
POLICY BRIEF

EXPERT ANALYSIS

PRACTICAL SOLUTIONS

A close-up portrait of a middle-aged man with dark, wavy hair, wearing a dark blue suit jacket, a white shirt, and a dark blue tie. He is looking slightly to the right with a neutral expression.

Britain's nuclear troubles

The unbeatable combination
of renewables and batteries

A 100% renewable energy grid

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Long-duration storage is the missing piece of UK energy policy. Pumped hydro, liquid air, flow, sodium-ion and iron-air batteries, and heat storage are all coming forward. The government's 4–6GW ambition is too timid, and a second support round should back the promising technologies left out of the first.

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SMRs are promoted as cheaper, faster, safer and cleaner than large reactors, but the evidence for these claims is thin or absent. Few have been built, those operating perform poorly, and designs keep growing in size. The UK should let others carry the risk until the claims are proven.

The unbeatable combination of renewables and batteries

DAVID TOKE | Senior Research Fellow, University of Aberdeen

BATTERY use is exploding around the world as prices crash and battery technologies improve. They are set to become the second most important source of electricity to be beaten only by the increasingly dominant growth of solar power. In fact, as can be seen in *Figure 1*, the bulk of battery capacity is going into the surging demand for Electric Vehicles (EVs). However stationary storage is rapidly increasing.

In this article I begin by looking at the expansion of lithium battery technology as a whole; then I shall zero in to look more specifically and comprehensively at the impact of the lithium battery revolution on the power sector – in particular its growing impact on electricity markets and the ability of these markets to absorb increasing penetrations of fluctuating renewable energy sources.

Lithium dominance

Figure 1 shows how production of lithium-based batteries has exploded. It began in the 1990s with the demand for laptops – which required compact, lighter batteries than could be provided by existing battery technology. Then the emergence of mobile phones as consumer devices increased demand for lithium batteries, and from

2010 onwards EVs started to become a major consumer of lithium batteries: by 2020 the demand for lithium batteries was dominated by EVs.

The decreasing costs of stationary batteries used in the power sector is thus driven by the EV market. This can be seen in *Figure 2* below. There has been talk of competition between lithium-based batteries and other technologies, e.g. sodium-based batteries, or ‘long duration’ batteries of various types. However, for the moment at least, lithium batteries continue to dominate virtually the entire market for EVs, as well as portable and stationary sources used in the power sector. Indeed, innovations in lithium battery technology, in particular the increasing use of lithium ferrous phosphate (LFP) batteries, has in-

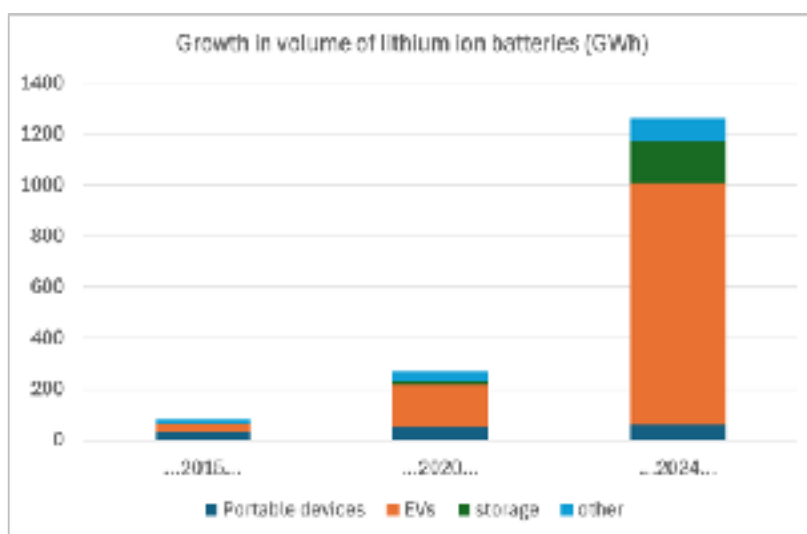


Figure 1. Source: International Energy Agency, 2026¹

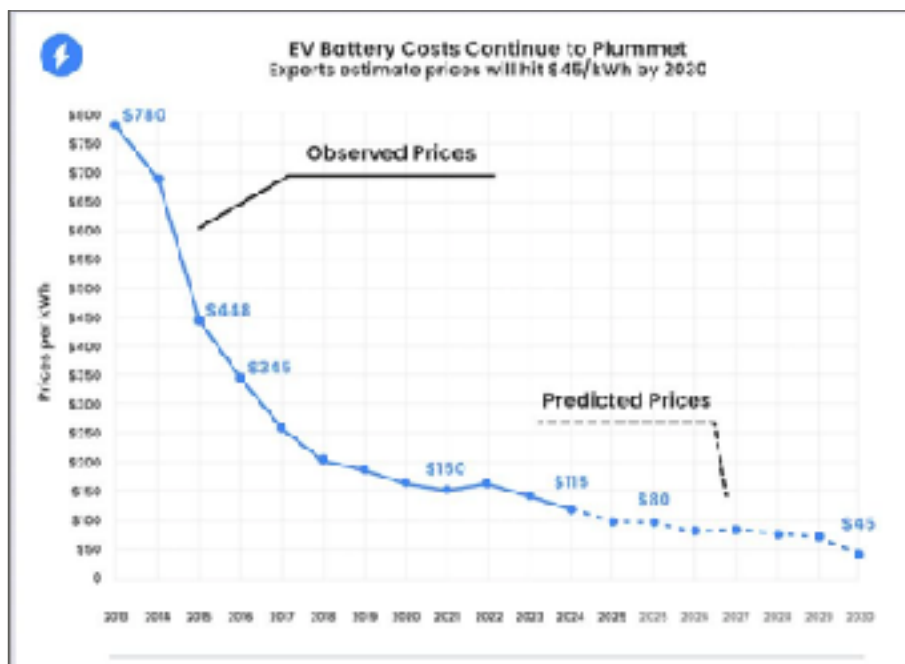


Figure 2. Source: Joe Romm, Former Acting Assistant Secretary of Efficiency and Renewables, US Federal Government.²

leading innovation in new styles of battery production, for example in LFP batteries. China's dominance in battery manufacturing, gained in particular through robot-controlled factories, is also linked to its dominance of the world market for EVs. It is important to understand the two key elements which define the power potential of batteries. One is the power that a given battery can provide, say 5MW; the other is its duration. Duration refers to the length of time that a battery can supply a given level of

creased lithium's stranglehold. Lithium is a very common element and its battery technology, via LFP, has been evolving to reduce the use of rare metals such as cobalt and nickel and at the same time reduce fire risks.

Lithium prices have edged upwards this year, but even so price rises are still small compared to the Autumn of 2022 when prices peaked at over three times the current world market price. Nevertheless,

the dominant Chinese battery company CATL has started producing sodium-based batteries which promise to use more common ingredients for an efficient alternative that is especially suitable for stationary batteries.

Around three quarters of the world's battery production comes from China. China is

power. For instance, if a 5MW battery can store 10MWh of electricity in total, then it will have a 'duration' of two hours. The longer duration a battery is designed to last, the

more expensive it is to produce. Certainly, governments have promoted innovation in alternative, longer duration batteries (i.e. more than, say, eight hours). That is a worthy thing to do. However, there is no technical reason why lithium batteries could

There is no technical reason why lithium batteries could not be used in much longer duration batteries that are routinely used today in electricity markets.

not be used in much longer duration batteries that are routinely used today in electricity markets. It is only recently that battery durations for grid purposes have often been longer than two hours. The only reason that they are not is that power markets do not yet demand this. However, as wind and solar penetrations increase, this is likely to change.

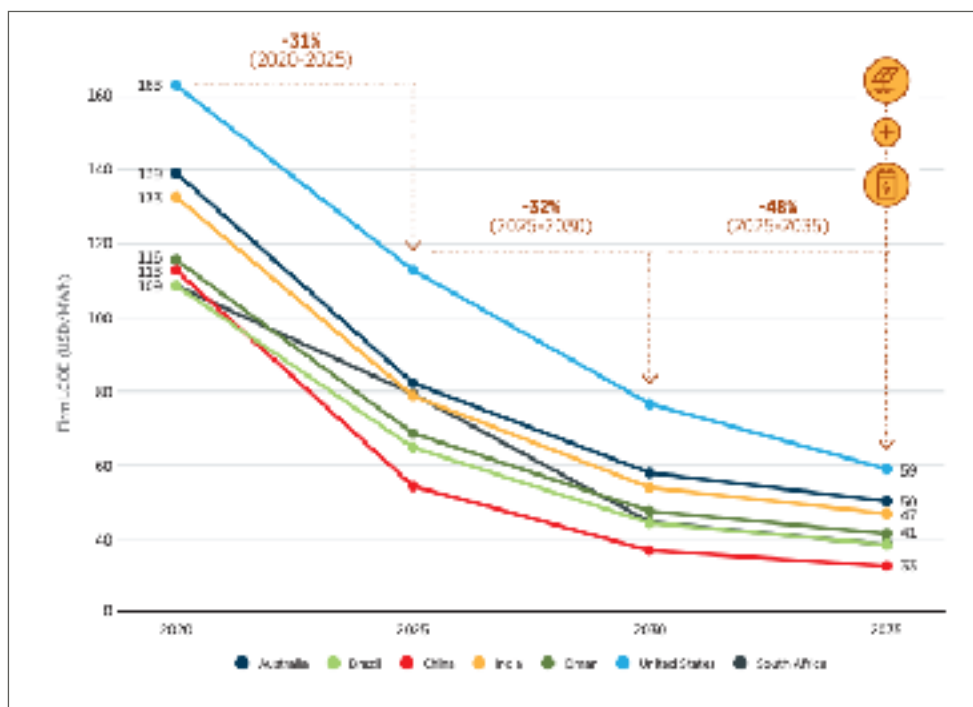


Figure 3. Firm LCOE trajectory for solar PV and BESS at 95% reliability, 2025-2035. Source: IRENA (2026)³

There may be economic advantages for developing (non-lithium) battery systems that can deliver power for over a few hours duration. However, the cheapness of non-lithium long duration battery technologies is yet to be demonstrated. Of course, other battery technologies may find niches to which they are better adapted compared to lithium-based ones. This whole discussion should not be confused with a discussion about inter-seasonal or inter-annual storage vectors (e.g. hydrogen). Such a topic is rather different from the intra-day batteries that are the focus of this article.

Absorbing wind and solar generation

The wind does not blow and the sun does not shine all the time. However, batteries can make up for most – and in some parts of the world all – of this gap. This used to be a crazy idea because solar PV and wind power and batteries were expensive. But now wind and especially solar costs have dropped dramati-

cally – to a small fraction of the cost 30 or 40 years ago. Batteries used to be expensive, short-lived, and based on heavy lead acid technology. Now things have changed radically. In many parts the world, solar plus lithium-based batteries are the cheapest mainstream electricity source. You can see the trajectory in *Figure 3* from a recent report from the International Renewable Energy Agency,

which charts spectacular reductions in cost in the very recent past, specifically highlighting declines in the US of 31 per cent from 2020-25, with projected declines of a further 32 per cent from 2025 to 2030 and 48 per cent from 2025 to 2035 in the US market.

Solar PV is the cheapest source of electricity even in the UK. It came in as cheaper than its next competitor, onshore wind, in the most recent competition in bidding for UK Government backed contracts for renewable energy (AR7a). In the UK, as elsewhere, batteries allied to renewables are acting as competition for gas fired power plant – competition that will reduce power prices. In Northern states like the UK, wind might still be dominant compared to solar PV because of the need to provide a more even level of electricity production in the winter (when there is in any case more wind production).

As the penetration of fluctuating wind and solar sources increases, gas is used less and less while declining battery prices allow bat-

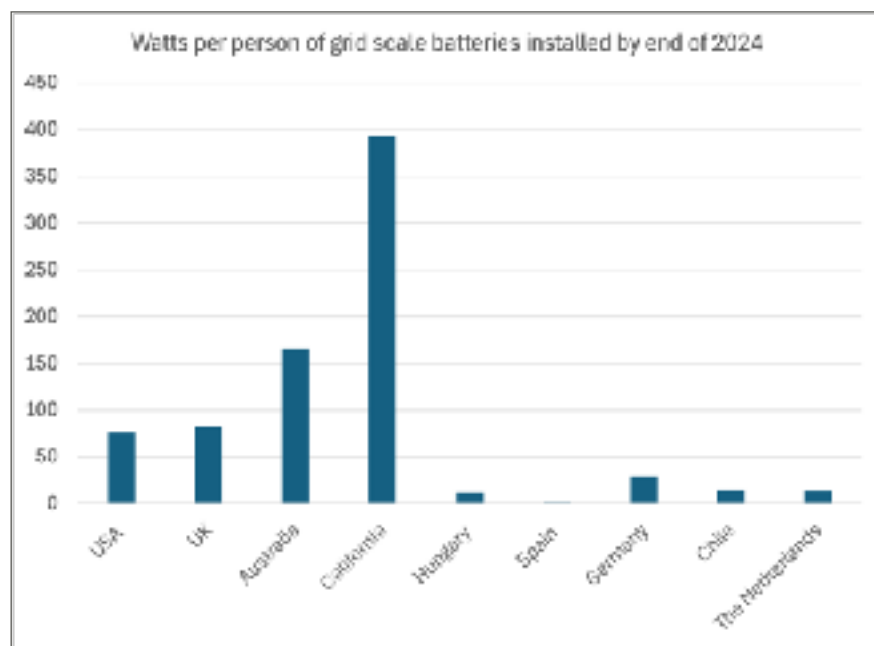


Figure 4. Sources: 2025 Energy Institute Statistical Review of World Energy (EIS-RWE); California Energy Storage System Survey 2025 and press reports for Hungary, The Netherlands and Spain.

teries to substitute for gas-fired peak generating capacity. Indeed, in the UK the amount of time that natural gas sets the wholesale electricity price is declining, though gas still sets the price for around three quarters of the time this is down from over 90 per cent of the time just five years ago.

Very large amounts of battery capacity are waiting to be connected to the UK grid. However, we can already see the big impact that batteries are having in balancing solar PV in places like California and Australia. In these places there is a lot of solar PV already installed

and an increasing amount of battery capacity. As can be seen in *Figure 4*, California and Australia have the highest installation rates so far on the basis of capacity per person.

California, and to a lesser extent Australia, are ahead of other countries in developing battery capacity partly because of the tremendous growth in solar PV generation during the daytime. Although this coincides with peak demands for air conditioning it still leaves a problem of excess supply during the daytime compared to de-

mand.

In California the Government, advised by its California Energy Commission, induced the big energy utilities to invest in grid-scale

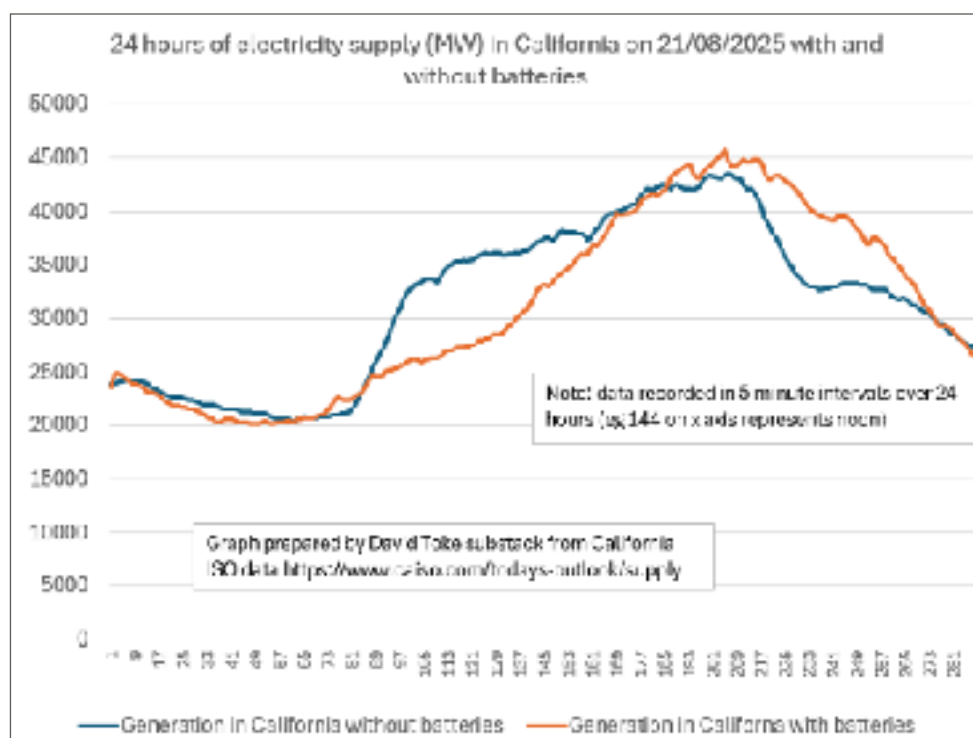


Figure 5. Source: California Independent System Operator (CAISO).

batteries. The impact of increasing levels of batteries can be seen in *Figure 5*. Two lines are shown: generation with batteries and generation without batteries. The ‘without batteries’ line shows what would have happened without the batteries, i.e. it shows the electricity generation (including large amounts of solar PV) as it occurs. The

‘with batteries’ line shows the power that was sent to consumers. As can be seen, the existence of batteries meant that, in effect, much of the daytime generation was shifted to the evening. The amount of generation being shifted is increasing rapidly and both installed solar PV and battery capacity increases. If it was not for the batteries, increasing amounts of solar PV generation would have to be curtailed.

Indeed, there is an increasing problem in power markets. As solar PV generation increases, focussed as it is on the sunniest parts of the day, more and more is excess to electricity demand. This reduces what are called ‘capture prices’ – the monetary value of the output from solar PV – and the value of solar PV generation declines. The excess generation problem can be ameliorated by utilities installing large batteries and the solar PV generators themselves can capture more value for the

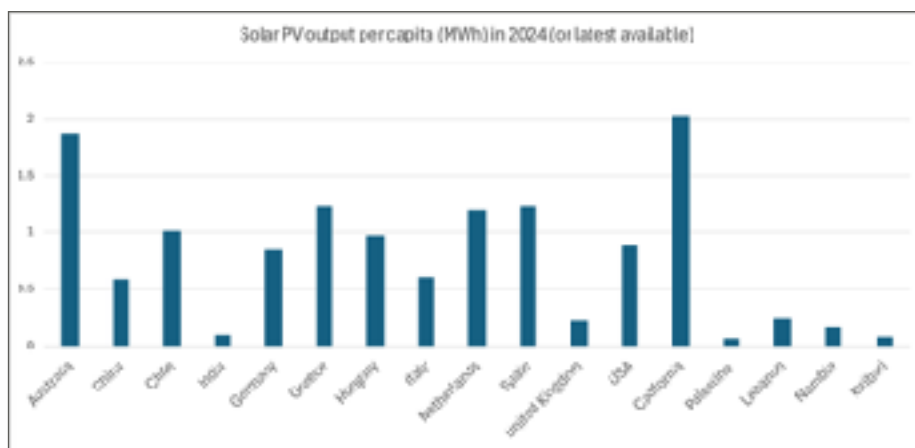


Figure 6. Source: 2025 Energy Institute Statistical Review of World Energy (EISRW), and Our World in Data. (Note: Data on Palestine and Kiribati is from 2022 and Lebanon and Namibia is from 2023.)

otherwise excess (and low-value) generation by co-locating the solar farms with batteries. As solar generation increases as a proportion of total electricity generation, this is becoming the norm in many places.

It needs to be pointed out, however, that there is a mismatch between the relative proportions of electricity production provided by solar PV and the level of battery installation in different countries. Unlike California and Australia countries, such as Spain and

Germany with high proportions of solar PV production are relatively lacking in battery installations. These latter countries will have to increase (and to an extent already are increasing) their battery installations in order to keep down the amount of low

value solar generation. This contrast can be seen by comparing *Figure 4* shown earlier with *Figure 6*. The UK is building up its battery capacity by around 2GW a year, with

The excess generation problem can be ameliorated by utilities installing large batteries and the solar PV generators can capture more value by co-locating the solar farms with batteries.

around 7GW in place at the end of 2025. However, this rate of growth is well behind the National Electricity System Operator (NESO) target of 23-27GW of Battery Energy Storage System (BESS) by 2030.

In addition, the UK Government is promoting 'long duration energy storage' (LDES) through a cap and floor incentive system. There is a target of 4-7GW of LDES by 2030. There is no shortage of proposed projects – over 60GW of battery projects have planning consent. The big dampener on rapid growth are grid connection bottlenecks. NESO has introduced a method of speeding deployment by shortening grid connection queues so that only 'ready to go' projects are at the front of the grid connection queue.

The UK Government says that the reforms are cutting out large proportions of 'un-ready' generation and storage which are acting as connection blockers. However, this reform may not be enough to meet the targets. One measure that will create greater income streams for batteries is simply to increase the roll-out of wind and solar projects. This is because the more the electricity system relies on fluctuating generation the more there will be a difference between wholesale prices. This difference in prices is between the high wholesale prices in those half-hours when there is a shortage of wind and sun and, on the other hand, low (or, even negative) prices when there is an abundance of fluctuating renewables. Hence the opportunities for 'arbitrage' will increase as the proportion of electricity from fluctuating renewables increases.

Markets for batteries

For the most part, batteries in the electricity sector have been developing from market pressures rather than government inducements. That having been said, batteries are taking advantage of incentives that are on offer to provide reserve source of electricity. These 'capacity markets' are where companies are given payments to guarantee provision of capacity if called upon to do so. Until recently, capacity markets were entirely taken up by conventional (mostly gas-fired) generation.

The market that has seen the main drive for the initial installation of batteries in the

**Batteries can provide frequency
response services very quickly
indeed.**

electricity sector is the frequency response market. Traditionally fast response markets have been populated by flexible, usually gas-fired, fossil fuel plant.

These can come on stream at a moment's notice to ensure that frequency of electricity transmission is kept stable within regulated boundaries. The electricity system operators will buy frequency response services (and other 'ancillary' services) off generators according to who can supply them cheapest at any given time. However, in recent years batteries have increasingly dominated such markets in the UK because batteries can provide frequency response services very quickly indeed.

A third market that has been a growing market for batteries consists of balancing mechanisms. These are used by system operators to provide supplies of electricity when there are gaps in between registered 'wholesale' supplies of electricity and the

amount that is being demanded in any half hour in the national electricity system. Balancing mechanisms can become more important as fluctuating electricity supplies become more important for national grids. That is because predictions of fluctuating renewable energy sources are not perfect.

However, an even bigger growing market for batteries is the so-called ‘arbitrage’ market. Arbitrage means that battery owners absorb or buy in power when wholesale power prices are low. Then they sell the power that they have stored in the batteries when wholesale power prices are high.

Opportunities for ‘arbitrage’ trading expand generally as the proportion of electricity produced by wind and solar PV increases. Not only this, but the duration of batteries that are installed also increase since there will be more demand for battery services of a longer duration. As the proportion of generation from wind and solar power increases, then the likelihood that such generation will exceed demand also increases. This implies that there will be more and more excess renewable energy that is available for storage. Hence, ‘arbitrage’ will become the largest market for grid-connected batteries as the proportion of total electricity that is fluctuating increases. Indeed, the ‘duration’ of batteries installed is gradually increasing as the use of batteries shifts from being mainly short-term ‘frequency response’ and ‘balancing’ to longer lasting ‘arbitrage’.

Conclusion

Use of batteries in the power sector is growing very fast. However, this is coming largely on the back of the rapid roll-out of Electric Vehicles which is providing the largest share of manufacturing battery pro-

duction and driving down the cost of producing each unit of battery power.

The expansion of the use of batteries in the power sector will march forward with the expansion of the proportion of electricity that comes from fluctuating renewable energy sources, mostly wind and solar. Renewable energy sources and batteries are an unbeatable combination that will sweep most other electricity generation off the map across the world. This will allow global energy transition to move forward. Its speed, ultimately, will depend on electrification of energy sectors and the rapid application of technologies such as EVs and heat pumps.

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David Toke is director of 100percentrenewableuk Ltd and also author of the 'Energy Revolutions' substack blog. He has had over 50 papers published in refereed journals as well as nine books and over 3,500 citations according to 'ResearchGate'.

He has engaged in research programmes funded by the ESRC, the EU, the Leverhulme Trust, the British Academy, and Scottish Insight. In 2023 he became Principal Investigator for the ESRC-funded project 'Solar Power in the UK – Planning for a Sustainable Future'.

Reforming British Electricity Transmission to lower costs

DAVID NEWBERY | Emeritus Professor, Faculty of Economics, University of Cambridge

THE Government's ambitious plans for decarbonising electricity will require a massive investment in transmission as new renewable power is located often far from a grid designed in the 1960s for conventional power stations. The National Energy System Operator, NESO, is responsible for planning this expansion. Its Beyond 2030 report recommends around £58 billion in direct investment for offshore and onshore network upgrades. Clearly considerable investment is needed, but it is time to query the very high cost of at least some of the offshore networks. NESO is charged to minimise total system cost – including the cost of investing in and operating generation as well as the transmission to deliver it to market. This *Policy Brief* argues that better signals to guide new onshore wind investments to lower cost locations and better transmission choices and routes could save £ billions.

It is worth asking why NESO is contemplating such an expensive solution to the problem of exporting wind power from Scotland to England. The plans date back to when National Grid was responsible for planning as well as operating the grid. As a regulated

monopoly it could earn the allowed rate of return on all approved new investments, and also on the high cost of the extensive planning and consultation before investing. As such it had an incentive to maximise its amount of investment and planning, provided only it could convince the regulator, Ofgem. Although Ofgem asks engineering consultants to check the plausibility of the submitted costs, and has penalised inefficient delivery, it is less capable of judging

Ofgem and NESO should reconsider the Beyond 2030 study.

whether there are cheaper solutions available. This brief is in part a plea that Ofgem and now NESO (separated from National Grid to remove such conflicts of interest) should reconsider the Beyond 2030 study. The

remaining concern is that many of the new staff of NESO may come from National Grid and continue to reflect its culture, particularly if they have been involved in the earlier planning of network expansion.

It is not clear how much of the £58 billion will be to connect offshore windfarms and how much is part of the Transmission Owners' investment needs, as NESO's Beyond 2030 report is lamentably silent on individual costs. Offshore windfarms build their own

connections that are then auctioned to Offshore Transmission Owners (OF-TOs), who then charge the windfarm a per MWh charge for 20 years. That charge is part of the cost to be covered in the Contracts for Difference (CfD) auctions and appears as an energy charge. For example, the 2026 auction round cleared at a price of £91.20/MWh (2024 prices), which includes the cost of delivery to the on-shore main integrated transmission system. Suppose that £30 billion (about half) is offshore links to transport power from Scotland to England, and suppose that operation and maintenance (O&M) costs are 20% of the total, so the amount to be amortized is £36 billion. The annual cost of amortizing this amount is roughly £1.8 billion. Projected 2030 electricity consumption is 287 TWh so this would add over £6/MWh to electricity bills for the next 40 years. This of course assumes that projects are built on time and to budget. The only subsea link commissioned to date, the Western Bootstrap, went massively over budget and was eventually fully operational over four years late and after fines imposed by Ofgem.

Reducing the cost of transmission

There are two ways of reducing transmission costs, and both are needed.

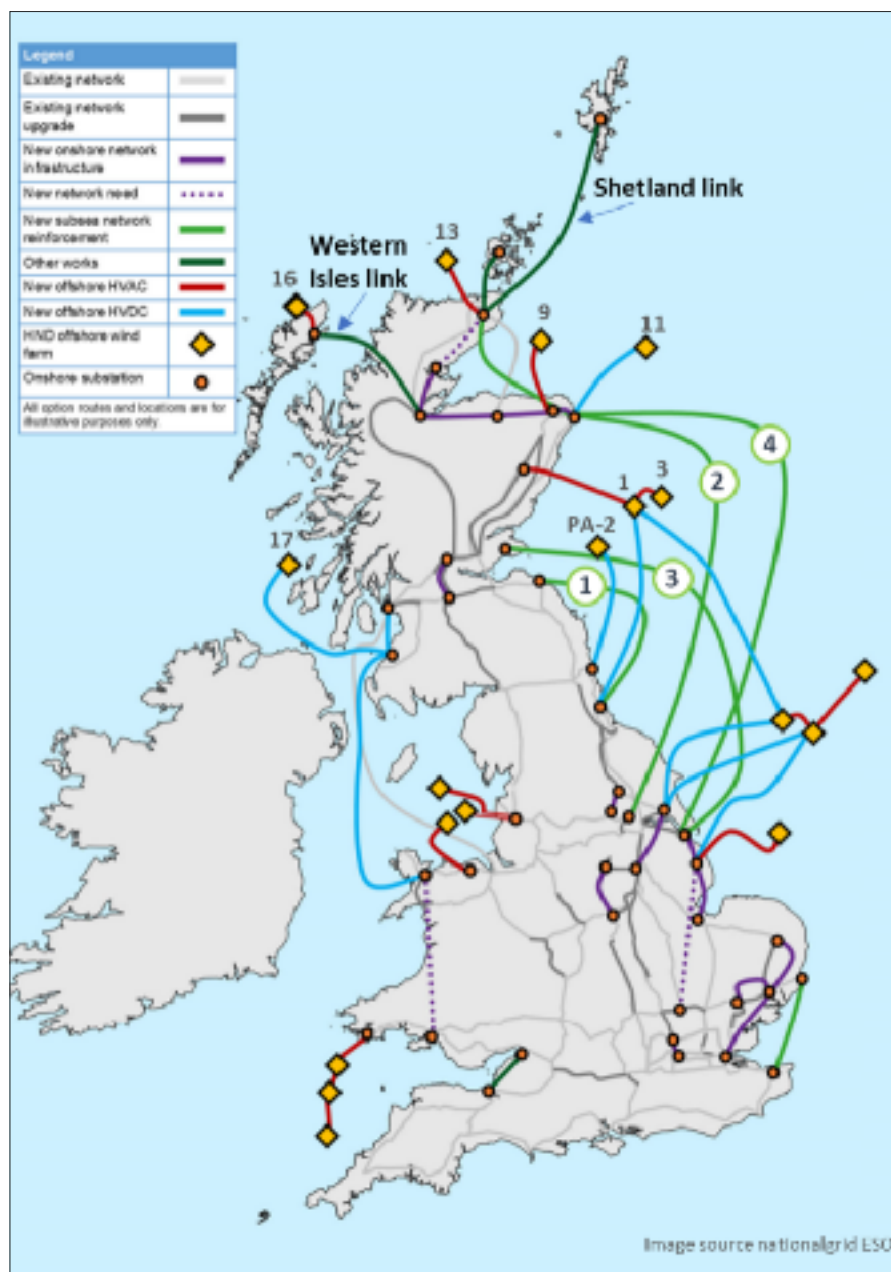
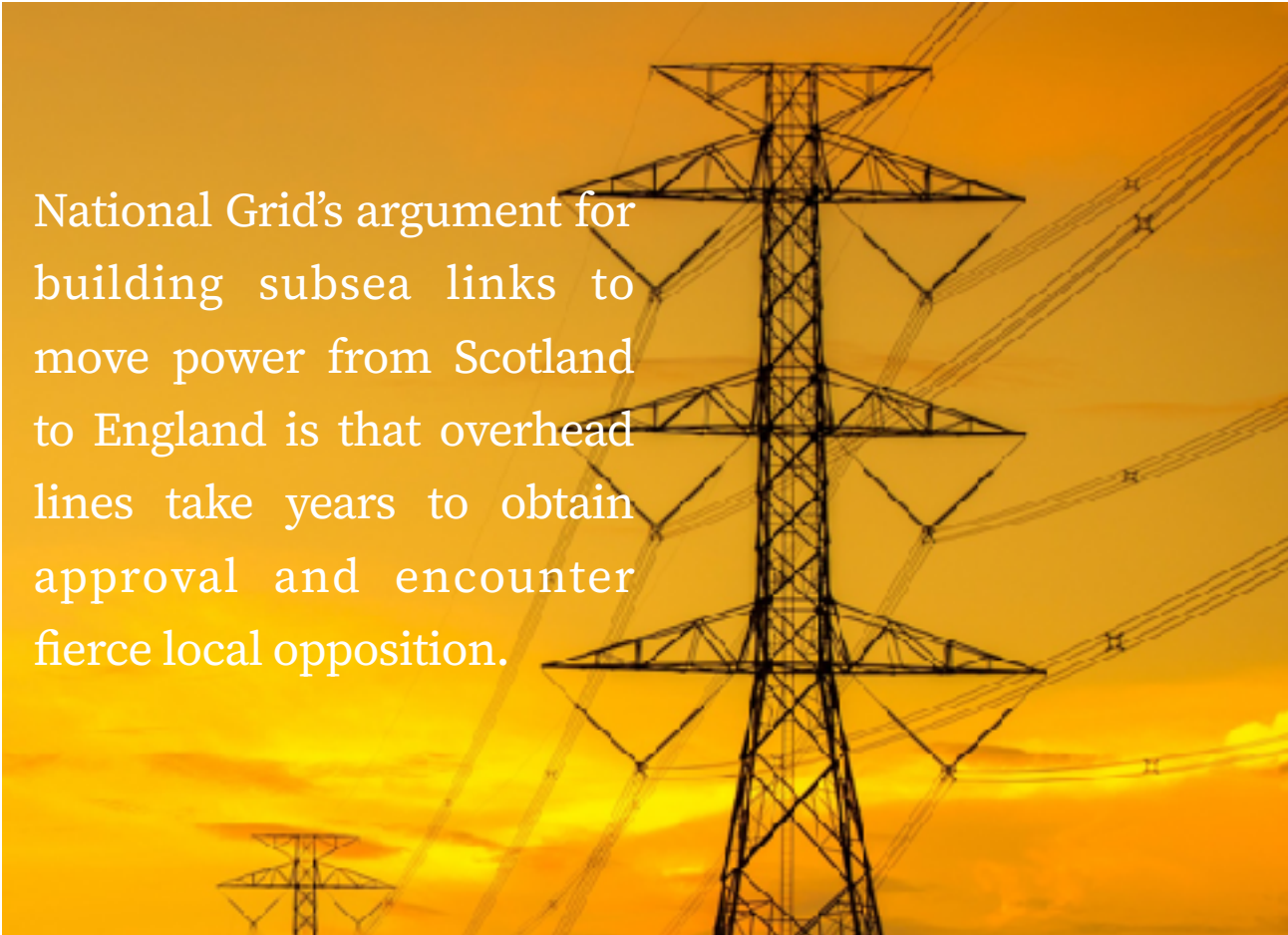


Figure 1. Planned transmission upgrades. NESO, 2024, Figure 1, page 7.

Onshore rather than offshore transmission

The first is to build onshore rather than offshore links between Scotland and England. The relatively incomplete data in Mott MacDonald's 2025 report on electricity transmission suggests that subsea High Voltage Direct Current (HVDC) lines can be more than eight times the cost of onshore High Voltage Alternating Current (HVAC) lines of similar size (2GW), with larger capacity onshore lines considerably cheaper per MWkm (i.e. per MW



National Grid's argument for building subsea links to move power from Scotland to England is that overhead lines take years to obtain approval and encounter fierce local opposition.

of capacity per km of length). To take a more relevant example, the subsea Scotland England Green Link 2 (SEGL 2) project, 440 km, 2GW, is projected to cost £4.3 billion or £130.29/kWyr (amortized at 5.05% with 20% O&M, at 2024 prices). The current Generation-Transmission Use of System (G-TNUoS) charge, which is intended to measure the long-run marginal cost of expanding the network, is £27.58/kWyr between the entry and exit point of SEGL 2; this is 6.2 times higher than the current use of system (G-TNUoS) charge.

In addition to the initial cost, subsea cables have a high failure rate, and it is often time-consuming and expensive to locate and repair the fault. Repair costs are reported to be £10m-£100m per incident. For High Voltage Direct Current (HVDC) subsea interconnectors, the European Network of Transmission

System Operators for Electricity (ENTSO-E) reported last year that the “percentage of unavailable technical capacity (EU) of all links in 2024 was 11%”. Again, repairs can be lengthy: the EstLink 2 sea cable was damaged in January 2024 and took seven months to repair. In periods of increasing geopolitical tension security issues may become increasingly important too.

National Grid's argument for building subsea links to move power from Scotland to England is that overhead lines take years to obtain approval and encounter fierce local opposition. As noted, National Grid had an incentive to argue for asset-heavy solutions, and one would hope that NESO is more sceptical of this argument. There would seem to be two solutions worth exploring. The first is to run an additional double circuit set of pylons along the way-leaves of the current

North-South main transmission lines. Indeed, the methodology for setting Generation-Transmission Use of System charges assumes that existing lines can be incrementally expanded each year, demonstrably not happening at present, but clearly worth considering. The visual intrusion of adding a line to one already there would seem to be minimal, and there is little evidence of strong protests against the existing lines.

The second solution is to install HVDC cables from a suitable site in Scotland down to the Midlands. Long distance HVDC is cheaper than conventional alternating current (AC) lines above distances of 500-700 km because of much reduced

power losses. Thus the lifetime cost of a 700km 8GW HVDC cable is 53% of the conventional high voltage alternating current (HVAC) overhead line, a dramatic saving. HVDC lines can be carried on lower pylons, so if following existing way-leaves would be even less intrusive. According to Mott MacDonald, HVDC onshore is “Not currently used in GB but common-place in other countries. Multiple such links are currently under construction in Germany to provide a link between the North of the country which has significant renewable generation, and the South which has high demand.”

Improving locational signals for new wind-farms

At present onshore windfarms pay less than the full Generation-Transmission Use of Sys-

tem charge as they impose less stress on the network. A windfarm with a 34% capacity factor (CF) connected in Argyll in Scotland (a windy location) would pay £23.71/kWyr. (77% of the full charge) while one connected in the Midlands and East Anglia would be paid £0.10/kWyr (if delivering in winter peak hours, otherwise zero). At the assumed 34% capacity factor the difference between the two translates to £7.96/MWh, a substantial incentive to locate wind farms in low charge

zones instead of zones distant from demand.

To put this figure into context, the February 2026 Auction Round 7a cleared at £72.24/MWh for onshore wind. A wind farm in Argyll would earn a gross income of £64.28/MWh, compared to the full

£72.24/MWh in East Anglia. The Argyll windfarm would need to have a 38.2% capacity factor to earn the same gross income as a 34% capacity factor East Anglian wind farm. This is hardly a deterrent to locating in Scotland given its better wind conditions.

This assumes that current overhead lines can be immediately expanded at the same cost as existing lines, but the reason for the subsea connections is because this is thought impossible. If new windfarms had to pay the cost of using SEGL 2 the annual charge would be 71% of £130.29 or £92.50/kWyr and £21.73/MWh (at 48.6% capacity factor, CF). This would be the CF needed to deliver the same gross income as an East Anglian windfarm with a 34% CF.

Faced with the correct long-run marginal cost of expanding transmission via subsea

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windfarms would avoid Scotland,
and locate nearer to demand.**

links, windfarms would avoid Scotland, forgo the apparently higher capacity factor, and locate nearer to demand with a lower capacity factor but also a lower total system cost. If enough windfarms choose to do this, and until onshore lines can be built, the case for SEGL 2 (and the other subsea links) would disappear.

The reform needed to deliver this lower system cost would be to grandfather all existing connections (i.e. continue to pay according to the published methodology) but offer new connections at the new forward-looking marginal cost (i.e. the cost of the next line). This would be with a contract at that price for e.g. 20 years, like the current offshore transmission owner (OFTO) charges for offshore windfarms. The benefit would be avoiding the very high curtailment rates currently experienced in Scotland as a result of constraints on the transmission system – in recent cases over 50%. If a windfarm is curtailed 50% of its potential output, its costs per unit of output are doubled, confirming that locating in such constrained areas is costly. Existing generators would have no reason to complain if this reform were introduced for all new as yet not consented connections. Almost all revenue for transmission is already connected from load (i.e. consumers), which can readily accommodate this reform without undermining regulated transmission revenue.

If only a limited export capacity at any node on the grid is currently available, a further reform would be to offer only that

amount firm (i.e. with compensation for curtailment below this amount), with no compensation if curtailed, and with priority curtailment – last connected first curtailed. This has been proposed for the island of Ireland by Eirgrid, which offers a non-firm connection until the link is reinforced or after five years, whichever is sooner. The agreement could be attached to a grid contract when the line becomes available that reflects the (suitably shared) amortized deep connection charge. A similar contract is offered to variable renewable energy projects (VRE) connecting to GB distribution

networks, a result of an innovation competition initiative to accelerate connections. Developers are offered either a firm contract at the deep connection cost, or an existing cheaper option but

subject to a capped level of curtailment.

Ofgem will need to ensure that Generation-Transmission Use of System (G-TNUoS) charges reflect the true cost of new connections.

Conclusions

Current plans that have their origin with asset-hungry National Grid propose to deal with the massive expansion of renewable electricity in distant location with a massive and unnecessarily costly expansion of subsea transmission links. If NESO is to fulfil its duty to minimise total system cost (as the former vertically integrated and state-owned Central Electricity Generating Board did with its spatial planning) it will need to revisit its Beyond 2030 report while Ofgem will need to ensure that Generation-Transmission Use of System (G-TNUoS) charges reflect the true cost of new connections.

The Government is onto a false trail on the UK's nuclear troubles

STEPHEN THOMAS | Emeritus Professor, University of Greenwich

THERE is a pervasive narrative that the UK is uniquely poor at building nuclear power plants in terms of costs and construction times. The dominant cause of these delays and high costs is claimed to be planning and regulatory processes which are slow and obstructive. The Regulatory Taskforce and Prime Minister Sir Keir Starmer have been particularly prominent in expressing these views.

When he announced the setting up of the regulatory taskforce the Prime Minister stated: “For too long, blockers have had the upper hand in legal challenges – using our court processes to frustrate growth. We’re putting an end to this challenge culture by taking on the NIMBYs and a broken system that has slowed down our progress as a nation.” This was a clear sign to the Taskforce of the conclusions he expected them to come to.

The Regulatory Taskforce stated that the UK “has become the most expensive place in the world to build nuclear projects.” And that the planning and regulatory system was “not fit for purpose”.

What has been less reported, and which has seen little comment from the government are the highly critical comments on the government’s role and that of industry:

Underlying laws and regulations prioritize process over outcomes, leading to time-consuming delays and suboptimal decisions;

Government departments are often slow and indecisive in their roles as policy-makers and regulators, failing to provide clear direction;

The near-monopolistic status of much of the industry provides weak financial incentives to reduce costs or challenge disproportionate regulatory decisions.

What is missing from the Government’s and the Taskforce’s conclusions is any analytical evidence to back up their conclusion that regulation and planning processes need to be deregulated.

Why have the UK nuclear projects announced since 2006 failed?

There have been six large reactor projects announced since Tony Blair stated that nuclear power was “back on the agenda with a vengeance” in May 2006. These were:

The Hinkley Point C and Sizewell C projects each comprising two French-designed European Pressurised Reactors (EPRs) to be owned by consortia comprising EDF and a Chinese company, China General Nuclear (CGN);



The Bradwell project comprising two Chinese design HPR1000s to be owned by CGN with EDF as a minority partner;

The Wylfa and Oldbury projects each expected to comprise two Hitachi Advanced Boiling Water Reactors (ABWRs) to be owned by a consortium, Horizon, of several large European utilities;

The Moorside project comprising three Westinghouse AP1000s to be owned by the two largest German utilities.

All were expected to be built using the financial model implemented with the Hinkley Point C project, although this was never formally stated, and all were expected to be in operation by 2030 except Bradwell B which never had a forecast completion date.

Hinkley Point C

A Final Investment Decision (FID) for Hinkley Point C was taken in October 2016 nine years after EDF announced its intention to pursue this project. In 2007, EDF claimed the first power from the plant would be in 2017. By 2013, when initial agreement on the deal was announced project completion was

expected for 2023. By 2016, it was expected the second reactor would be completed before the end of 2025 at a cost of £18bn (in 2015 money). The regulatory process introduced by the Blair government in 2007, Generic Design Assessment, was expected to take four years. This target would have been achieved with the European Pressurised Reactor (EPR) but the process was extended by a year to 2012 to allow the implica-

tions of the Fukushima disaster for Hinkley and the other UK reactors to be considered. The main cause of the delays in reaching the FID appears to be government and EDF negotiating on the deal and EDF trying to bring in other investors so its stake was less than 50%.

The latest forecast from January 2024 is that the second unit would be completed as late as 2032 at a cost of up to £35bn (in 2015 money). A key element to the deal was that the power purchase price was set in real terms for the duration of the 35-year contract at £92.5/MWh (in 2012 money) with EDF responsible for paying for any delays and cost overruns. The cost overruns resulted in them having to write-off €12.9bn of their investment in Hinkley in 2023. This was a major factor in EDF refusing to go ahead with Sizewell C using the same financial model.

Sizewell C

The deal to take this project to Final Investment Decision (FID) was signed at the same time as the Hinkley deal but by 2018 EDF had made it clear it would not proceed with the

project on comparable terms to those of Hinkley Point C. In part this was due to the risk of a fixed power purchase price outlined above but EDF would also have struggled to find the cash to finance its expected 80% share of the equity. EDF promoted the Regulated Asset Base (RAB) model as an alternative with EDF not expected to be a significant equity partner. It was not till 2022 that the government had passed the legislation needed to use this model. The next three years were largely spent by the government

Three years were spent trying to get investors but government was only able to cover about 40% of the cost from sources other than its own and EDF.

trying to persuade investors to invest but government was only able to cover about 40% of the cost from sources other than its own and EDF. The central estimate for completion is 2039, a lead-time from FID of five years more than was forecast for Hinkley Point C in 2016. The forecast cost is about 70% more in real terms than the estimated cost of Hinkley Point C was at FID. How far these increases are due to the estimates being more realistic and how far they are to the lead-time and real cost having gone up in the past decade will not be known until Sizewell C is complete. As with Hinkley, delays at Sizewell in getting to FID were not caused by regulatory and planning delays. Any that arose were not on the critical path. The delays were largely down to financing difficulties and government processes.

Bradwell B

The third project agreed in 2016 with the EDF/CGN consortium, this time led by CGN

(80%), was for two Chinese design reactors at Bradwell. The Office for Nuclear Regulation (ONR) successfully completed its Generic Design Assessment (GDA) on the design in 2022. Little other progress was made with the project and a Development Consent Order (planning permission) was not applied for.

The government effectively vetoed it in 2021 because of the national security issues raised by CGN's involvement although the project has yet to be formally abandoned.

"As with Hinkley, delays at Sizewell C in getting to Final In-

vestment Decision were not caused by regulatory and planning delays. Any that arose were not on the critical path. The delays were largely down to financing difficulties and government processes."

Wylfa/Oldbury

The consortium of European utilities, Horizon, which set up these two projects, sold the venture in 2013 to the Japanese reactor vendor, Hitachi. The utilities withdrew because the impact of the Fukushima disaster made new nuclear projects problematic and because the opening to competition of electricity markets meant utilities could no longer justify building economically risky and probably uneconomic facilities. Hitachi does not have the financial capability to finance nuclear power plants, and it hoped it would be able to sell on the projects when they were further advanced but still using Hitachi's reactors. In 2019, the Wylfa venture collapsed because of a lack of investors

despite the UK government offering to take a 30% equity stake and providing all the finance. Little progress had been made with the Oldbury project which was also abandoned.

Moorside

In 2012, the NuGen venture by two German utilities was sold to Toshiba, the then owner of Westinghouse reactor vendor, because of the Fukushima disaster and the confirmation of the nuclear phase-out policy in Germany. As with Horizon, the plan was to progress the project then sell it on. However, in 2017, Westinghouse filed for Chapter 11 bankruptcy protection and the project collapsed.

Summary

The failures and delays with these projects have not come from obstructive planning or regulation. The issues appear to have been the difficulty of finding finance partly because of the scale of investment needed and partly because of the economic risk of nuclear projects. Delays and cost overruns at the one project to start construction, Hinkley Point C, appear to result from the difficulty of building the design and the skills of the contractors.

Acoustic Fish Deterrent

The measures to protect fish from being killed by being drawn into the coolant system are often cited by those claiming the problems with building reactors in the UK are due to over-zealous regulators and planners. This is wrong. The case for Hinkley Point C put forward by EDF and approved by the Plan-

ning Inspectorate included measures to protect fish from the cooling system. The number of fish that would be killed is not precisely known. EDF estimated that the removal of the AFD would result in the death of between 1.89 million and 2.9 million fish annually. However, a report from the Welsh Government indicated that the removal of the AFD could lead to the death of at least 182 million fish each year. The Environment Agency estimated that 178 tonnes of fish would be drawn into the cooling system every year.¹³ This is not an issue just for Hinkley Point C, it will arise for coastal sites including Sizewell and Wylfa.

Planning consent given in 2013 required EDF to include three measures to protect fish: an Acoustic Fish Deterrent (AFD); low-velocity side intakes; and a Fish Recovery and Return system. In 2022, EDF appealed against the need for an AFD claiming that installing the system would mean an unacceptable safety risk to those maintaining it. Their appeal was rejected in August 2022

by the UK Secretary of State for the Environment. EDF attempted to side-step the requirement by offering to build 800 acres of saltmarsh on the River Parrett instead, a plan that also raised environmental concerns.

Whether this would have been a worthwhile project is not the issue, it clearly would have done nothing to prevent the killing of a huge number of fish in Severn Estuary. The saltmarsh plan was effectively abandoned in early 2025 when EDF claimed they now had an AFD that was workable, albeit at a cost of £700m. However, it appears the £700m covers

The failures and delays with these projects have not come from obstructive planning or regulation.

the cost of all three systems required in 2013 with the AFD accounting for only £50m of the £700m.

EDF has hinted that the process of deciding on its appeal could have delayed the completion of the station, but it has a strong incentive to suggest that the delays at Hinkley are not its fault. They have provided no evidence that there have been any actual delays due to the AFD issue. EDF clearly has a commercial interest in portraying the damage from not installing AFDs as low as possible while estimating the cost as high as possible so that the proportionality of the measures is called into question. A cost of £700m to save less than 3 million fish per year is a very different proposition to a cost of £50m to save 182 million fish every year.

One of the principles for licensing nuclear power plants is that harm should be As Low As Reasonably Practicable (ALARP) so that any damage is as low as possible within economic bounds. However, what ALARP does not tell you is whether the remaining damage is acceptable. So, a facility might include state-of-the-art protection measures that met the ALARP criterion, but the remaining risk might still be unacceptable.

“The failures and delays with these projects have not come from obstructive planning or regulation. The issues appear to have been the difficulty of finding finance partly because of the scale of investment needed and partly because of the economic risk of nuclear projects.”

Most expensive place to build reactors in the world

One of the often-repeated claims of those advocating deregulation of the nuclear sector is that the UK is the most expensive place in the world to build nuclear power plants. However, the analytical evidence to back this claim is missing. Making a valid international comparison of costs will inevitably not be precise because of the difficulties raised in putting costs on a comparable basis correcting for varying currency exchange rates and inflation in the different countries involved. However, making meaningful comparisons is made much more difficult by the dearth of reactor orders in the past two decades. To

make a fair comparison, it is necessary to focus only on designs that meet current European and US regulatory standards – older technologies lacking currently required systems will be cheaper and easier to build. It is also necessary to focus on

countries that can offer reliable, audited costs.

On these criteria, the UK has the incomplete Hinkley Point C project, which is about halfway through its construction period. The comparators in Europe are Finland with the Olkiluoto EPR completed in 2023 after 18 years of construction and France with the Flamanville EPR, in February 2026 still incomplete after more than 18 years. In the USA, the two Vogtle AP1000 reactors took 10-11 years to build compared to the four years forecast and at about three times the estimated cost. The two Summer AP1000s

Finland with the Olkiluoto EPR completed in 2023 after 18 years of construction and France with the Flamanville EPR, in February 2026 still incomplete after more than 18 years.

were abandoned after four years of construction because costs and times were out of control. Whether the record of the UK will turn out to be worse than that of the other countries seems only of academic interest given that all five projects were all clearly economic disasters.

Korea and China are often cited as countries where reactors can be built to time and cost. For China, the evidence is weak. Independently audited costs are not available. Given that the three owners of most of the plants are state-owned and are also the three reactor vendors competing to win export orders, they have a strong incentive to portray

the cost of their reactors as low. Labour costs in China are far lower than Europe and the USA and this will inevitably reduce costs. If we are to draw the conclusion that we should emulate China, we would need to take account of these lower labour costs and be confident the standards of quality control, regulation and democratic accountability in China are comparable to those required in Europe and the USA. Many of the reactors completed in China in the past two decades use an old design dating from the 1970s that would not be considered elsewhere. The six reactors built using Western technology (four AP1000s and two EPRs) have the longest construction times of almost all the Chinese reactors – 10 years compared to the four years planned and not much quicker than the Vogtle project in the USA.

Claims that the UK is one of the most expensive places to build nuclear power plants

are wide of the mark. Comparator projects in Finland, France and the US show similar overruns of cost and delays in construction.

Korea is also often cited as a country building reactors to time and cost. As with China, there is the issue of authenticity of costs. The utility (KEPCO) is a state-owned monopoly and is also the Korean reactor vendor. It has strong reactor export ambitions so has a clear incentive to portray low costs and times. It

The reactors built using Western technology have the longest construction times of almost all Chinese reactors – 10 years compared to the 4 years planned.

has completed four reactors in Korea using its most recent design, the APR1400. The first took nine years to build with the following three taking 11 years, giving no evidence for the positive effect of learning. KEPCO has

acknowledged that the APR1400s it has built (four each in Korea and UAE) would not meet European regulatory standards. These would require a system such as a core-catcher to contain the impact of a core melt-down and a toughened reactor shell capable of withstanding impact from an aircraft. Adding these would substantially increase costs.

Korea's technology is licensed from Westinghouse who will not allow it to be built in Europe apart from in the Czech Republic so Korean technology is not an option for the UK.

UK can regain its position as global leader in nuclear technology

In its final report, the Taskforce claimed that implementing its recommendations would: “allow the nation to reclaim its position as a global leader and capitalise on the worldwide nuclear renaissance, ensuring a secure and

prosperous future.” This is a misrepresentation of the UK’s status. Along with the USA and Russia, the UK was one of the first countries to generate electricity from nuclear power plants but with a technology, Magnox, which was not pursued. It has never been a significant supplier of nuclear technology outside the UK. The record of its first reactor technology, the Magnoxes, was mediocre and that of its successor technology, the Advanced Gas-cooled Reactors, was disastrous. Only two reactors, both Magnox design, have been exported, both ordered in 1959. Other UK nuclear technologies, such as the Thermal Oxide Reprocessing Plant (THORP) and the Mixed Oxide fuel plant have an even worse record. Given the poor economic record of nuclear technology in general, customers will be looking to reduce the risk by choosing suppliers with a substantial and successful track record in the technology.

It is highly unlikely that the UK could achieve a position as a major nuclear technology supplier in the foreseeable future. The UK will need to build its nuclear skills but in decommissioning and waste disposal. It will

inevitably be one of the pioneers in these areas but only because a much high proportion of its nuclear facilities than almost all other nuclear countries have already been shut down.

There is also the issue of whether being a technology leader in supplying new reactors is worth aiming for. If, like previous claimed global nuclear revivals, the new one peters

out with few orders placed, being a world leader will be no more valuable than leading the world with hovercraft technology.

Predictable series ordering of standardised designs will reduce costs

This has been a claim made by the nuclear industry for more than 50 years. It is a strategy that has only been tested in France, which started construction of 58 reactors in the 20 years between 1971-1991. These were based on a design that evolved slowly through ‘tranches’ of 4-16 reactors with the design within each tranche fixed. It is widely assumed that the predictability, standardisation and scale of this flow of orders led to falling real costs and construction times. The evidence is to the contrary.

“The UK will need to build its nuclear skills but in decommissioning and waste disposal.

It will inevitably be one of the pioneers in these areas but only because a much high proportion of its nuclear facilities than almost all other nuclear countries have already been shut down.”

The first eight reactors took on average 70 months to build

while the last eight averaged 135 months with the slowest of the first eight taking two years less than the fastest of the last eight. There have been several analyses of French construction costs using official French data and all show the real cost of French reactors increased significantly over the period of the programme. The US energy economist Charles Komanoff found the real cost had in-

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creased by 60%; the Austrian scholar Arnulf Grübler characterised the French programme as “a case of negative learning by doing;” the US nuclear research scholar, Mark Cooper, found that “French reactors have escalated in price at almost the same rate as those in the U.S.”

Responses to the Regulatory Review

While the press response to the Regulatory Taskforce was generally positive, there has been an increasing flow of criticism from expert bodies. Ruth Wilkinson, Institution of Occupational Safety and Health, contested the claim that relaxing health and safety rules was an effective way to speed up UK infrastructure projects. She said: “Stripping back protections in the name of speed is a false economy that risks lives, reputations and resilience. The UK’s health and safety framework is the backbone of safe and sustainable growth.”

The Wildlife Trusts said: “The Nuclear Regulatory Review recommendations 11, 12 and 1932 will harm nature and biodiversity. They are based on flawed evidence relating to environmental regulations and how they have been applied.”

Conclusions

If policy is to be well-founded, it should be evidence-based, not based on shallow unsupported assertions that seem designed to generate headlines. The narrative that the problems in the UK are down to obstructive regulation and planning and regulatory processes; that other countries can build reactors to time and cost; and that the UK could become a major player in an expanding world nuclear market is a fantasy. If it leads to measures to deregulate planning and regulation, the consequences could be severe.

Two days after the publication of the Taskforce’s final report, the Prime Minister stated: “I warmly welcome it and endorse its approach and accept the principle of all the recommendations it has set out. We have committed to complete implementation within two years, subject to legislative timelines on elements requiring primary legislation.” Such a precipitous response does not suggest careful consideration of the implications of the radical reforms proposed by the Taskforce.

The danger is that if government effort goes into solving an issue that is not the cause of the problems, a large amount of time and public money will be wasted failing to solve problems which may be insoluble. This is time and money we cannot afford given the need to take timely and effective measures to mitigate the climate emergency.

The integrity of a regulatory system about which, less than two years ago, the government was highly complimentary about could be jeopardised. The government stated in its January 2024 ‘Roadmap’: “The UK is also a world leader in nuclear safety and security – thanks to our commitment to rigorous regulation and the creation of the internationally recognised Office for Nuclear Regulation (ONR).”

Following deregulation in the nuclear sector will only divert attention from the reality that nuclear power plants are not close to being economic; that their cost continues to increase in real terms as it has done over the entire history of nuclear power unlike competing options which are generally falling in cost; and that the foreseen worldwide nuclear revival may well, like its predecessors, not materialise. So, pursuing global leadership in a technology that has been in decline for at least 40 years would be a folly.

Long Duration Energy Storage: the key to a 100% renewable energy

PETE ROCHE | Energy Consultant and Policy Adviser

THE UK Government's Clean Power 2030 Action Plan sets out to meet 95% of electricity requirements with renewables and nuclear power by 2030. Plans include 43-50GW of offshore wind, (up from 14.7GW currently) 27-29GW of onshore wind (up from 15.7GW currently), and 45-47GW of solar power (up from 21.5GW). In 2024 renewable sources provided 50% of Great Britain's electricity. But as we become increasingly reliant on variable renewable sources, we also need to develop flexibility to accommodate and store these variable outputs. We need the ability to shift demand to times of plentiful supply and to shift

supply to times of high demand.

The 2030 Action Plan sets out to complement renewable sources with 23-27 GW of battery capacity, and 4-6GW of long-duration energy storage (LDES). Iberdrola, owner of Scottish

Power, points out that LDES is “the key enabler for a 100% renewable electricity grid.” Energy storage systems can work in concert with other flexibility technologies to balance the grid, maximise use of low-cost renewable electricity, and provide resilience during periods of low generation. Looking beyond 2030 to a fully decarbonised energy system – not just electricity, but including heat and transport – these technologies offer us the opportunity to achieve our decarbonisation aims for 2050.

Lithium-Ion Batteries

Lithium-ion batteries currently supply around 90% of global energy storage capacity, mainly in short-duration, two-to-four-hour applications. Longer duration energy storage – eight-hours or more – is in relatively low demand because renewables dominate in only a handful of locations. But it will be increasingly

Energy storage systems can work in concert with other flexibility technologies to balance the grid, maximise use of low-cost renewable electricity, and provide resilience during periods of low generation.

required for grids as renewable generation increases. It used to be thought that scaling lithium-ion batteries up to a storage duration of more than eight hours would not be cost effective, but fierce competition between lithium-ion suppliers is driving down costs, so longer duration storage is now economically feasible. The New South Wales government, for example, has awarded contracts to six new big lithium-ion battery projects which can deliver much longer duration storage than most experts had imagined possible – all longer than eight hours. Low-cost solar generated in the middle of the day can now be stored rather than curtailed and fed into the grid when demand peaks in the evening.

But lithium-ion batteries aren't the only way to store energy, and they are being challenged by a group of novel technologies aimed at storing energy for very long periods.

BloombergNEF's latest research suggests that other LDES technologies are poised to rival them for certain applications, with some already offering cheaper storage over eight hours. Most of these technologies are still at an early stage and costly, but some already achieve lower costs than lithium-ion for longer durations. Thermal energy storage and compressed air storage, for example, are the least expensive LDES technologies.

The Cap and Floor Scheme

In January 2024, the Department for Energy Security and Net-Zero (DESNZ) launched a consultation on a new scheme for unlocking investment in LDES technologies to help with

energy security and keep power system operating costs down as more variable renewable generation comes online. Research conducted by the energy research and consultancy firm LCP Delta for the government modelled potential electricity system operating cost savings if up to 20GW of LDES capacity is deployed this decade. It revealed potential savings of £24bn, equivalent to more than 3% of total costs by reducing both the cost of payments to renewables to turn off and the cost of gas generation.

In October 2024, the government decided to introduce a LDES cap and floor scheme that will be delivered by Ofgem. This scheme

is intended to ensure investors receive a minimum amount of revenue to enable investment in LDES assets. Alongside this, the cap on revenue provides returns to consumers for their support, where LDES assets

Lithium-ion batteries are being challenged by a group of novel technologies aimed at storing energy for very long periods.

operate above the cap.

The cap and floor scheme builds on the approach already used to successfully deliver more electricity interconnection. In March 2025, following a consultation, Ofgem and DESNZ published a joint Technical Decision Document detailing the regime specifics. This confirms key final details of the scheme: it sets out how the scheme will operate, when the first application window will open, how much initial capacity will be sought, and which projects will be eligible to apply, amongst other details.

On 8 April 2025, Ofgem opened the first application window, and published a Guidance for Applicants. Then, on 23rd September



Fierce competition between lithium-ion suppliers is driving down costs, so longer duration storage is now economically feasible.

2025, Ofgem announced it had completed the eligibility assessment for the Cap and Floor scheme. Projects that met the eligibility criteria then proceeded to the Project Assessment stage. 77 projects entered the final assessment stage, 48 were lithium-ion batteries; five were pumped hydro storage; 16 were vanadium-flow/ zinc batteries; five were vanadium-flow batteries; one was compressed air storage and two were liquid air and battery hybrids. These projects are mostly expected to be available in 2030 with a few available by 2033.

Most of the 77 projects are lithium-ion batteries, so some concerns have been expressed that these will be direct competitors to short duration, unsubsidised lithium-ion batteries.

Vanadium Flow Batteries

21 of the 77 projects use vanadium flow batteries. These can store power for up to 12 hours compared with about four to eight hours for lithium-ion batteries. They also have the ability to charge and discharge continuously without degrading.

Vanadium flow batteries are non-flammable and can operate effectively without the need for additional fire suppression systems. They do not contain conflict minerals (such as cobalt) and are almost completely recyclable at end of life. The key working element inside a vanadium flow battery – vanadium – is sustainably sourced and more abundant than lithium or copper, with deposits in regions across the world.

Vanadium supply is dominated by China, Russia, South Africa, and Brazil, with about

70% produced as a co-product of steel slag. Supply is increasingly supported by recycling of industrial biproducts.

The taxpayer-owned UK Infrastructure Bank has invested £25 million

in a company called Invinity Energy Systems, which manufactures vanadium flow batteries in Bathgate and Motherwell in Scotland. The Company has also attracted several private investors.

Of the 21 projects, 16 were a mixture of vanadium-flow and zinc batteries and five were vanadium flow batteries alone. Frontier Power, based in Warwickshire has announced a landmark partnership with Invinity aimed at deploying vanadium flow batteries at an unprecedented scale as part of Ofgem's LDES procurement process. The collaboration aims to position the UK as a global leader in advanced energy storage technologies. The 16 vanadium and zinc projects accepted by Ofgem were all submitted by Frontier.

Zinc Batteries

Frontier Power Ltd is also collaborating with Eos Energy Storage which produces aqueous zinc batteries in the US. Eos Energy says their batteries offer a significant reduction in the levelized cost of storage – as much as a 25% reduction when compared to lithium-ion batteries. Aqueous zinc batteries overcome the limitations of conventional lithium-ion technology. They are non-flammable, non-corrosive, and fully recyclable at the end of their useful life. They provide utility, industrial, and commercial customers with a proven, reliable energy storage alternative for three

Vanadium batteries can store power for up to 12 hours compared with about four to eight hours for lithium-ion batteries.

to 12-hour applications. The Frontier-Eos partnership opens the door to developing local manufacturing in the UK. Should significant LDES project volumes materialize using Eos techno-

logy, it could incentivize the establishment of manufacturing operations in the UK, supporting domestic supply chains and job creation.

Pumped Hydro Energy Storage

Great Britain already has 2.8GW of LDES across four Pumped Hydro Energy Storage (PHES) facilities in Scotland and Wales. These operate like natural batteries and are already crucial to the electricity system. Each facility uses two water reservoirs at different elevations and power is generated when water moves down from one to the other passing through a turbine. When demand for electricity is low, water is pumped back up to the upper reservoir where it is stored for future use.

Coire Glas, located at Loch Lochy in the Great Glen, received planning consent back in 2020. At 1.3GW with up to 30GWh of storage capacity, it could power three million homes for up to 24 hours. SSE has completed a 1.2km exploratory tunnel, marking a significant milestone for the project.

The Earba project, being promoted by Gilkes Energy, was granted planning consent in March 2025. At 1.8GW and up to 40GWh of capacity would be even larger. The proposal is to use Loch Leamhain as the upper reservoir and Loch Earba as the lower reservoir – both in the Highlands. A tunnel approxim-

EXISTING PHES	LOCATION	MW	GWh	COMPANY
Cruachan	Argyll	444	7.6	Drax
Dinorwig	Gwynedd	1728	9.1	First Hydro (75% owned by Engie)
Ffestiniog	Gwynedd	300	7.6	First Hydro
Foyers	Highland	300	6.4	SSE

PHES IN OFGEM ASSESSMENT	LOCATION	MW	GWh	COMPANY
Coire Glas	Highland	1296	30	SSE
Earba	Highland	1800	40	Gilkes
Glenmuckloch	Dumfries & Galloway	200	1.9	Foresight Group
Loch Kemp	Highland	660	9	Stratera
Loch na Cathrach	Highland	500	4	Statkraft

Five Pumped Hydro Energy Storage projects, all in Scotland, have entered Ofgem's final assessment stage: Coire Glas, Earba, Glenmuckloch, Loch Kemp, Loch na Cathrach. Between them, they have a capacity of 4.6GW. Five Pumped Hydro Energy Storage projects, all in Scotland, have entered Ofgem's final assessment stage: Coire Glas, Earba, Glenmuckloch, Loch Kemp, Loch na Cathrach. Between them, they have a capacity of 4.6GW.

ately 3km long will connect the two water bodies.

The Glenmuckloch proposal would use an old coal mine near the village of Kirkconnell in Dumfries and Galloway. At 200MW and 1.6GWh of capacity the power station would be capable of powering about 210,000 homes for eight hours with one full discharge of the upper reservoir and could start dispatching electricity by 2029, the earliest of any of the pumped storage projects being planned. Unlike some pumped storage power stations, Glenmuckloch will be a closed-loop system. It was granted planning consent in November 2016. This was varied again in 2022 to increase the operational life of the scheme.

The Loch Kemp pumped storage scheme would have a capacity of 660MW and 9GWh of energy. The project will use two existing bodies of water, Loch Kemp and Loch Ness. It would supply over one million homes with instantaneous clean electricity for up to 15 hours. A planning application was submitted in November 2023. The project is being promoted by Statera – a UK-based energy company that develops, owns and operates flexible generation, battery storage, pumped storage hydro and green hydrogen projects.

Loch na Cathrach Pumped Storage is a 500MW hydro scheme, first conceived in 2015 and granted consent by Scottish Government ministers in June 2021. It would be

located on a site around 14km south-west of Inverness and will harness the waters of Loch Ness. This facility is expected to have a storage capacity of approximately 2.8GWh– in other words it could generate at full capacity for over six hours. The project is owned by the Norwegian State-owned company Statkraft.

Liquid Air Energy Storage

Highview Power has two 3.2GWh power plants, planned for development in the UK by 2030, which entered Ofgem's final assessment stage and would be based at Hunterston in Ayrshire and Killingholme in Lincolnshire.

Highview's Liquid Air Energy Storage technology captures excess renewable energy when demand is

low, and stores it as liquid air for hours, days or even weeks.

It works by compressing air into a liquid and then cooling it to temperatures of almost minus 200°C. The air is stored in insulated tanks at low pressure. When power is

needed it will be drawn from the tanks and heated up so it expands, resulting in a high-pressure gas that powers a turbine.

On 21st November 2025 Greater Manchester Mayor, Andy Burnham, officially broke ground for Highview's prototype liquid air energy storage plant near Carrington which will deliver 300MWh of storage and an output of 50MW for six hours, enough to serve 480,000 homes.

£300m of funding is being provided by the UK Infrastructure Bank, Centrica, and a syn-

dicate of investors including mining multinational Rio Tinto, financial giant Goldman Sachs, Danish investor Kirkbi, and US-based Mosaic Capital Partners. Centrica has put £70m into the project.

Compressed Air Energy Storage

There is one Compressed Air Energy Storage project on the list of projects deemed eligible to enter Ofgem's final assessment stage. Located in Teesside, it is expected to have a discharge capacity of 50MW.

Compressed Air Energy Storage is considered to be a mature form of storage. When there is surplus electricity on the grid, the Storelectric compressed air energy storage system can use it to compress air to around

70 bar pressure, also storing the heat.

Then, when electricity is required, air and heat are released through turbines. Compressed Air Energy Storage is well known, having been built in Huntorf, Germany in 1978 and McIntosh, Alabama, US in 1991. Both

A compressed air energy storage system can use surplus electricity to compress air. When electricity is required, air and heat are released through turbines.

plants continue to operate successfully and safely, providing vital grid balancing services. Both store air in subterranean salt caverns. However, they have relatively low efficiency rates (42-54%), because they use gas to re-heat decompressing air. The Storelectric system can eliminate the need for gas re-heating, thus improving efficiency.

Storelectric Teesside Ltd is in the process of acquiring around 550 acres of industrial land on Teesside which includes underground caverns.



CATL – the largest battery producer in the world – is increasing production of sodium batteries. The company says that up to half the market could switch to sodium.

Sodium-Ion Batteries

There are many energy storage alternatives to using expensive lithium-ion batteries which either didn't apply or didn't make it onto Ofgem's list of 'projects eligible' to receive support under the 'cap and floor' scheme. One such alternative, which is gaining a lot of attention, is the sodium-ion battery. The costs of sodium-ion batteries are fast declining. It is still uncertain whether they will become a disruptive alternative to lithium-ion technology, but they could offer significant cost-savings due to the abundance and accessibility of sodium, which is considerably cheaper and more abundant than lithium. Although sodium-ion batteries have yet to achieve widespread market adoption, they are already approaching cost parity with lithium-ion batteries. Sodium-ion batteries could

be manufactured on existing lithium-ion battery production lines with only minor modifications.

Unlike lithium-ion batteries, sodium-ion batteries are not susceptible to bursting into flames when dropped or charged in the wrong way. Sodium-ion batteries could be a game-changer – enabling our grids to run on 100% renewables.

The Chinese company, CATL, is the largest battery producer in the world. It has been making sodium-ion batteries for some time, but it has now announced plans to increase production, with integration into production of electric vehicles by July. CATL says that up to half the market could switch to sodium.

In Europe, the European Economic and Social Committee will place sodium-ion batteries at the centre of its work on the EU's indus-

trial strategy. A list of manufacturers developing this technology in Europe includes Faradion (UK), which describes itself a market leader in non-aqueous sodium-ion batteries. It says sodium-ion batteries are recognised as an emergent technology and a key part of the solution for cheaper, cleaner energy. They are cheaper and safer than lithium-ion, with a higher energy density and a wider operating temperature range than other batteries.

In Austria, a company called Salzstrom has unveiled a sodium-ion battery system for use in commercial applications, having previously launched a residential photovoltaic storage system based on its sodium-ion technology. The market response to that system significantly exceeded Salzstrom's expectations. Company co-founder, Jürgen Ellensohn, says: "Many companies are specifically looking for alternatives to lithium – whether for sustainability reasons or due to safety considerations."

Iron Air Batteries

Yet another new type of battery, called an iron-air battery, is based on the oxidation (rusting) of iron. The battery is designed, by Form Energy, to cost-effectively store and discharge energy over multiple days. The first-ever project is being built with electricity supplier Great River Energy in Cambridge, Minnesota.

Great River Energy, a non-profit cooperative, will evaluate the iron-air battery system's operation over 'several years'. New Scientist

explains how it works: "when charging, a current electrochemically converts iron oxide – rust to you and me – into iron and releases oxygen as a gas. When discharging, the battery sucks oxygen back from the air and

turns the iron back to rust, generating a flow of electricity." Each of Form Energy's batteries is about the size of a washing machine – not suitable for an EV, but fine for grid-scale storage. The company has started building its first factory

in West Virginia. Form Energy's batteries are capable of storing electricity for 100 hours.

One of the projects planning to use Form Energy's batteries is in Ireland's County Donegal. FuturEnergy Ireland, a joint venture between Coillte and ESB, has been granted planning permission to build Europe's first iron-air battery facility. Known as the Ballynahone Energy Storage project, it will look modest – a collection of weatherproof containers on a three-hectare site beside an electrical substation – but what it represents could be transformative.

Gravity Storage

Gravitational energy storage is another technology being developed for long-duration energy storage. Gravity energy storage systems have inherent advantages in that they typically have a long operating life with a minimal maintenance burden. They are also relatively simple and do not require hazardous or scarce materials.

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Sadly, Edinburgh-based Gravitricity went into liquidation in 2025. Gravitricity developed a below-ground gravity energy storage system that worked by raising weights in a deep shaft and releasing them when energy is required. In 2021, Gravitricity successfully built and operated a grid-connected demonstrator at the Port of Leith in Edinburgh, validating key aspects of the technology and providing a tangible proof-of-concept for the underlying engineering approach. Little information, beyond the company's poor financials, is available as to what went wrong.

Meanwhile, on the other side of the Atlantic, Energy Vault's groundbreaking EVx™ is the world's first commercial-scale Gravity Energy Storage System (GESS), providing industry leading round-trip efficiency and a 35-year operating life. It has two gravity storage projects in China.

Flywheels

Flywheel energy storage works by spinning a rotor (flywheel) and maintaining the energy in the system as rotational energy. When energy is extracted from the system, the flywheel's rotational speed is reduced; adding energy to the system correspondingly results in an increase in the speed of the flywheel. Because energy is stored kinetically flywheels avoids many of the limitations of chemical batteries. They can charge and discharge ten times faster and only use widely available materials.

A company headquartered in Utah called Torus produces flywheel-based energy storage

systems for both residential and commercial applications. The company claims its flywheel-based technology is differentiated from chemical batteries by being 95% recyclable, unaffected by temperature fluctuations and has a 25-year service life. In September 2025 Torus secured a \$200 million investment to accelerate the deployment of its modular hybrid power plant solutions, which combines the strengths of mechanical flywheels with advanced battery storage.

Another US-based Flywheel developer, Qnetic, has just raised \$5 million to launch domestic manufacturing in California and deploy the first units of its flywheel energy storage system.

In the UK a company called Levistor is working with National Highways on a trial of its flywheel-based energy storage system (FESS) to provide a short-term power boost for fast EV chargers when the grid is unable to meet the high demand. It allows an EV driver to add 100 miles of range with just five minutes of charging.

Heat Batteries

Heat storage is rising up the agenda. Heat provides more than half the total energy demanded by industry, but according to the Institution of Mechanical Engineers (IMechE) electric batteries and hydrogen have hogged

the limelight to the neglect of simple systems storing heat.

There are various types of heat-based batteries available such as those made of rocks, bricks or sand and heated with an electric coil. They can deliver high temper-

Heat provides more than half the total energy demanded by industry, but electric batteries and hydrogen have hogged the limelight to the neglect of simple systems storing heat.

atures – anything from 100 to 1,500 degrees – to make food, beverages, paper, chemicals and a host of other materials which account for about a quarter of current fossil fuel consumption globally. Using electricity directly can be expensive, but by using heat batteries in conjunction with heat pumps, and using off-peak electricity, it can be cheap enough to provide high temperature heat for industry.

Finland inaugurated the world's largest sand battery in 2025. The 1MW/100MWh thermal storage system developed by Polar Night Energy is an industrial-scale unit in Pornainen which began operating in 2025 where the district heating company, Loviisan Lämpö, uses the sand battery as the main production facility in its district heating network.

Another Finnish company, TheStorage, says that its thermal storage technology could reduce industrial energy costs by up to 70% and cut carbon emissions by as much as 90%. The system converts renewable electricity into heat, stores it in

sand, and delivers it on-demand for industrial heating. In January 2026, TheStorage installed its first industrial-scale pilot at a brewery, putting the technology to the test in a real-world setting producing steam for the brewery's production line.

In East Lothian, a company called Sunamp has received £9.25m in government funding to trial an advanced system in 100 homes across the UK. Its technology relies on storing heat and cold in a phase-change material sim-

ilar to the gel used in pocket hand-warmers. Its heat batteries are four times more efficient at storing heat than tanks of water, allowing it to use a much smaller tank – smaller than a washing machine. These can be used, for instance, in conjunction with heat pumps. The heat pumps can be run overnight on off-peak electricity to charge up the heat battery. The battery is then discharged to heat water for the central heating systems during the day.

Hydrogen

Hydrogen is a much talked about way of storing renewable energy. The technology for producing it, by electrolysing water with renewable energy and then using the hydrogen that is released to power gas turbines, is straightforward. The less straightforward as-

pect is storing hydrogen for any length of time because it escapes from even thick metal tanks quite easily.

But it can be stored in large underground facilities similar to storage facilities used for natural gas. For instance, the 'Rough' gas storage facility off the Yorkshire coast could

be used for hydrogen storage. This facility alone would store around 10TWh of hydrogen energy, enough, on its own to power all of (at current levels) UK electricity supply four to five days even if there was not a single kWh of anything else available.

A disadvantage of hydrogen burned in conventional gas turbines is that NOx emissions are much higher compared to methane – unless that is, the hydrogen is used in fuel cells (where there are no NOx emissions). The cost

The 'Rough' gas storage facility could store around 10TWh of hydrogen energy – enough to power all of the UK's electricity supply for four to five days.

of fuel cells is coming down quickly, although they are still a lot more expensive than gas turbines. On the other hand, RWE in Germany is planning an 800MW gas turbine designed specifically to burn 100% hydrogen with much reduced NOx emissions.

One way of avoiding hydrogen leaking out of storage is by converting it to methane or ammonia. Ammonia can be produced by mixing hydrogen generated through using renewable energy to hydrolyse water and mixing with nitrogen at the same time. Lots of ammonia is currently stored for use in the fertiliser industry. Ammonia is unique as a fuel because it does not contain carbon, which means its combustion does not produce CO2 emissions.

100% Renewables

As we move on from decarbonising the electricity system in 2030 to decarbonising the whole energy system by 2050, energy storage will become even more crucial whilst also offering a cheaper more secure path to net zero. A study by renowned energy modellers at Finland's LUT University demonstrates that a 100% renewable energy system for the UK is not only technically feasible but also offers a much cheaper path towards achieving net zero in 2050 compared to the UK Government's pathway for net zero.

The UK could provide all the energy it needs from renewable sources in conjunction with short and long duration energy storage without the need for new nuclear stations or fossil gas peaker plant.

The UK could provide all the energy it needs from renewable sources in conjunction with short and long duration energy storage.

The 100% renewable energy scenario including inter-annual storage is calculated to be €129bn cheaper in total cost compared with the UK Government's present pathway to achieving net zero by 2050.

In addition, the 100% renewable energy scenarios reduce the quantity of CO2 emitted in the period up to 2050 by over a fifth compared the Government scenario (Current Policy Scenario). The main trend across all 100% renewable energy scenarios is the electrification of all sectors, leading to high system efficiency and reduced primary energy demand. The scenario is dominated by offshore wind but also includes large amounts of inter-annual energy storage to cope with fluctuations in wind power outputs within and between years. The study found that storing renewable energy as renewable electricity-based methane in conventional natural gas storage facilities is the most cost-effective means of inter-annual storage. The methane is converted from air captured CO2 and green hydrogen using renewable electricity.

Given the nuclear industry's history of delays and cost overruns, the Government should urgently examine 100% renewable energy scenarios with inter-annual energy storage as a contingency if nothing else. In the meantime, it should plan for a further LDES Cap and Floor Assessment round with a particular focus on promising technologies which failed to make it on to Ofgem's Assessment List in this round, particularly sodium-ion and iron-air batteries as well as gravity storage.

Small Modular Reactors: Game changer or more of the same?

STEVE THOMAS | Emeritus Professor, University of Greenwich

WITH current large reactor designs tarnished by their poor record of construction, attention for the future of new nuclear power plants has switched to Small Modular Reactors (SMRs). The image of these portrayed in the media and by some of their proponents is that they will roll off production lines, be delivered to the site on the back of a truck and, with minimal site assembly, be ready to generate in next to no time; they will be easy to site, a much cheaper source of power, be safer and produce less waste than large reactors; as a result, they are being built in large numbers all around the world. But what is the reality?

What are SMRs and AMRs?

In terms of size, the International Atomic Energy Agency (IAEA) defines SMRs as reactors producing 30-300MW of power and defines reactors producing up to 30MW as micro-reactors. In practice, the size of SMRs is increasing and of the seven designs that have received UK government funding, four are at or beyond the 300MW upper limit for SMRs. The vendors of the two micro-reactor designs funded by the UK have both collapsed, leaving

the X-Energy Xe-100 the only reactor design, at 80MW, that is technically an SMR.

The term Advanced Modular Reactor (AMR) is largely a UK invention and denotes reactors using designs other than the dominant large reactor technologies – Pressurised and Boiling Water Reactors (PWRs and BWRs). In other countries, the term SMR covers all reactors in the IAEA's size range. None of the proposed AMR designs are new, all having been discussed for 50-70 years but not built as commercial reactors. They can be divided into those built as prototypes or demonstration reactors – the Sodium-cooled Fast Reactor (SFR) and the High Temperature Gas-cooled Reactor (HTGR) – and those that have not been built – Molten Salt Reactors (MSRs) and Lead-cooled Fast Reactors (LFRs).

Some designs include a heat storage device so that when demand is high, this heat can be used to generate additional electricity as well as that generated by the reactors. When electricity demand is low, the heat produced by the reactor can be stored for when demand is higher, giving it a generating flexibility. For example, the Terrapower SFR design includes molten salt heat storage to boost the station's



Sizewell A, now decommissioned, was a Magnox station with two reactors of far less than 300MW. In the background is Sizewell B, a PWR with an output of 1,200MW. Scaling up didn't make nuclear economical.

output from 345MW to 500MW at peak times. This is intended to address the issue that operating reactors in 'load-following mode' is problematic technologically and economically. It is not clear whether this generating flexibility justifies the substantial additional expense of the heat storage system.

What is the case for SMRs and AMRs?

SMRs and AMRs are presented, not only by the nuclear industry, but also by the media and government, as established, proven, commercial products. The main claims for SMRs and AMRs compared to large reactors are:

They will be cheaper to build per kW of capacity and less prone to cost overruns;

They will be quicker and easier to build and less prone to delay;

They will produce less waste per kW of capacity;

Building components on factory production lines will reduce costs;

Modular construction, reducing the amount of site-work, will reduce costs and delays;

They will be safer;

They will generate more jobs.

There have been numerous critiques that demonstrate these claims are at best unproven or at worst simply false. The summary of the critiques on each point is as follows.

Construction Cost

The first commercial reactors worldwide were mostly in the SMR size range, but they proved uneconomic and the vendors continually increased their size to gain scale economies,

SMRs will produce more voluminous and chemically/physically reactive waste than Large Light Water Reactors.

culminating in the 1600MW Framatome European Pressurised Reactor (EPR). Intuitively, a 1600MW reactor vessel will cost less than ten 160MW reactor vessels. While increasing their size was never enough to make the reactors economic, it is implausible that scaling them down will make them cheaper per unit of capacity because of the lost scale economies. It appears that SMRs are struggling to be economically viable. Holtec doubled the electrical output of its design at some point in 2023. The realistic competitors to SMRs are not large reactors but other low-carbon options such as renewables and demand-side management.

Construction time

There is no clear analysis explaining why reactors are now expected to take longer to build and why they seem more prone to delay. However, it seems likely that the issue is that the designs have got more complex and difficult to build as they are required to take account of vulnerabilities exposed by events such as the Fukushima disaster. The problems thrown up by the occupation of Ukraine's Zaporizhzhia site by Russia have yet to be taken up in new reactor designs. As a result of the 9/11 terrorist attack on New York, new reactor vessels are required to be able to withstand an aircraft impact. The conflict in Ukraine spilled on to the Zaporizhzhia site causing concerns that a serious accident would result. Analysis suggests that the exterior of other parts of the

plant should be toughened. If the issue is complexity rather than size per se, reducing the size of the reactors may do no more than make construction a little easier.

Waste

For SMRs, there is a clear consensus that they will produce more waste per unit of capacity than a large reactor. For example, Nuclear Waste Services, the UK body responsible for waste disposal said: "It is anticipated that SMRs will produce more waste per GW(e) than the large (GW(e) scale) reactors on which the 2022 IGD data are based."

Alison MacFarlane, former chair of the US Nuclear Regulatory Commission (NRC) wrote: "The low-, intermediate-, and high-level waste stream characterization presented here reveals that SMRs will produce more voluminous and chemically/physically reactive waste than LWRs, which will impact options for the management and disposal of this waste." The AMRs will produce an entirely different cocktail of waste varying according to the type of reactor.

Factory production lines

In principle and in general, production lines, which have high set-up costs, can reduce costs with high-volume items with a fixed design and a full order book. But, if demand is not sufficient to fully load the production line or the design changes requiring a re-tooling, the fixed costs might not be fully recoverable.

The production lines proposed for SMRs will produce less than a handful of items per year — a long way from a car or even an aircraft production line — and the market for SMRs is uncertain, so guaranteeing a full order book is impossible.

There is also a 'chicken and egg' issue that the economics of SMRs will only be demonstrated

when the components are produced on production lines, but production lines will only be viable when the designs are demonstrated sufficiently to provide a flow of orders.

Modularity

Modularity is a rather vague term, and all reactors will be made up of components delivered to the site and assembled there, any difference between designs being down to the extent of site work. The Westinghouse AP1000 design is said to be modular but this did not prevent all eight orders suffering serious delays and cost overruns. Framatome now describes the successor design to the EPR, the 1600MW EPR2, as modular.

Safety

Some of the SMRs and AMRs rely on ‘passive’ safety, in other words, they do not require the operation of an engineered system to bring the reactor back under control in the event of an accident. A common assumption is that because it is passive, it is fail-safe, and will therefore not require back-up safety systems and so will be cheaper. None of these assumptions is true and, for example, the UK Office of Nuclear Regulation (ONR) has said for the 20MW PWR design from Last Energy: “ONR advised that it is philosophically possible to rely entirely on two passive safety systems, providing there is adequate defence in depth (multiple independent barriers to fault progression)”. Some designs rely on being built underground but the Nuward and NuScale designs that use this have struggled to win orders with Nuward being abandoned and NuScale losing its only major order prospect because of rising costs.

Job creation

A key selling point for SMRs is that they will require much less site work and that implies

fewer jobs. More of the work will be done in factories but the business model for SMRs requires that, globally, as few factories be built as possible to maximise scale economies, so if, for example, the factory is not in the UK, neither will the jobs be.

What is the experience with SMRs?

Many reactors that fall into the size range of SMRs were built in the 1960s including 24 reactors in the UK. By the mid-60s, almost all new orders were for reactors larger than 300MW. This century, only two SMR projects have been completed, one in China and one in Russia, but neither design appears to have any firm follow-up projects. Two projects are under construction, one in Russia and one in China, but neither design appears to have any further firm order prospects. There is one micro-reactor under construction in Argentina (*see Table below*).

The most advanced project using a commercially available design is for a GE Vernova BWRX-300 reactor to be built at the Darlington site in Canada. There appears to be a firm order for this reactor although by January 2026, construction had not started. The Canadian safety regulator will assess the design during the construction period, not before construction starts as would be required in most jurisdictions; this gives rise to a risk of delays and

“Many reactors in the size range of SMRs were built in the 1960s including 24 reactors in the UK.”

cost escalation if a design issue requiring additional cost emerges during construction.

There are several other projects with a named site and design, often presented in the media as being under construction, but these have yet to receive regulatory approval for the design, they do not have construction permits and a firm reactor order has not been placed. Those listed in *Table 1* are the ones that appear most advanced in terms of regulatory approvals. Numerous other projects have been publicised, invariably with ambitious completion date targets, but they are some distance from a firm order being placed. Up to this point, historically, a high proportion of nuclear projects of all sizes announced do not proceed and there is no reason to believe this will not be the case with these projects. Once a firm reactor order has been placed, the project

is more likely to go ahead because the cost of abandonment is high.

The two operating SMRs (in China and Russia) have a very poor record in terms of construction time and operating performance, but authoritative construction costs are not known. Completion of the three under construction is also behind schedule. While these projects are not for commercial designs, this provides no evidence that the ambitious claims for SMRs will be met.

Conclusions

The perception that SMRs are being built in large numbers is untrue and the claims made for them in terms of, for example, cost, safety, and waste are at best unproven and at worst false. The image of them being much smaller

COUNTRY	SITE	VENDOR	TECHNOLOGY	OUTPUT MW	STATUS	BUILD START	COMMERCIAL OPERATION	LOAD FACTOR
Russia	Lomonsov	Rosatom	PWR	2 x 32	Operating	2007	2020	32.1%
Russia	Brest	Rosatom	SFR	300	Under construction	2021	2028/29	
China	Shidao Bay	Tsinghua	HTGR HTR-PM	200	Operating	2012	2023	26.9%
China	Linglong 1	CNNC	PWR ACP100	100	Under construction	2021	2026?	
Argentina	Carem 25	CNEA	PWR Carem	25	Under construction	2015	2028?	
Canada	Darlington	GE Vernova	BWRX-300	300	Firm order	-	2030?	
USA	Kemmerer	Terrapower	SFR Sodium	345	Under construction	-	2031?	
USA	Palisades	Holtec	PWR SMR300	2 x 340	Pre-licencing	-	2030?	
USA	Clinch River	GE Vernova	BWRX-300	300	Under construction	-	2033?	
UK	Wylfa	Rolls Royce	PWR	470	Design review	2030?	2035?	
UK	Llynfi	Last Energy	PWR	4 x 20	Site licence applied for	2028?	2030?	

The idea that siting and building SMRs will be easy is not credible; a reactor of more than 300MW will need to be carefully sited and will require substantial on-site work, suggesting that the claim that these projects would be largely factory built is implausible.

than existing reactors is incorrect. The IAEA's size range is arbitrary but the clear trend for SMRs to increase in size does put a question mark against the claims made for them such as reduced cost per kW due to small size, ease of siting and mass production. Most of the designs that have realistic order prospects are at or beyond the 300MW upper limit of the IAEA range for SMRs. This is illustrated by the Holtec design which, for more than a decade was being developed as a reactor, SMR160, designed to produce 160MW of electricity. In 2023 and with no publicity, the output of the reactor was doubled to become the SMR300 and projects using this technology are foreseeing 340MW

of power. The idea that siting and building them will be easy is not credible; a reactor of more than 300MW will need to be carefully sited so it is not vulnerable to sea-level rise or to seismic issues and will require substantial on-site work including foundations, suggesting that the claim that these projects would be largely factory built is implausible. It would also mean that either the modules would be very large making them difficult to transport or would require a larger number of modules increasing the amount of site-work.

This increased size also means that the image of a rolling production line producing large numbers of reactors is inaccurate. Rolls Royce, whose design has increased to 470MW, is anticipating its production lines would produce components for only two reactors per year.

The UK, along with Canada and the USA is in the vanguard of development of SMR designs. The history of nuclear power shows that developing new reactor designs is an expensive

venture with a high probability of failure. The UK's chosen design is the largest SMR design on offer and is being developed by a company with no experience designing or building civil nuclear power plants. Submarine reactors have

The two operating SMRs (in China and Russia) have a very poor record in terms of construction time and operating performance

very different design priorities and the reactors built by Rolls Royce use US designs. There is huge scope for the UK to build much cheaper offshore wind and to carry out energy efficiency measures which would have the double dividend of reducing emissions and tackling fuel poverty. It would make much more sense for the UK to let other countries make the investments and take the risk and only if SMRs are shown to fulfil the claims made for them to then adopt them as part of the UK's generating mix.

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