report, clean firm power technologies include hydropower, nuclear power (whether conventional or SMRs), and next-generation geothermal (enhanced geothermal systems and closed-loop systems). While baseload operation is the default for CAPEX-heavy nuclear and geothermal, opportunities for more flexible dispatch, such as with integrated thermal storage, should be pursued where possible to enhance their profitability in an age when variable renewables often drive hourly power prices near or even below zero.

Europe's governments have a decisive role to play at this stage in shaping markets to incentivize the deployment of these technologies, whether that is a revival of mature nuclear or progressing less mature next-generation geothermal. The ambition must match the size of the prize: abundant, affordable, and reliable clean power demands a diversified portfolio deployed at a scale large enough to generate economies of scale and take advantage of learning curves. To this end, strong demand pull, streamlined and swift regulatory processes, as well as derisked and low-interest capital are all essential.

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About Future Cleantech Architects:
We are a climate innovation think tank. We exist to close the remaining innovation gaps to reach net-zero emissions by 2050. To reach this objective, we accelerate innovation in critical industries where sustainable solutions are still in very early stages.

Further Information:
Dr. Antoine Koen
Cleantech Analyst - Lead Energy Systems
antoine.koen@fcarchitects.org

Dr. Peter Ruschhaupt
Cleantech Analyst
peter.ruschhaupt@fcarchitects.org

Address: Martin-Luther-Straße 29, D – 42853 Remscheid, Germany
e-mail: mail@fcarchitects.org

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