The University of Manchester
Dalton Nuclear Institute

# The road to net zero: **renewables and nuclear working together**


Authors: Juan Matthews
William Bodel
Gregg Butler

Director: Zara Hodgson



Published: October 2024


**www.manchester.ac.uk/dalton**

# Contents

# List of Acronyms

| | |
|---|---|
| AMR | Advanced Modular Reactor |
| BECCS | BioEnergy with Carbon Capture and Storage |
| BEIS | (Department for) Business, Energy and Industrial Strategy |
| CCGT | Combined Cycle Gas Turbine |
| CCS | Carbon Capture and Storage |
| Cu-Cl | Copper-Chlorine (cycle) |
| DAC | Direct Air Capture |
| DESNZ | Department for Energy Security and Net Zero |
| ESO | Electricity System Operator |
| ETS | Emissions Trading Scheme |
| FT | Fischer-Tropsch (reaction) |
| HTGR | High Temperature Gas-cooled Reactor |
| LCOE | Levelised Cost Of Electricity |
| LWR | Light Water Reactor |
| PEM | Proton Exchange Membrane |
| PV | (Solar) PhotoVoltaic |
| PWR | Pressurised Water Reactor |
| RAB | Regulated Asset Base |
| RWGS | Reverse Water-Gas Shift |
| S-I | Sulfur-Iodine (cycle) |
| SOEC | Solid Oxide Electrolyser Cell |
| SMR | Small Modular Reactor |
| TRL | Technology Readiness Level |
| UNECE | United Nations Economic Commission for Europe |
| VRE | Variable Renewable Energy |

# Foreword

## Transitioning to a net zero power and energy future by 2050 is a critical national mission. It must be achieved in a way that locks in affordability for consumers, economic growth and jobs, innovation for resilience and leadership, and above all energy security.

Delivering net zero is challenging and complex, requiring a whole system approach that uses the best mix of low-carbon energy technologies that are available now, alongside those that will be deployable in the future. The UK has been highly successful in driving forward the expansion of renewable energy to displace fossil fuel burning power plants, and the ambition of accelerating to entirely clean electricity production within the next decade could be in touching distance.

Yet, wind and solar are inherently variable, after all weather forecasting is a stereotypically British hobby; this brings challenges to financing, building and operating an affordable, efficient net zero energy system. The installation of back-up natural gas burning power plants and energy storage technologies has so far been the proposed solution to the UK's changeable island weather, despite drawbacks of high-cost electricity, wasted energy and continued $CO_2$ emissions. So, at the Dalton Nuclear Institute, we have asked ourselves if the UK should look again at how nuclear electricity and *nuclear heat* could accelerate the renewable energy technology led transition to net zero, and also underpin UK leadership in addressing climate change.

Through detailed modelling of a potential 2050 UK energy system, we can illustrate that the variability challenge faced by a carbon-free economy can be addressed more efficiently than the way it is currently envisaged, at lower overall cost, with more UK jobs and without backup fossil fuels. We do this by exploring a fundamental change to how nuclear energy is typically modelled to operate in the system; changing from baseload production of electricity only, to an approach instead, which is based on flexible production of high-quality heat, hydrogen and electricity from a fleet of nuclear reactors – large, small and advanced – and associated energy storage.

The potential energy future that we put forward to spark further discussion is a maximal scenario for electrification of over 840 TWh total supply; three-quarters of which is supplied by variable renewable energy, just 10% by nuclear plants and 0% from fossil fuels. Clearly, such a maximalist approach to clean energy requires a hugely demanding build programme of new renewable and nuclear infrastructure, in terms of pace and scale, as well as siting closer to energy end users. Highly sophisticated grid design and management would also be needed to trade and balance the supply-demand requirements of electricity, heat and hydrogen. However, the benefits that could be realised, not least energy independence and savings of up to £14 billion per year on the current UK energy system scenario, merit attention and analysis. We welcome being part of this integrated renewables and flexible nuclear system debate.

Our analysis indicates future promise for a flexible, fossil fuel free energy system that integrates the synergistic advantages of renewable energy and cogenerating nuclear energy, as the technologies become deployable in the system from now to 2030, then onto 2040, and finally full implementation by 2050. Capitalising on the flexibility of nuclear energy to contribute more than just low carbon electricity is a key innovation opportunity for the UK and offers leadership in international net zero initiatives and enhanced energy security.

Underpinning a transition to net zero by integrating electricity generation, from both renewables and nuclear, along with nuclear-enabled heat and hydrogen production must be explored. The time to research, evaluate and plan for the delivery of the UK's clean energy future is now.

**Zara Hodgson**
**Director, Dalton Nuclear Institute**
**The University of Manchester**

# Executive Summary

In order for the UK to achieve net zero greenhouse gas emissions by 2050 there will need to be a significant increase in the proportion of UK energy that is delivered by electricity, and which must be predominantly low-carbon. This is reflected in recent Government policy, and is obvious from the anticipated shift to a greater role for electricity to support transport, domestic heating and industrial processes.

The bulk of the 2050 electricity supply is anticipated to be from renewable generation – predominantly wind and solar. However, these renewable sources are unavoidably variable, so additional resources are required to deliver a functioning electricity grid by managing the inherent intermittencies. It is the options to achieve this balance, ensuring a stable and secure electricity supply, that are the subject of this investigation.

Options to cope with the variability of renewables include natural gas (with and without carbon capture), shorter-term storage such as batteries, medium-term storage such as pumped hydro, longer-term storage of hydrogen for use in gas turbines, and nuclear energy. The light water reactors typically employed for nuclear power generation have limitations on the flexibility of generation that can be achieved and are also limited by the fact that lower fractions of time spent on generation (i.e. lower capacity factors) lead to rapidly increasing unit generation costs for reasons that will be discussed.

Low-carbon electricity generation and grid system scenarios have been detailed by the Department for Energy Security and Net Zero (DESNZ) for the Government, and they largely limit the role of nuclear to baseload electricity generation. Building on these analyses, this study sets out to illustrate how considerable improvements could be made, in both net zero system economics and carbon emissions, to maximise the potential of renewable electricity generation by utilising a flexible combination of nuclear electricity and nuclear heat, known as cogeneration.

This combination of nuclear electricity and nuclear heat is examined for large, gigawatt-scale reactors and Small Modular Reactors (SMRs), together with the possible inclusion of Advanced Modular Reactors (AMRs) in the UK's 2050 nuclear fleet; especially High Temperature Gas-cooled Reactors (HTGRs) with hydrogen generation. These HTGRs are currently the subject of a UK Government-backed programme for a demonstration reactor to be operational in the "early 2030s", but the possible fleet build has yet to be accommodated in official scenarios.

The low-carbon electricity generation and grid system scenarios examined to date have included the use of unabated gas generation, operating for only a small percentage of the time. This "low capacity factor operation" means that all the capital and operating costs must be recovered by selling a small amount of electricity, and means that the unit production cost of the electricity will be very high. Seemingly cheap sources of electricity become expensive when their capacity factor is reduced. This fact alone was one of the factors that pointed to the importance of the current study.

### *Recommendation One*

***All energy infrastructure becomes less economically effective per unit of output as the capacity factor reduces. Government decision-making on the future energy mix should consider the capacity factors of new and existing infrastructure, and where these are low, seek alternatives which are potentially more cost effective.***

As electricity generation and supply is progressively decarbonised, the proportion of renewables in the UK system scenarios increases. Some renewables are predictable and electricity supply can be controlled – examples include bioenergy (i.e. burning biomass or its derivatives), geothermal energy and hydroelectric power. Other renewables, such as wind and solar photovoltaic, are known as "Variable Renewable Energy" (VRE) sources because of their reliance on variable weather conditions. VRE sources can experience periods from a few days to over a month with little to no generation, leading to problems of balancing generation with demand. While short-term balancing can be achieved with pumped storage and batteries, using these for longer-term grid support becomes very expensive, requiring alternative support generation be in place instead. In addition to this, regular periods are expected where generation will exceed demand. Currently, this excess electricity generation is "curtailed", with generators being paid not to deliver to the grid via "constraint payments" – put in other words: it is wasted. This will increase with increasing VRE on the grid unless a solution can be found.

The work in this report was developed around the same time as a study by the Royal Society on large scale electrical storage to integrate large fractions of VRE into the electricity network. This work and the Royal Society study came to many of the same conclusions with the main difference being our drive to recognise the opportunity to use current and advanced nuclear technologies for cogeneration rather than straightforward electricity generation. Leaning into this opportunity would enable diversion of some of the nuclear capacity as a lower cost dispatchable source of power; an important addition to the methods available to the grid for bridging the gap when renewables are not available. The use of large-scale electrical storage is also favoured in the most recent report of the Energy Systems Catapult.

Our work recognises the need for low-carbon hydrogen from nuclear as longer-term storage; shorter-term battery and pumped hydro storage, which are valuable to maximise renewables exploitation; and BioEnergy with Carbon Capture and Storage (BECCS) to provide a negative emissions component.

### *Recommendation Two*

***Since variable renewable energy generation can experience long periods with little to no output and storage options are limited in scale, Government should ensure that the delivery of low-carbon, cost-effective, dispatchable electricity is prioritised to best support an effective overall system.***

### *Recommendation Three*

***As the proportion of variable renewable energy on a network increases, so will the amount of curtailment unless close attention is paid to the whole system. Government should ensure that the inefficiency of curtailment is recognised and that it is minimised as far as possible, for instance by ensuring that large-scale solar power has associated electricity storage.***

One method of improving flexibility of nuclear power is to combine it with thermal storage. The higher temperatures produced by some AMRs make them particularly suited to production of hydrogen and other synthetic fuels, as well as heating for a large range of industrial applications. This potential is further exploited in several AMR conceptual designs that choose to incorporate molten salt thermal storage, combined with an electrical generation capacity several times that from the reactor system, when directly connected to the generation system. With such a setup, at times of low electricity demand, energy is directed to the heat store; during high demand, this stored heat can be converted into electricity, using the larger generating capacity.

Continuous operation of the reactor plant would be enabled, while allowing load following and, when necessary, very low electrical power output. This arrangement of a reactor plus thermal store opens the prospect of broader commercial uptake by end users, through considerable availability of economic, flexible, useful energy output, and should be investigated.

### *Recommendation Four*

***Using reactors with thermal storage can potentially offer a cost-effective contribution to solving the problem of nuclear inflexibility. Government should prioritise research to enable an in-depth investigation of the opportunity.***

Nuclear energy generation must demonstrate that its economics are adequate for the role(s) which are proposed in the overall energy system, and its perception as being inflexible must be addressed.

Improving the economics of nuclear energy must involve reducing build times and costs by utilising fleet build and factory fabrication, and operating reactors at high capacity factor.

### *Recommendation Five*

***Government, working through Great British Nuclear, should strive to improve the economics of nuclear energy by encouraging fleet build of nuclear plants, with minimal delays, and which are then operated at a high capacity factor.***

These initial recommendations have a common focus on establishing a holistic view of any viable "Net Zero by 2050" scenario. The various elements must function together to produce a day-to-day and hour-to-hour regime that maintains a continuous electricity supply, optimum economics, and minimum carbon production. This has major implications on how the programme for 2050 is progressed – combining a whole system viewpoint with an essential ability to identify, and enact, changes and programmes across the whole system.

***Recommendation Six***

***Government's future energy strategies should include full appreciation of effects at the whole system level, comprising generation, transmission, and storage, which must all be developed in parallel.***

The potential of nuclear energy technologies to alleviate the problems of VRE intermittency and curtailment is explored in this paper. The main body of this work compares the DESNZ reference case (the "High Electrification" scenario) with a new alternative "Flexible Nuclear" cogeneration scenario to replace the unabated natural gas peaking support. This comprises an additional 60 GW of thermal power with thermal storage, enabling up to 90 GWe of electrical power delivery.

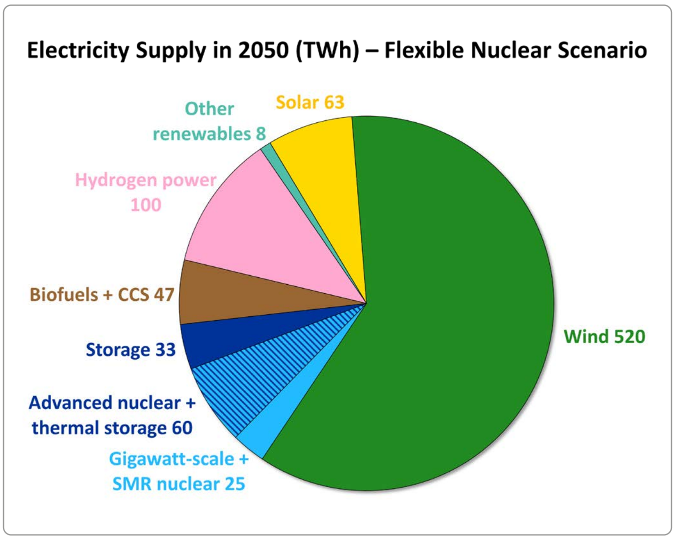
The 24 GWe of gigawatt-scale and SMR nuclear from the original DESNZ scenario and the additional AMR capacity would be mainly directed at cogeneration activities, with peaking support for the grid when needed. In addition to the increased role for nuclear in grid support, BECCS and hydrogen fuel turbines are used at a higher capacity factor. The hydrogen would be nuclear cogeneration-derived hydrogen. Results from the Flexible Nuclear scenario are tentative estimations at this stage but suggest some very clear advantages over the original DESNZ High Electrification scenario. These include, for 2050:

- Annual savings of up to £14 billion (a ~16% reduction) in delivering ~850 TWh of electricity to the grid, depending on how many reactors can be built by 2050.
- A reduction of the life cycle averaged $CO_2$ equivalent emissions from ~75 Mt to ~15.5 Mt.
- An increase in potential for nuclear cogeneration for hydrogen production from ~15 Mt/yr to ~300 Mt/yr (or ~60 TWh to ~1000 TWh in heat terms).

The key to making these large savings available is to remove the inflexibility of nuclear generation, which has led to it to be used solely for baseload electricity generation. This is addressed by widespread use of cogeneration, which enables continuous operation of reactors to provide mixed energy outputs, as heat and electricity for hydrogen production, as well as electrical support for the grid when required. The Flexible Nuclear scenario developed proposes large-scale application of VRE and nuclear, where nuclear is operating largely in cogeneration mode; leading to increased overall efficiency in energy use, and with minimal carbon detriment.

All of this is, of course, subject to the demonstration of the economics of newer nuclear technologies – notably fleet operation of SMRs and HTGRs. The scenario is at the upper limit of what might be achieved, and yet it may be possible to only partially implement it and still realise benefits by 2050. The level of the savings that can be achieved will depend on the extent to which this scenario can be implemented. Equally, existing and currently proposed projects should examine their potential applicability for cogeneration, and naturally the scenario also relies on the development of the associated cogeneration activities with heat storage and high temperature heat transport.

Consistent with the DESNZ High Electrification scenario, renewable energy provides the bulk of the electricity in the Flexible Nuclear scenario – the 2050 electricity supply by source is shown below. The two key differences are that the nuclear contribution is delivered as part of cogeneration activity, and all reliance on natural gas is eliminated.



### *Recommendation Seven*

***Government assessments of the impact of new nuclear capacity should recognise and incorporate cogeneration applications (including hydrogen production). These applications ensure high capacity factors can be achieved to keep costs low and provide grid support when renewable output is low. Where appropriate, the same reasoning should be applied by the operators of existing nuclear plants.***

An energy system incorporating significant capacity to produce hydrogen from electricity should allow for excess VRE electricity generation at times of low demand to be directed to hydrogen production and reduce the amount that is curtailed. Ideally, excess VRE electricity should be combined with heat from the nuclear sources to maximise hydrogen production efficiency.

### *Recommendation Eight*

***Government and industry should aim to reduce the need for curtailment of renewable electricity by using cogenerated nuclear heat to power high-temperature electrolysis hydrogen production, in addition to short-term storage.***

A potential problem is that the adoption of large-scale baseload power generation in a VRE-heavy system will inevitably increase the amount of curtailment of VRE and so increase costs. So, in addition to reducing costs of nuclear, this study examines how nuclear can provide energy beyond purely baseload electricity generation.

The suggested Flexible Nuclear solution to the challenge of net zero involves extensive and flexible use of nuclear energy, with hydrogen production and heat storage to accommodate the variations in VRE output and grid demand. It is recognised that success in producing hydrogen efficiently from the nuclear heat is needed, as is the presence of a robust grid, able to accommodate increased requirements and variability. Yet this suggested solution would ensure high capacity factors to further improve the economics for nuclear that embraces a fleet approach to modular new build and a beyond baseload ethos. It also requires success in producing hydrogen efficiently from the nuclear heat, and the presence of a robust grid, able to accommodate increased requirements and variability.

### *Recommendation Nine*

***Nuclear energy should not be restricted to delivering only baseload electricity generation. The possibility of locating new nuclear build on existing or purpose-built industrial parks that would maximise the opportunity for cogeneration must be explored.***

Synergy is an important reality, which must be faced if an effective low-carbon energy future is to be achieved. As electricity becomes more and more the responsibility of VRE generators, lots of additional baseload nuclear generation may not just be unhelpful, but actively detrimental to the entire system, as it presents a dilemma between idling thermal generators or large-scale VRE curtailment. Intelligent planning is therefore essential, and energy decisions should not be made in isolation, but with an appreciation of how each technology fits in the whole system.

### *Recommendation Ten*

***Government planning for future nuclear deployment should envisage an integrated system where nuclear and variable renewables work in harmony through cogeneration and energy storage, while planning around energy (not just electricity) infrastructure delivery should be fully co-ordinated to best ensure the UK has a functional whole system.***

# 1 Introduction

The UK Government is committed to reaching net zero greenhouse gas emissions by 2050 [1]. To achieve this it is generally accepted, and reflected in Government policy, that by 2050:

1. A considerable increase in the energy delivered by electricity is needed.
2. The electricity supply must be predominantly low-carbon.

The UK is therefore seeking to implement an electricity system with zero net greenhouse gas emissions as part of its Net Zero Strategy. This must ensure a low-carbon electricity supply to consumers, relying on a robust grid which is resilient to variations in electricity demand and generation (especially weather for renewables). This paper explores in some detail the way in which low carbon technologies – specifically renewable energy and nuclear power – can work effectively, in combination, to contribute towards net zero.

The work in this report was carried out before the change of Government in July 2024 and does not include any new developments following the recent King's Speech where it was announced that the UK plans to have fully clean power by 2030 [2]. The main inputs to this report are from annual energy projections published by the Department for Energy Security and Net Zero (DESNZ), which contain two main case studies: a "Base Case" that assumes only currently planned projects are available [3], and a "High Electrification" scenario that explores reaching net zero by 2050 in Annex O [4].

Renewables, particularly wind and solar PV, have become the cheapest way to generate electricity, and as such there are plans to increase the capacity of wind and solar. However, there remains the problem of finding sufficient energy sources to fill in the electricity supply when wind and solar are not available, and as a result (under the current pricing system), wholesale prices remain high despite cheap renewable generation costs [5]. Supporting generation options must also be low-carbon if net zero targets are to be met. Energy storage is one proposed solution to intermittency, but this can be expensive and there are likely to be challenges in building enough capacity. This report analyses the costs and practicalities of these scenarios and explores whether cheaper, more resilient, and less carbon-intensive options are possible by better utilising nuclear energy (i.e. both nuclear-generated electricity and heat).

This report is written from the point of view of the current UK situation on implementing measures for achieving net zero and uses historic data and published projections in its economic assessment. The results are however applicable to other developed countries, which have the capability and option to use nuclear energy at scale.

The main part of the report establishes the basis of the analysis and presents the results. In particular, in Section 4 we outline an alternative "Flexible Nuclear" scenario, which combines high levels of low-cost wind and solar power generation, whilst minimising overall system costs by using the heat from the generation of nuclear electricity more effectively than at present.

Appendices 1-3 give the details of the analyses on the DESNZ scenarios and our alternative Flexible Nuclear scenario, based on the use of nuclear cogeneration and AMR thermal storage technology. Appendix 4 discusses curtailment in more detail. Appendix 5 discusses a wider range of technologies (some newer), beyond VRE and nuclear which have the potential to make a positive contribution to a reliable, low-carbon electricity grid. Appendix 6 provides detail on nuclear hydrogen production, while Appendix 7 explores nuclear flexibility and thermal storage in more depth.

# 2 Background

## Definitions

Prior to this discussion, there are some terms which should be defined. Some are technical terms which may not have common usage and so warrant defining, and some have multiple definitions or are used interchangeably with other terms, in which case clarity on our use henceforth is necessary.

## Energy Production Terminology

Depending on the source material, terms such as "capacity factor" can have various definitions with subtle differences and are often used interchangeably with "load factor" and "utilisation factor". Given the nature of the subject matter, such distinctions are important and our definitions throughout are thus:

- The **installed capacity** of an electricity generator is the maximum power it can generate, reported in watts.
- The **load factor** is a measure of instantaneous generation, relative to the installed capacity. This is usually given as a percentage, but fractional or decimal notation is also sometimes used.
- The **capacity factor** is the average generation, relative to the installed capacity over a period of a year (unless a different time period is specified). This is usually given as a percentage, but fractional or decimal notation is also sometimes used.
- **Curtailment** is defined as the fraction of the available generation that is diverted or rejected from the grid. This includes avoided generation, which occurs when generators are requested to cease generation by the grid operator.

Consider a generator with an *installed capacity* of 100 MWe. If at a given instant, it is generating and delivering 20 MWe, its *load factor* is 20%. If over a year, the average output is 40 MWe (i.e. its average *load factor* is 40%), its *capacity factor* is 40%.

- **Cogeneration**, sometimes referred to as Combined Heat and Power (CHP), is when useful heat is delivered from a thermal power station in addition to electricity. This would include the use of heat in district heating, or for use in industrial applications such as hydrogen production. In this report cogeneration is used to distinguish direct applications of heat and power to a range of low-carbon related uses, from electricity supplied to support the grid.
- **Dispatchable power** is defined as power that can be made available at any time it is required, usually electricity generation from rotating generators in thermal or hydroelectric plants.
- **Thermal plants** use heat energy to generate electricity. The heat can come from a range of sources, such as combustion, nuclear, geothermal or concentrated solar energy.

- **Variable Renewable Energy** (VRE) is a collective term for renewable energy which has variable output – this variation is sometimes predictable (e.g. solar or tidal), and sometimes less predictable (e.g. wind). VRE therefore cannot be relied upon as dispatchable. VRE includes wind, solar, tidal and wave power. Geothermal and hydroelectric power are renewable but are not variable, so are considered dispatchable power generators.
- **Baseload** is the minimum level of demand made on an electricity grid over a given time period, not a measure of supply. An equivalent amount of supply to meet baseload demand has historically been provided from dedicated generators which are cheap to operate – typically nuclear and coal power.

Usually, a distinction between "energy" and "electricity" is helpful in discussions such as these. However, "VRE" is a widely used term and specifically refers to "energy" (as the variability is inherent in the energy source); this of course translates into variable electricity if the energy is used to generate electricity. In the UK, use of VRE for non-electricity applications is limited to a very small contribution from solar heat for water heating, with almost all VRE used for electricity generation. A distinction between the two is explicitly mentioned where we feel it is needed.

## Nuclear Systems Terminology

- **Light Water Reactors** (LWRs) are, in this context, usually large gigawatt-scale reactors moderated and cooled by light water. These make up the majority of power reactors around the world. Sizewell B and Hinkley Point C are LWRs, specifically **Pressurised Water Reactors** (PWRs) – the most common type of LWR.
- **Small Modular Reactor** (SMR) is reserved specifically for small, modular LWRs. Some define these as being below a maximum electrical power output of 300 MWe [6, p. 2], but such a limit is not the case in the UK where the ability to be manufactured off-site, then delivered and assembled is key.
- **Advanced Modular Reactor** (AMR) is the collective term given to reactor designs which are modular in construction but deviate from the light water cooled and moderated specification. **High Temperature Gas-cooled Reactors** (HTGRs) are an example of an AMR, and are considered in the UK, China and Japan those closest to implementation and as such are the focus of AMR development in the UK [7]. A detailed discussion of "HTGR as the AMR of choice" is available from [8].

## Financial Terminology

Economics are a crucial consideration when considering new energy infrastructure. Readers may find the following definitions useful:

- **Overnight capital cost** is the cost of a construction project if no interest was accrued during the construction period (i.e. if the entire project was delivered "overnight").
- **Fixed costs** are costs that are incurred irrespective of the extent of goods or services provided. An example would be the rent on a commercial property, which must be paid whether the enterprise is operating at full or zero capacity.
- Conversely, **variable costs** are costs that scale with the degree of output. In energy, fuel is a typical example.
- **Levelised Cost Of Electricity** (LCOE) is the average cost of electricity produced by a generator over its lifetime. It includes the overnight capital cost, interest accrued during construction and operation, and all fuel and operations costs. Calculating LCOE relies on many assumptions, such as the capacity factor which will be achieved over the lifetime, and the cost of borrowing or the expected return for investors.

## 2.1 Electricity Trends in the UK Since 2000

The development of the total installed UK electricity capacity over the last 23 years is shown in Figure 1, along with the changes in demand. Installed capacity is a key metric in understanding the dynamics of the UK energy system.

In 2000, the installed electrical capacity in the UK totalled around 80 GW, dominated by fossil fuel generation. This compared to peak demand of just under 65 GW (i.e. around 80% of total capacity). As concerns began to build about the need to reduce $CO_2$ emissions in the years since, a sizeable amount of wind and solar capacity was installed. By 2023, peak demand had reduced to under 50 GW, due largely to increased efficiencies and decline of heavy industry. Despite this fall in demand, the total installed capacity had increased to over 115 GW with increased reliance on Variable Renewable Energy (VRE). Because of the intermittent nature of VRE, a greater degree of standby capacity for periods of low VRE output is required.

As Figure 1 shows, the last two decades have been a key transition period where renewable generation went from a trivial to a sizeable share of total installed capacity. Over the same period, coal and oil capacity was heavily reduced, and increasingly used only for last resort dispatchable electricity at times of high demand, and natural gas capacity continued to expand as part of the coal-to-gas transition which the UK has experienced since the early 1990s. Natural gas capacity has not reduced as VRE capacity increased in recent years. Nuclear power capacity has decreased since 2000 due to Magnox and AGR stations being retired, without replacement plants coming online in the meantime.

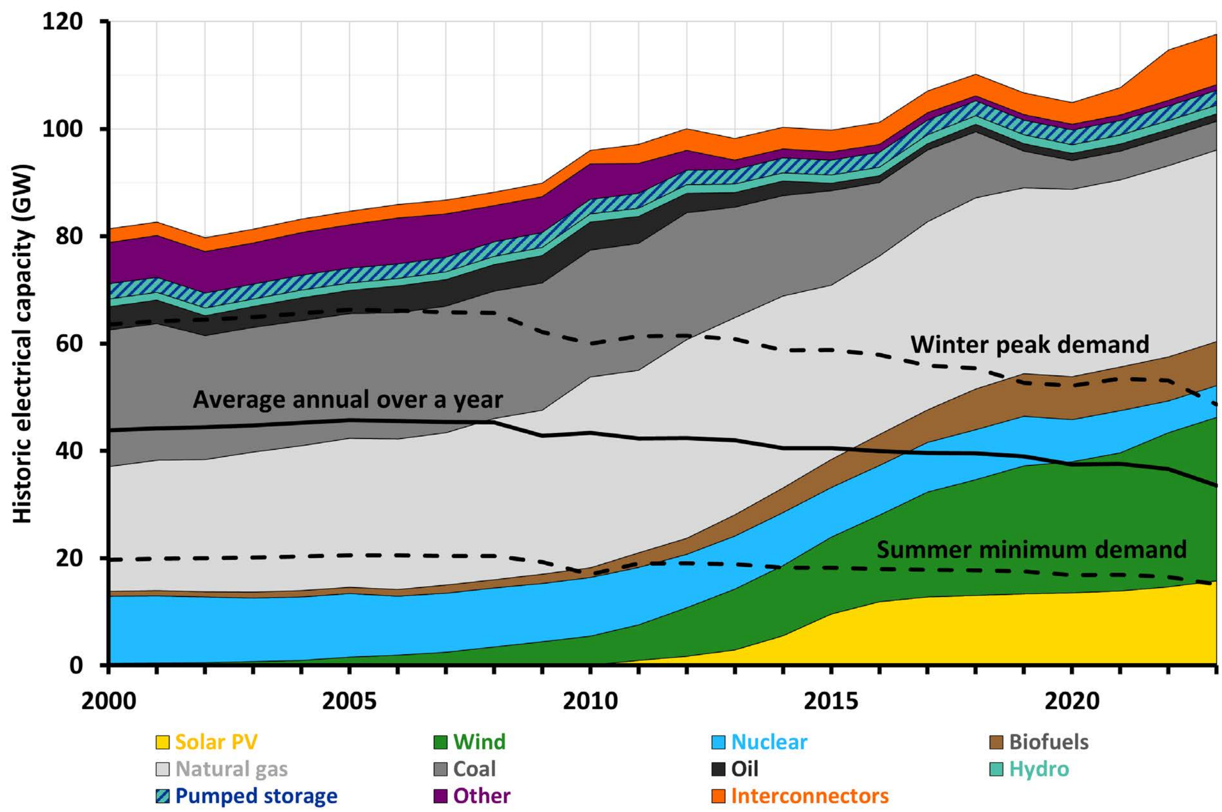



**Figure 1. Historic variation of the makeup of UK electrical capacity from 2000 and the calculated average demand over the year [9] and estimated peak and minimum demands.**

After installed capacity, the second important metric to consider is generation. Not all the available capacity is needed to meet demand, so the actual supply from generators into the grid and onto consumers is adjusted accordingly. Figure 2 shows the make-up of UK electricity generation over the same 23-year period. While total installed capacity has been expanding, generation and supply have been contracting since the financial crisis of 2007/8. This is a result of several factors such as energy saving, (e.g. improvements in insulation and the introduction of LED lighting), the continuing de-industrialisation of the UK, lower economic growth, and high energy prices.

In 2023, oil and coal capacity still exist, but they provide vanishingly small amounts of generation. The replacement of coal with gas since the early 1990s has contributed to early decreases in $CO_2$ emissions from UK electricity generation.

The recent decrease in electricity generation is unlikely to persist, with up to a threefold increase anticipated by 2050 [10, p. 125]. As efforts to reduce greenhouse emissions increase, a substantial amount of primary energy use will shift to electricity, which is easier to decarbonise. This will include replacing some domestic and business heating with heat pumps, increased electrification of rail transport and road vehicles, manufacture of synthetic fuels and a range of higher temperature applications using resistive heating, electric arcs and microwaves [11].

## 2.2 Government Power Sector Scenarios

Government, via DESNZ, has developed scenarios [3, 4] which model potential pathways for meeting future power needs for the UK.

The DESNZ Base Case scenario, Annex A in [3], is a projection of the UK electricity capacity and generation

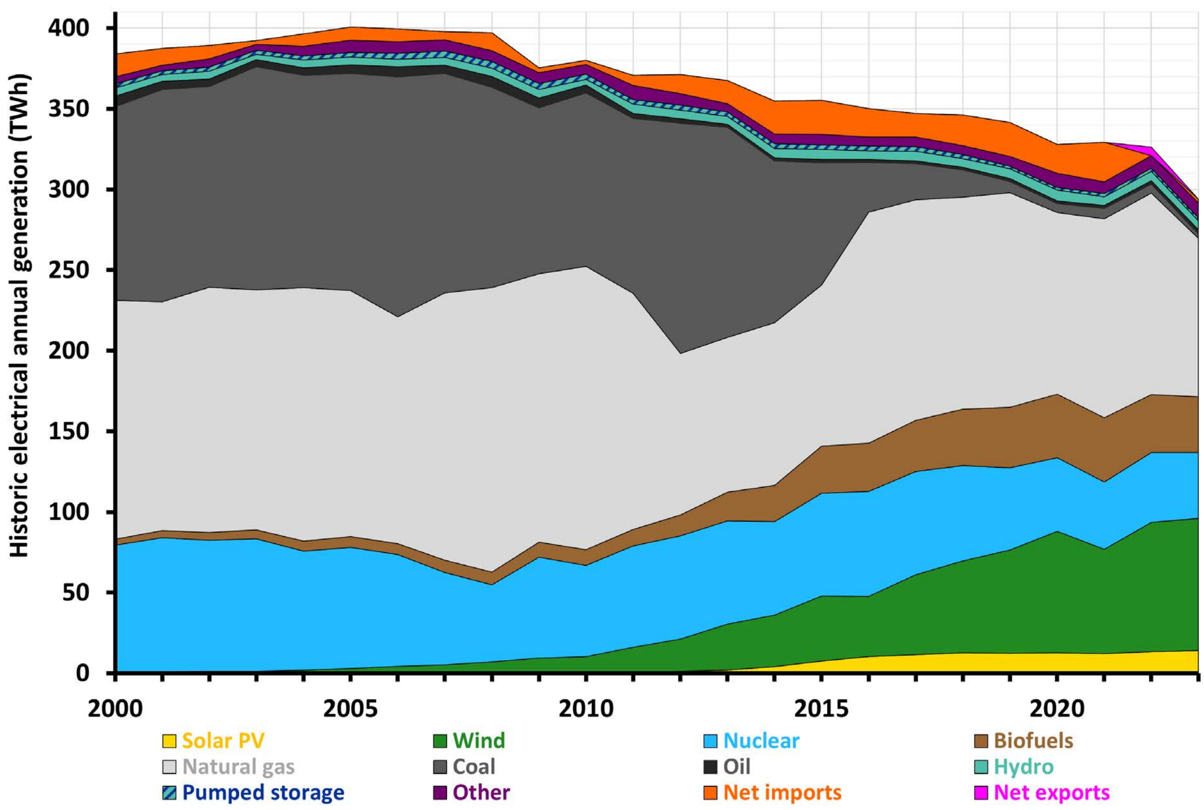



**Figure 2. Historic variation of the makeup of UK electrical generation from 2000 [9].**

composition to 2040 on the assumption that only existing technologies and approved projects are used. It does not include the expected increase in demand for electricity for transport, heating, and industry required to reach net zero. As such it does not include the associated large increase in renewables, nor the associated requirements in respect of backup capacity needed for their integration.

The proposal for reaching net zero in the UK is described in the report "Powering Up Britain" issued by DESNZ in March 2023 [12], with supporting data given in Annex O of the "Energy and Emission Projections" issued at the same time [3, 4]. Two scenarios were provided: a Low and a High Electrification scenario. The High Electrification scenario assumes high levels of electrified road and rail transport, and heating of homes and businesses. Most generation comes from renewables, with a large installed capacity of gas plants, with total electricity demand in 2050 at 792 TWh/yr and 140 GW average electrical power over a year (592 TWh/yr and 106 GW for the Low Electrification scenario).

The High Electrification scenario has been examined closely in this paper as it reflects the large increase of wind and solar power necessary to reach net zero at a low cost, at the same time highlighting the associated need for supporting generating capacity to accommodate the times when solar and wind are not available. It also reflects the "Powering Up Britain" report [12] and statements made by the (then) Prime Minister and Energy Security Secretary in March 2024 for plans to extend the use of unabated natural gas to generate electricity and to build a new generation of gas power stations [13, 14].

The costs associated with supporting a VRE-heavy grid can be very high [15, 16]. The costs associated with the Base Case and High Electrification scenarios are examined in Appendices 1 and 2 respectively, using data from DESNZ and its predecessor, the Department for Business, Energy and Industrial Strategy (BEIS). The main source documents are Chapter 5 on Electricity of the Digest of UK Energy Statistics 2023 [9], the Electricity Generating Costs reports 2020 [17] and 2023 [18], and the Updated Energy and Emissions Projections 2023 [3, 4].

One important omission from current Government scenario modelling is the potential deployment of AMRs – particularly HTGRs – with associated hydrogen generation. The development and use of AMRs is part of DESNZ planning, envisaging an HTGR demonstration reactor for the early 2030s [19, p. 20], but they are yet to be included in official scenarios. This gap is filled by this current study, which (because of the anticipated rise in electricity demand to 2050) adapts the High Electrification scenario, replacing unabated* gas with nuclear power as the means of accommodating shortfalls in electricity supply. Appendix 3 lays out this new Flexible Nuclear scenario.

### 2.2.1 **Net Zero High Electrification Scenario**

Because of the expectation that electricity demand is going to increase in coming years, our focus is the High Electrification scenario. Most technologies are fully defined in the scenario [4], but wind and solar are not defined separately from other renewables. Some fixed points are provided elsewhere [12], so some interpolations and extrapolations have been necessary to get a complete picture of the makeup of the electricity capacity and annual generation. Table 1 lists the fixed points in black.

This scenario involves delivery of very large amounts of wind and solar capacity by 2050, but their combined share drops to 58% of the UK's overall installed electricity capacity because of unabated natural gas capacity more than doubling over the same period. The contribution to generation from solar is small relative to the installed capacity as the capacity factor is typically around 10-11%. [20]. The relatively low levels of storage embodied in this scenario means that curtailment of wind and solar is likely. In particular, some of the solar generation is likely to be curtailed, as a large proportion of it is in the summer (when demand is lowest), so the capacity factor of solar is reduced to 8% from 2035. In 2050 it is anticipated that with improvements in technology, onshore wind could achieve a capacity factor of 48%, and offshore wind 69%, however this is not reflected in the data from the scenarios (Table 1 – page 17), which point at lower capacity factors.

Provision of supporting generation for periods when VRE is not available for longer periods is a key issue. The supporting generating capacity must be large – similar to the VRE capacity itself, or the highest expected demand. While the capacity/load factor over the year may be low, part of it must be able to be sustained for periods of weeks at a time, although there may well be considerable variation in both VRE supply and demand during such periods. This is the cause of the most striking numbers from Table 1 – those for unabated natural gas in 2050. In 2050, this scenario predicts unabated natural gas generation represents 11% of the total cost of generation yet delivers just 1% of the electricity, at an effective cost in excess of £1000/MWh. This is despite the considerable increase in installed capacity to 2050 (i.e. tens of gigawatts of new gas plants would be built with the expectation that they will operate with a capacity factor of only 1.2% in 2050). This scenario is discussed in more detail in Appendix 2.

* ***Unabated*** *refers to fossil fuel combustion where no efforts have been made to reduce the amount of resulting* $CO_2$ *emissions released into the atmosphere.*

**Table 1. Key targets to 2050 for the DESNZ High Electrification scenario [4, 12] to reach net zero. Numbers in *blue* are rounded interpolations from the main fixed points, or estimations as separate values for wind and solar generation are not provided in the DESNZ scenario.**

| Source | | 2030 | 2035 | 2040 | 2050 |
|---|---|---|---|---|---|
| Solar PV | Installed capacity (GW) | *44* | 70 | 77 | 90 |
| | Generation (TWh/yr) | *39* | *49* | *54* | *63* |
| | Capacity factor (%) | *10* | *8* | *8* | *8* |
| Wind (onshore and offshore) | Installed capacity (GW) | *60* | *110* | 124 | 151 |
| | Generation (TWh/yr) | *226* | *369* | *425* | *520* |
| | Capacity factor (%) | *40* | *38* | *39* | *40* |
| Nuclear | Installed capacity (GW) | 4.5 | 9.5 | 14 | 24 |
| | Generation (TWh/yr) | 38 | 56 | 94 | 180 |
| | Capacity factor (%) | 97 | 67 | 75 | 85 |
| Carbon Capture and Storage (CCS); natural gas and biofuels | Installed capacity (GW) | 4 | 11 | 14 | 20 |
| | Generation (TWh/yr) | 15 | 34 | 36 | 47 |
| | Capacity factor (%) | 48 | 36 | 29 | 28 |
| Hydrogen power | Installed capacity (GW) | 5 | 5 | 18 | 45 |
| | Generation (TWh/yr) | 9 | 8 | 11 | 9 |
| | Capacity factor (%) | 22 | 18 | 7 | 2 |
| Unabated natural gas | Installed capacity (GW) | 38 | 63 | 79.5 | 84.5 |
| | Generation (TWh/yr) | 12 | 5 | 5 | 9 |
| | Capacity factor (%) | 3.5 | 1.1 | 0.9 | 1.2 |
| **TOTAL** | **Installed capacity (GW)** | **155.5** | **268.5** | **326.5** | **414.5** |
| | **Generation (TWh/yr)** | **339** | **521** | **625** | **828** |
| | **Greenhouse gas emissions ($MtCO_2eq/yr$)** | **14** | **9** | **4** | **1** |
| Storage (pumped hydro and batteries) | Installed capacity (GW) | 5 | 5 | 15 | 15 |
| | Supply (TWh/yr) | 12 | 31 | 33 | 33 |
| | Capacity factor (%) | 25 | 21 | 26 | 26 |

## 2.3 Greenhouse Gas Emissions

The purpose of the Net Zero Strategy is to eliminate greenhouse gas emissions as far as possible. Figure 3 shows the decrease in greenhouse gas emissions associated with the elimination of coal generation in favour of gas and the rise in renewable energy. The graph shows historic data and future projections arising from the Base Case scenario. The retention of unabated natural gas generation, without introduction of sufficient low-carbon alternatives results in no further decrease in emissions projected beyond 2030.

Any industrial or energy production activity results in net emissions of greenhouse gases, which occurs during combustion of fossil fuels, but also as part of lifecycle emissions*. This means that in addition to the emissions shown in Figure 3, there are the lifecycle emissions from the carbon footprint of the technologies to produce the electricity, including emissions which arise outside the UK. These emissions also need to be considered to give a complete picture. Figure 4 (page 19) provides an overview of overall lifecycle greenhouse gas emissions from the United Nations Economic Commission for Europe (UNECE) [22].

There are some processes which can provide a net negative carbon output, and deployment of some of these will be necessary to fully achieve net zero, as some emissions will remain unavoidable. For example:

- Combustion of biomass releases $CO_2$, however the growth of the biomass uses $CO_2$ from the atmosphere to grow the fuel material, so the process can be considered carbon neutral. If however, the $CO_2$ from combustion is captured the overall process can be carbon-negative, so long as attention is paid to the sustainable nature of the biomass, and the carbon capture process. BioEnergy with Carbon Capture and Storage (BECCS) is part of the Government's Net Zero Strategy.

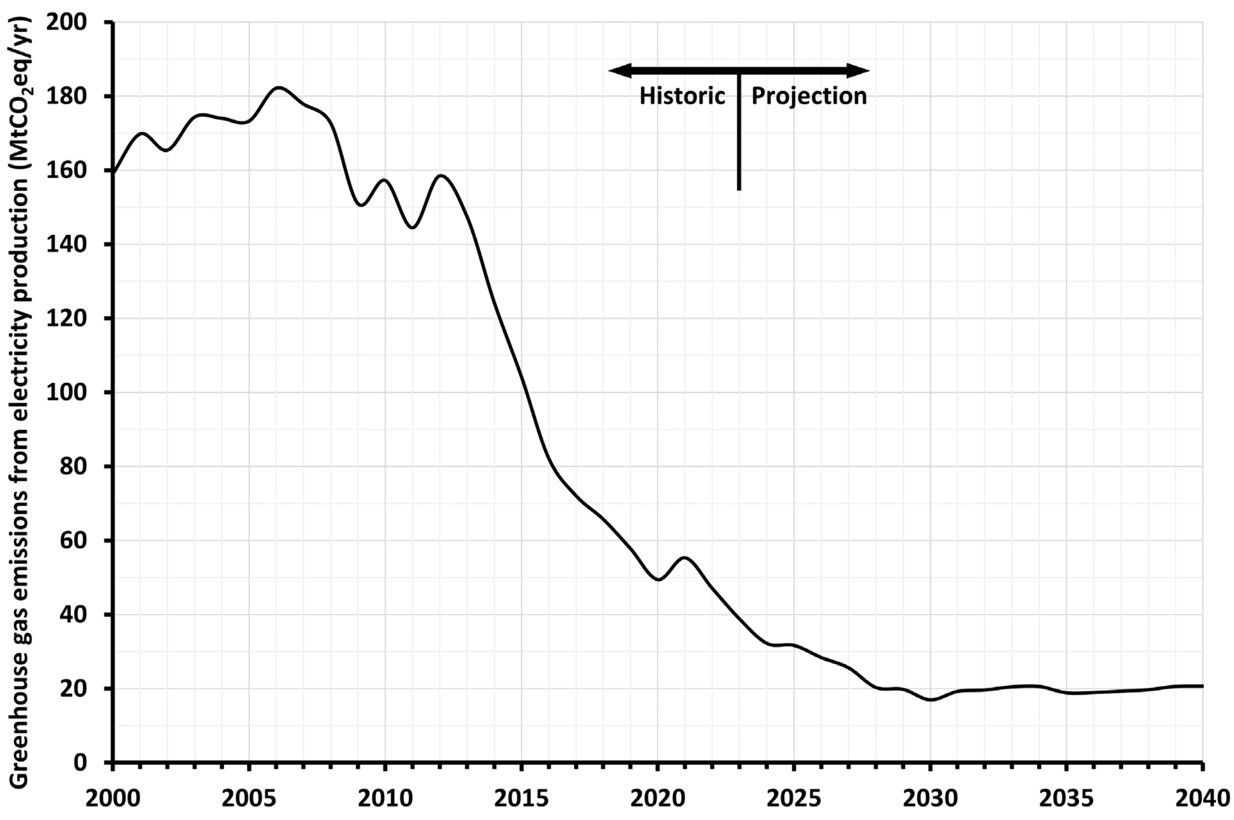



**Figure 3. Greenhouse gas emissions from historic and Base Case projections [21].**

* ***Lifecycle emissions*** *are the total emissions which arise from the activity in delivering energy. Nuclear and renewables are sometimes referred to as "zero carbon" or "carbon-free" because there are no greenhouse gas emissions at the point of generation, however there will always be emissions from construction, decommissioning, repair, materials extraction, manufacturing etc. These are difficult to quantify exactly, but reliable estimates are essential if fully informed decisions are to be made on absolute emissions reductions.*

- An additional, very direct method of reducing $CO_2$ burdens is direct capture of $CO_2$ from the atmosphere, followed by CCS or use in synfuel production. UK trials of this approach are being planned, for example as part of the Sizewell C project.

### 2.3.1 **Carbon Pricing**

One approach to reduce emissions is the imposition of carbon pricing methods, which are designed to compensate for the carbon detriment of an activity. These usually take the form of an Emissions Trading Scheme (ETS), such as the EU ETS from 2005, or the UK's own ETS following its exit from the EU; or a straightforward tax on carbon emissions deriving from services and manufacturing.

Of course, the relative importance of the carbon detriment varies markedly with the energy generation used. This is illustrated by the data shown in Figure 4. This also gives a good indication of the generation methods that could be employed to give a low-carbon detriment for the very high electricity and energy programmes that are being envisaged to achieve net zero by 2050.

Carbon pricing has become an established fixture, contributing to overall energy prices in many economies which wish to reduce emissions and therefore needs to be considered in modelling. The extent of carbon pricing is however an arbitrary addition so modelling and scenario development should acknowledge its impact in the calculations and assessments being carried out.

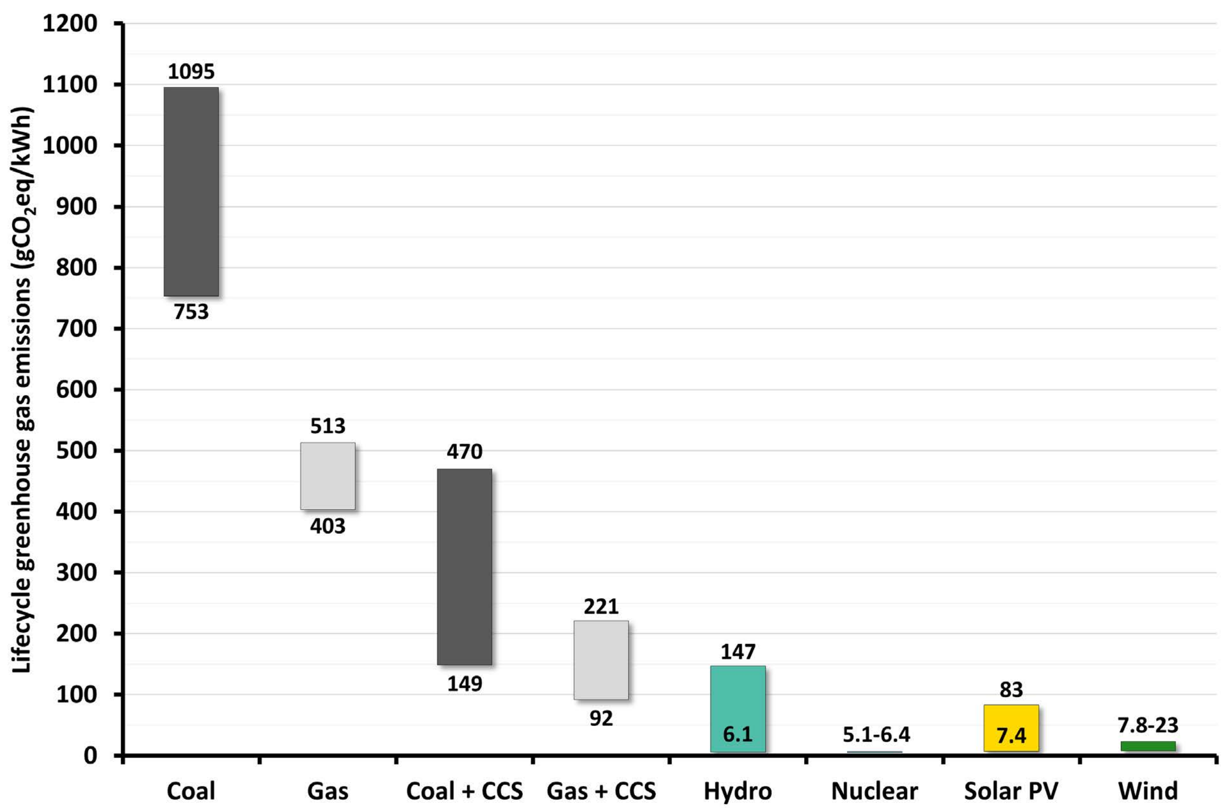



**Figure 4. Lifecycle greenhouse gas emission ranges for technologies assessed by UNECE. Adapted from [22, Fig. 1].**

## 2.4 What Drives Energy Costs?

The areas of expenditure for different technologies vary substantially. A useful metric for comparing costs of generation is the Levelised Cost Of Electricity (LCOE) – the overall cost of generation per unit output over the plant's lifetime. Absolute calculations of LCOE for different technologies vary based on a range of assumptions, but in this section the focus is on how the costs vary with capacity factor. What is important for this discussion is proportionally where the costs are expended, and particularly between fixed costs such as construction and financing, and variable costs like fuel. Two key cost considerations are illustrated below.

### 2.4.1 Investment Costs

Firstly, there is the role of investment costs. Figure 5 shows the typical cost breakdown for large nuclear. From this it is clear how the cost problems with gigawatt-scale nuclear arise; the very large initial investment cost results in a sizeable build-up of interest over the long build times during which no income is generated. The costs associated with operation and fuel are minor in comparison. The long lifespan and large power output of nuclear plants makes their LCOE competitive with other generation methods, but this does little to alleviate the financial burden prior to connecting to the grid. To reduce the overall cost of nuclear power, current areas of focus are on reducing the capital cost and shortening the build time (thus limiting the interest costs) – two motivators for the drive to develop SMRs. The breakdowns for VRE options are broadly similar, i.e. dominated by investment costs due to their lack of fuel during operation. However, the cost hurdle in absolute terms for VRE investors is much lower, due to the greatly reduced capital costs compared to large nuclear.

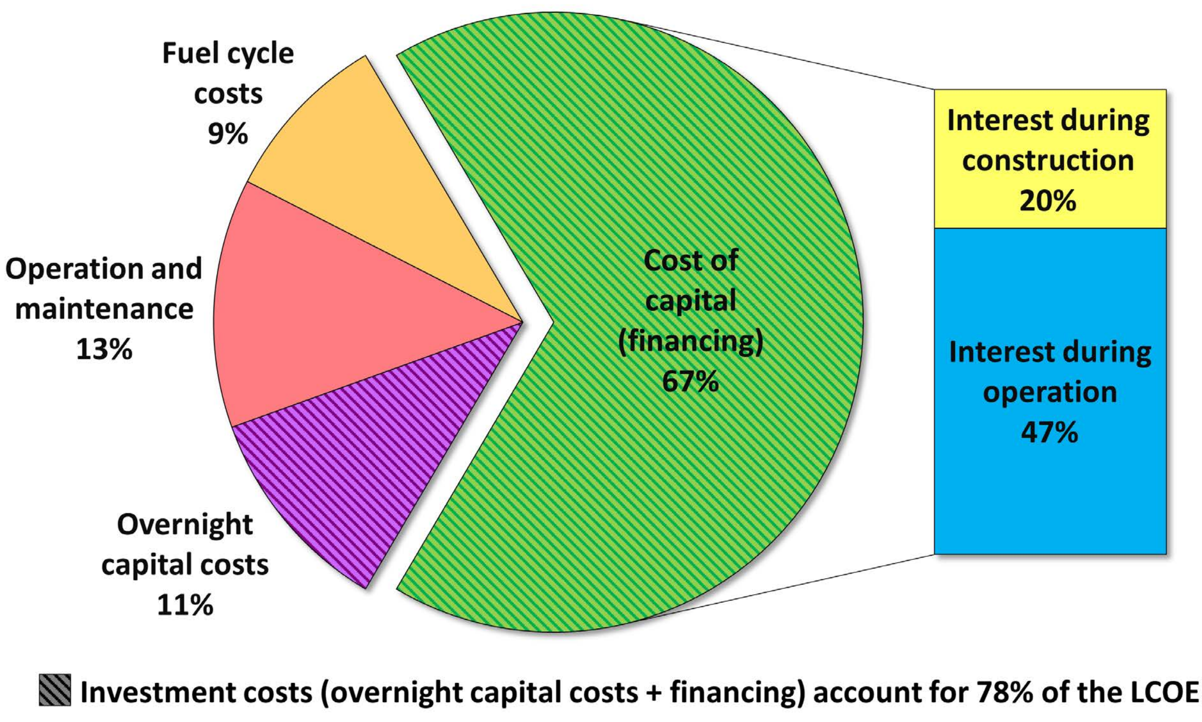



**Figure 5. Typical costs breakdown for gigawatt-scale nuclear, assuming a 7% discount rate. Reproduced from [23].**

### 2.4.2 **Capacity Factor**

The second consideration in relation to LCOE is the role of capacity factor. Figure 6 shows a breakdown for a Combined Cycle Gas Turbine (CCGT) plant operating at two very different capacity factors. At high capacity factor (the figure of 93% is the reference figure used in BEIS/DESNZ cost tables [17, 18]), the cost of fuel dominates, making up over 75% of total costs. However, the same plant, operated only 1.2% of the time, gives a very different cost breakdown, similar to that of the nuclear plant in Figure 5 in the sense that it is largely dominated by capital and financing costs, with fuel costs becoming a minor part of the total cost. The lower capacity factor of 1.2% is especially relevant because it is the anticipated value for gas plants in the DESNZ High Electrification scenario by 2050 (see Table 1).

The charts in Figure 6 illustrate the stark change in the LCOE breakdown which occurs when reducing the capacity factor of otherwise identical plants. The total cost per unit of electricity generated is indicated by the area of the chart. Whilst the contributions of fuel and variable O&M costs to overall LCOE remain the same, the contribution from fixed costs increases substantially as capacity factor is reduced to very low levels. Class H* CCGT plants with anticipated capacity factors at this very low level appear in the DESNZ scenarios and so this calculation will be revisited in Appendix 2.

In the case of nuclear power, the very high capital cost of the plant requires a large portion of the generation cost to service this capital cost. This means that, to optimise the generation cost, the reactor must be in operation for

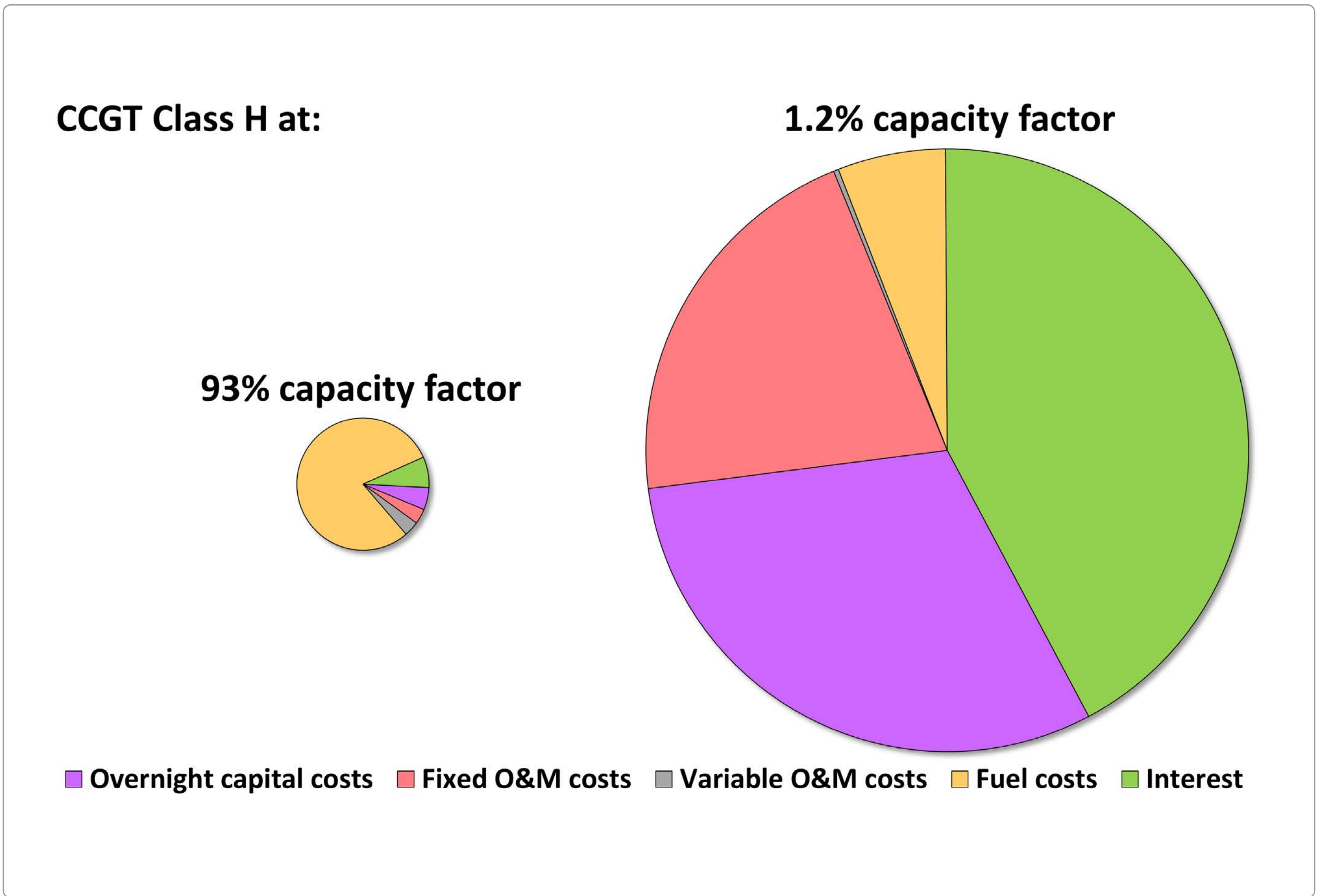



**Figure 6. LCOE cost breakdown (excluding carbon pricing) of a typical CCGT gas plant, depending only on its capacity factor. The area of the charts is proportional to unit generation cost.**

* ***Class H*** *is a high efficiency CCGT system used in the UK since 2012 and is the reference case used by BEIS/DESNZ [17].*

the maximum possible proportion of the time (i.e. with maximum capacity factor), as running at a lower capacity will give a major increase in the unit generation cost. This consideration, along with physical constraints on reactor operation (explored in more detail in Appendix 7), has historically caused nuclear energy to be designated as "inflexible", and to be given its traditional role of delivering baseload electricity.

Increased LCOE for low capacity factor operation also applies to all other generation methods, but for gas the cost of fuel is relatively much larger and the investment costs smaller. The result therefore is that the increase in generation cost for operating at lower capacity factor will be less marked for gas plants than for nuclear.

**LCOE vs Capacity Factor**

Natural gas has been the main method to support the grid in the years since VRE generation has become important. The variation in the price of gas-fired electricity generation (based on Class H CCGT) with capacity factor is shown in Figure 7, along with the other main methods of electricity generation.

Costs for all generation methods show similar behaviour, because of their associated fixed costs (e.g. capital, land rental, fixed staff costs) as illustrated in Figure 6 (page 21). In all cases, as the capacity factor is reduced the LCOE rises (tending to infinity for a 0% capacity factor).

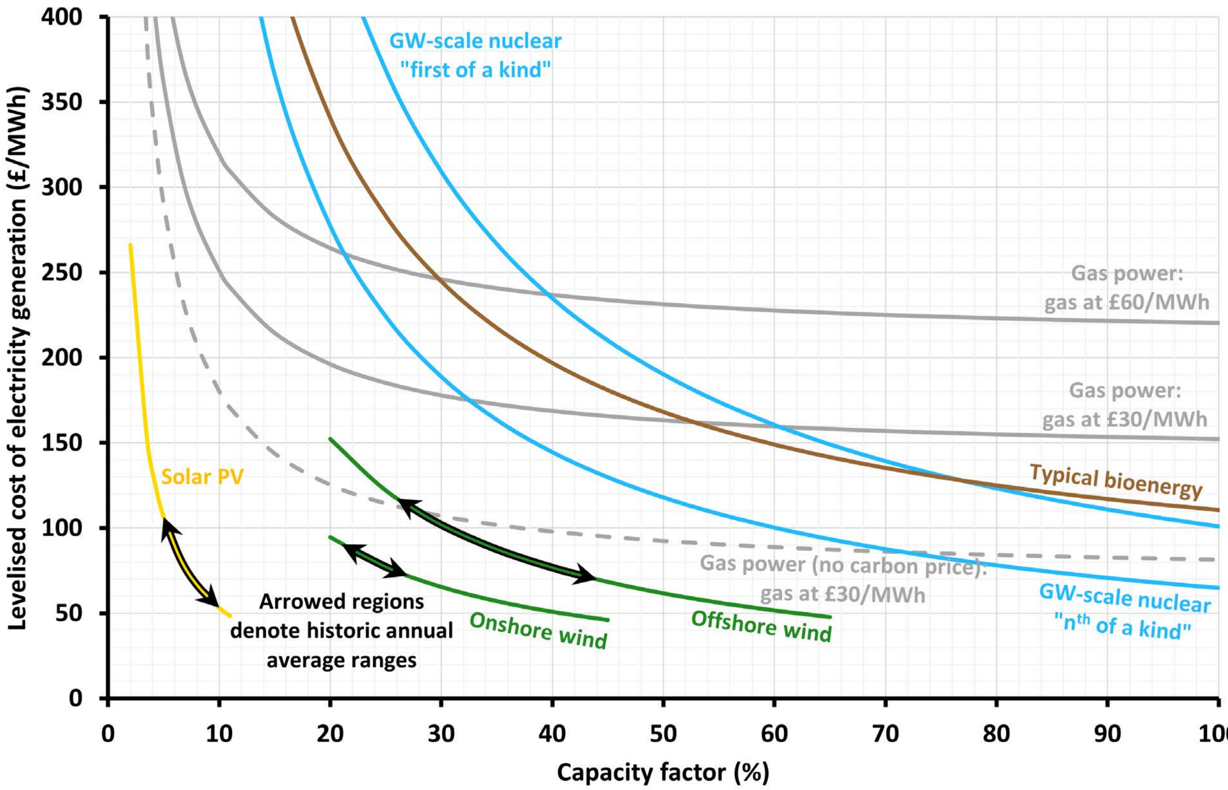



**Figure 7. Comparison of the variation of electricity cost for 2025 (in 2023 money) with capacity factor for the most common electricity generation methods [17, 18, 24].**

In the case of gas-fired electricity generation, the fuel price and carbon price*, which are variable costs, dominate for capacity factors above 30%. By 2025 the carbon price is projected to add ~£60/MWh to the gas price. Capacity factor is also important for solar and wind power, and the historic range of capacity factors for wind indicates that claimed future values are rather optimistic.

Figure 8 shows the effect of wind power expansion on the generation capacity and the associated rise in LCOE of natural gas, indicated by the inverse relation of the blue bar chart with the red lines. Data for this figure are taken from historic UK data and the DESNZ Base Case (discussed in Appendix 1). Two cost calculations for gas LCOE were made:

1. At fixed gas fuel costs to highlight the effect of reduced capacity factor on cost.
2. A more realistic case with variable fuel and carbon prices.

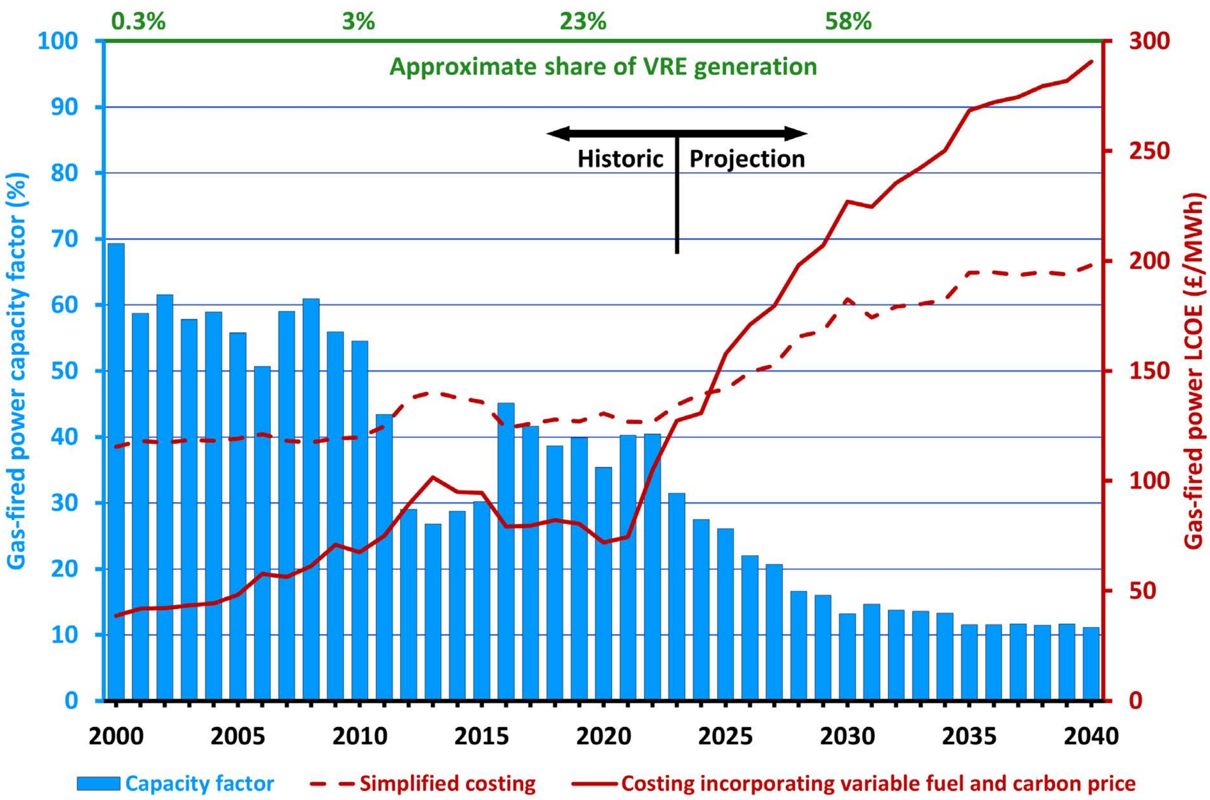



**Figure 8. Chart showing the relationship between the capacity factor of gas and its LCOE (in 2023 money). In this figure:**

Bar chart – Historic and DESNZ Base Case projections of gas generation capacity factor.

Dashed line – LCOE assuming fixed fuel and carbon price to illustrate the relationship.

Solid line – LCOE including changes in gas price and carbon price.

Green axis – Approximate share of VRE at points in time. Data from [3, 17].

* *The carbon prices used for both unmitigated natural gas and with CCS are those used in the latest DESNZ projections on electricity generation costs [18]. These are expected to rise progressively as 2050 is approached, but they are projected numbers and not necessarily what will be imposed.*

In the absence of significant electricity storage capacity, gas power must currently fill in the period when sufficient VRE power is unavailable – this is discussed in detail in Section 3. As VRE installed capacity (and supply) increases, gas provides a progressively lower share of the total electricity supply. The total installed capacity of dispatchable electricity must however remain at least at a similar level to the VRE capacity, or it cannot effectively replace it when none is available (see Section 3.1).

When the VRE share of generation becomes very high, the role of gas generation as part of the general supply mix decreases and is limited to generation only when VRE is not available. This effect is seen with all VRE types, but the higher availability of wind power compared to solar power makes the impact on gas generation more severe [25].

***Recommendation One***

***All energy infrastructure becomes less economically effective per unit of output as the capacity factor reduces. Government decision-making on the future energy mix should consider the capacity factors of new and existing infrastructure, and where these are low, seek alternatives which are potentially more cost effective.***

## 2.5 **Summary of Section 2**

- In the years since 2000:
  - Installed VRE capacity has increased from a negligible amount to over 46 GW.
  - Coal and oil installed capacity reduced from 30 GW to 7 GW. Gas increased from 23 GW to 36GW.
  - Total capacity increased from 80 GW to over 115 GW, however annual generation reduced from 384 TWh to 290 TWh.
  - Electricity demand reduced but is projected to increase in the future as other sectors of society shift to rely on electricity to meet net zero ambitions.
- DESNZ has developed scenarios for the future of energy in the UK:
  - The Base Case projection and High Electrification scenario are analysed in this report.
  - The Base Case projection anticipates a reduction in greenhouse gas emissions to 2030, but no further reduction beyond then due to a residual use of unabated natural gas generation.
- Solar, wind and nuclear power have the lowest lifetime greenhouse gas emissions of those generation technologies currently available.
- Investment costs dominate for VRE and nuclear energy, and these can be prohibitively large in the case of gigawatt-scale nuclear in the UK.
- Plants operated at a lower capacity factor become more expensive per unit of electricity generated.
- The capacity factor of gas generation plants reduces as more VRE capacity is installed, and thus becomes more expensive per MWh.
  - In the High Electrification scenario, this results in unabated natural gas generation contributing 11% of the total cost of generation to deliver just 1% of the electricity, at an effective cost >£1000/MWh.

# 3 Challenges in the Current Strategy

A successful net zero strategy needs to deliver to consumers a robust, cost-effective, and low-carbon electricity supply, via a grid that is resilient to variations in weather and electricity demand. As Figure 4 (page 19) showed earlier, the lowest greenhouse gas emissions per unit of electricity generated by major supply technologies arise from wind, solar, and nuclear energy. Widespread uptake of these technologies however leads to the emergence of very different challenges: the variability of wind and solar, and the cost and the intrinsic inflexibility of nuclear.

No form of low-carbon electricity generation is perfect; each has its issues. Most can be resolved, at a cost, but some are characteristic of the system and must simply be lived with. Solar power in the UK has a low capacity factor, and delivers more energy in summer (when demand is less), and less in winter (when demand is highest). Wind power requires coverage of large areas of land or sea to achieve substantial electricity generation. Onshore wind farms can be unpopular, and offshore wind farms pose a challenging environment for construction, maintenance and decommissioning of large turbines. Nuclear plants carry high capital costs and can also lead to public concerns over accidents and waste. Table 2 (page 26) compares key attributes of some of the relevant technologies.

**Table 2. Comparison of nuclear with renewables and natural gas with CCS technologies [3, 9, 18, 26–29].**

| | Solar PV | Onshore wind | Offshore wind | Nuclear new build | Natural gas + CCS | Unabated natural gas |
|---|---|---|---|---|---|---|
| LCOE 2023 → 2050 (£/MWh)* | 46 → 33 | 51 → 51 | 49 → 51 | 72 → 48† | 89 → 103‡ | 126 → 243‡ |
| Capacity factor 2023 → 2050 (%) | 11 → 11 | 34 → 48 | 55 → 69 | Availability factors up to 95% | | |
| Historic capacity factor (%) | ~10 | ~25 | ~40 | 70-80 | n/a | 24-85 |
| Area required to generate 1,400 TWh/yr ($km^2$)§ | ~29,000 (12% UK land area) | ~152,000 (63% UK land area) | ~48,500 (12% of UK EEZ#) | ~177 (0.075% UK land area) | ~800 (0.34% UK land area) | |
| Emissions ($kgCO_2eq/MWh$) | 43-94 | 20-45 | 9-15 | 7.5-17 | 140-200 | 420-600 |

It is important to not judge the cost-effectiveness of technologies solely on their respective LCOE. VRE generators generally have low LCOE values relative to other technologies, however there are additional system costs which are associated with intermittency (for example the cost of backup or storage) and which become more apparent as VRE makes up a larger proportion of generation. As will be discussed, the overall effectiveness of the whole system must be considered rather than any one metric in isolation.

There are new technologies beyond VRE and nuclear which have the potential to make a positive contribution to a reliable, low-carbon electricity grid. These are beyond the direct scope of this paper, but they are given some attention in Appendix 5. Our attention in this section is focused on the separate challenges faced by VRE and nuclear energy.

## 3.1 VRE Challenges

VRE has become a significant proportion of UK electricity production since 2000 and has expanded rapidly since 2010. 29% of electricity generated in 2022 was from VRE sources (i.e. wind and solar) [9].

Prior to the expansion of VRE, electricity was generated from dispatchable (mostly thermal) sources, which made the mission of the Electricity System Operator (ESO) to ensure electricity supply meets demand relatively simple compared to a modern grid which incorporates large amounts of VRE.

In the UK VRE, which is projected to account for the bulk of 2050 electricity supply, is dominated by solar and wind. In addition to variability, wind and solar also suffer from unpredictability.

The consequence of this variability is that some of the time electricity from VRE is produced when it is not needed, and at other times VRE generation is not available when it is needed. This is not a problem when the level of VRE capacity is small relative to grid demand as it is accommodated by the flexibility of other generators in the system which adjust to meet demand. However, when the installed capacity of VRE becomes increasingly large, mechanisms (with associated costs) will be needed to integrate VRE into the electricity infrastructure.

** LCOE given in 2023 money.*
*† This Nuclear LCOE assumes delivering baseload electricity generation.*
*‡ LCOE for natural gas is higher with the presence of VRE, while capacity factor is much lower. Costs include carbon price estimates.*
*§ 1,400 TWh/yr is the equivalent needed to replace all fossil fuels.*
*# EEZ is the Exclusive Economic Zone, typically an area of the sea extending 200 nmi from the coast of a state, in which a sovereign state has rights regarding offshore wind (among other things).*

The presence of VRE electricity generation therefore requires additional support (either in the form of energy storage or alternative generation) to deliver an electricity grid which meets the criteria of delivering reliable, low-carbon electricity [30, 31].

The need to deliver dedicated solutions to support variable generation (i.e. standby generation, load following, and storage), inevitably leads to reducing the capacity factors of this support, which in turn makes the unit costs of support higher.

The figures below show examples of the problems which arise from incorporating sizable amounts of VRE onto the grid. Figure 9 shows a six-week period of low wind, along with associated electricity demand. The average demand over this six-week period was 26.9 GW, which is similar to the total installed wind capacity of around 25 GW. Average wind generation over the period was 3.3 GW, which equates to a capacity factor over the period of around 13% (this compares to 22% for the whole of 2021 and 26% for 2022 ).

The cumulative energy difference between electricity demand and wind supply over this period was around 23.7 TWh, which of course needed to be filled with alternative generation to maintain grid operation (see Figure 10 later for examples). This figure is worth bearing in mind when considering the storage which would be needed to support a grid reliant entirely on VRE generation. The largest grid battery currently in existence is 0.003 TWh at Moss Landing in California, while the total energy capacity of the pumped storage facility at Dinorwig is around 0.009 TWh. Filling a 23.7 TWh energy gap would therefore require over 2,600 Dinorwigs, or some 7,900 Moss Landing battery arrays. Neither of these options could currently be deemed

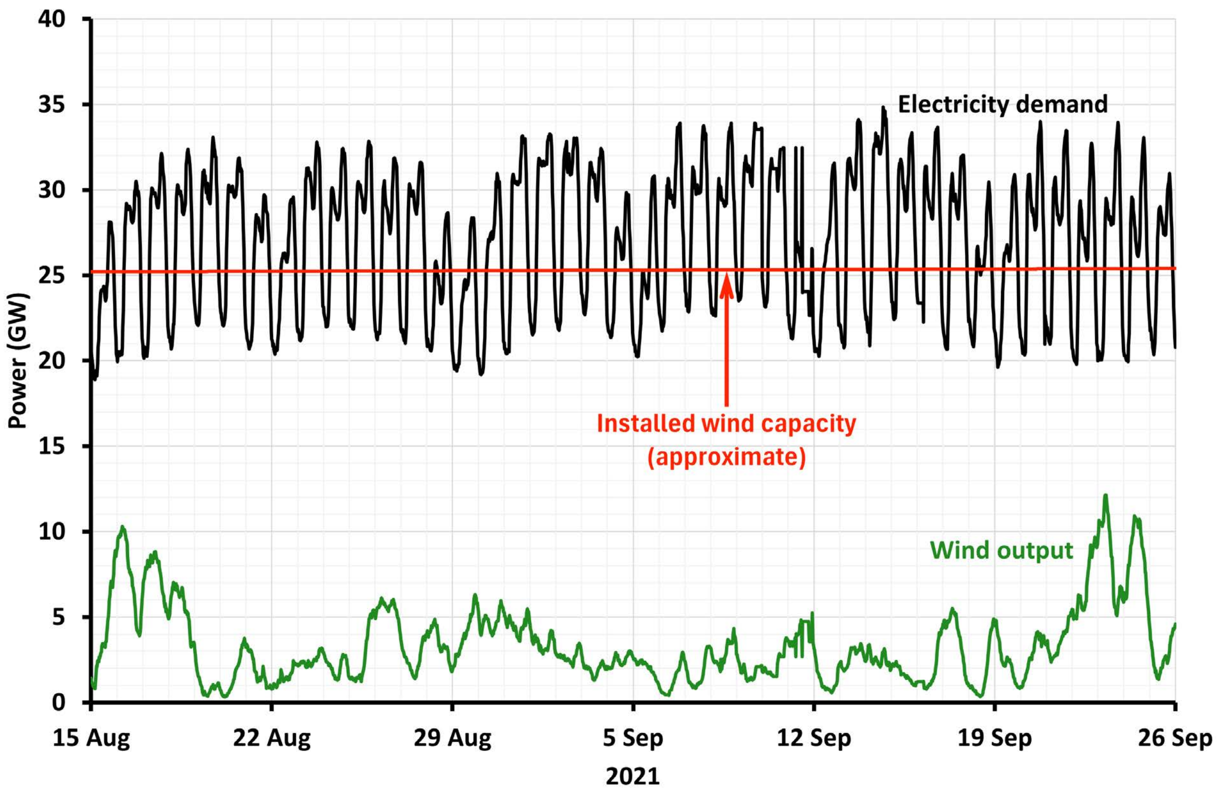



**Figure 9. UK electricity demand and wind generation over a six week period of low wind generation. Data available from [32].**

credible for deployment in the UK, but they provide a useful comparator to help appreciate the large energy demands made by a modern electricity grid, particularly relative to existing energy storage solutions. Accommodating extended periods of low wind using energy storage would require such a prohibitively large expansion of energy storage that any practical approach is likely to place a substantial focus on alternative generation to fill these gaps.

***Recommendation Two***

***Since variable renewable energy generation can experience long periods with little to no output and storage options are limited in scale, Government should ensure that the delivery of low-carbon, cost-effective, dispatchable electricity is prioritised to best support an effective overall system.***

Figure 10 shows two examples of electricity supply by generation source for two individual weeks less than a year apart. These weeks were selected as they each show clear examples of high and low wind within a single week. The maximum wind generation in Figure 10A was 14.1 GW on the afternoon of 3 May (a load factor of around 56%). 18 hours earlier, this was under 0.5 GW (load factor ~2%).

There are two challenges which arise with increasing reliance on VRE:

1. As illustrated above, at times of high electricity demand when sufficient VRE is not available, other sources of electricity need to be provided or the demand reduced.
2. At times of low electricity demand, excess VRE cannot be accepted onto the system and needs to be diverted (i.e. curtailed) from the grid.

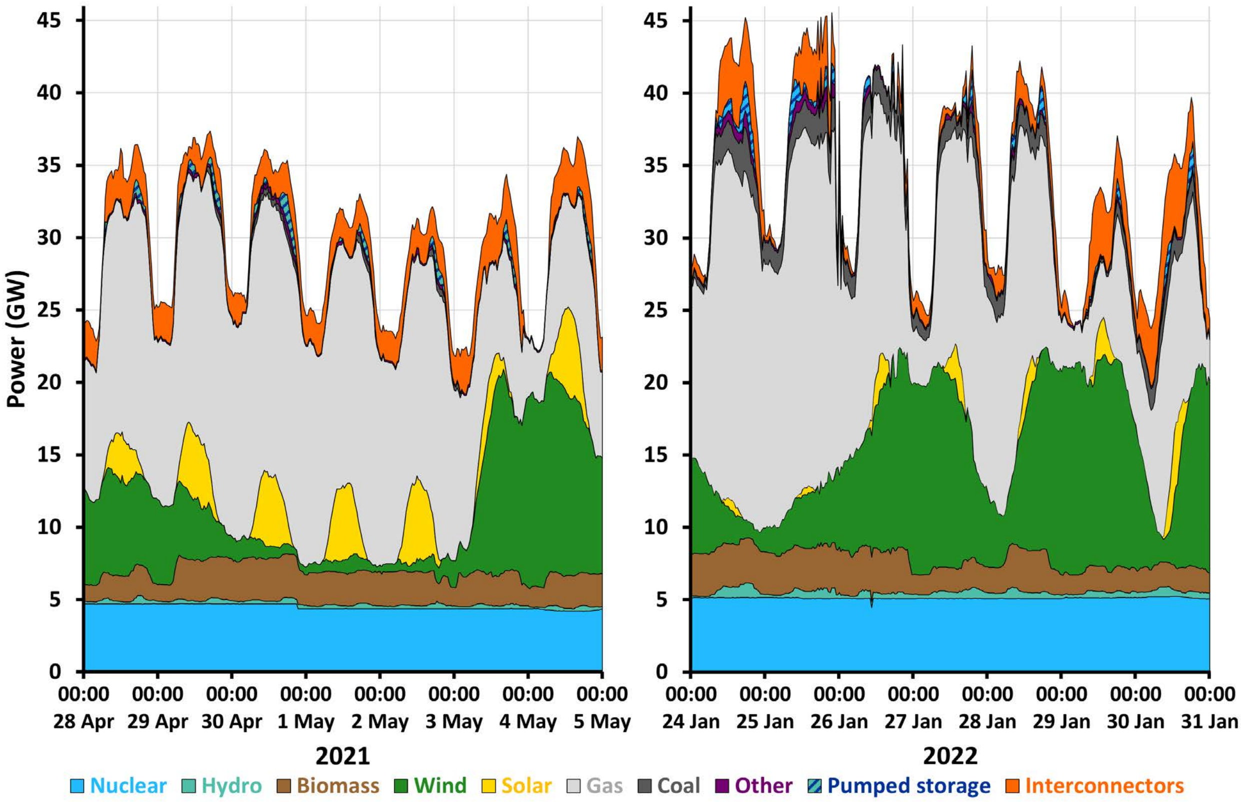



**Figure 10. Energy supply by source over two weeks, one in spring 2021 (A) and the other in the following winter (B). Data available from [32].**

Addressing these two challenges has economic costs.

There are costs associated with providing support when VRE output is low. At present, this issue is managed by procuring energy during periods of low VRE generation from alternative providers which, as the level of VRE in the system increases, will need to operate at reduced annual capacity factor and increased unit price as a result.

Storage is an alternative option, as has been discussed. Battery storage is useful for supporting distribution networks with diurnal cycling (see Appendix 5, Figure 19), but is impractical for the large gaps when VRE generation falls a long way short of demand for significant periods. The capacity of batteries is limited to a few hours, which is good for diurnal cycling, but the cost per stored MWh rises steeply if the batteries are cycled less frequently. Pumped hydro storage can store more, but sites are limited. What is preferable is low-carbon dispatchable electricity and it will be shown later that this can be provided most economically by nuclear cogeneration or by hydrogen generated by nuclear plant.

There are also costs associated with an excess of generation from VRE sources which cannot be handled by the network. This power could – at a cost – be diverted to other applications or stored, but in most cases, it is simply not delivered to the grid. The UK's ESO instructs generators to reduce their output to maintain system operation. Compensation is paid to these generators in the form of "constraint payments" (for a fuller discussion on this, see Appendix 4). As an example, the National Grid paid out £1,015m in compensation for curtailed wind generation for the three years from 2020-2022 [33].

***Recommendation Three***

***As the proportion of variable renewable energy on a network increases, so will the amount of curtailment unless close attention is paid to the whole system. Government should ensure that the inefficiency of curtailment is recognised and that it is minimised as far as possible, for instance by ensuring that large-scale solar power has associated electricity storage.***

## 3.2 **Nuclear Power Challenges**

### 3.2.1 **Nuclear Inflexibility**

In practice, nuclear power as it currently exists in the UK is inflexible. There are two causes for this inflexibility, which has limited its role to that of baseload electricity generator. The first concerns economics and was discussed in Section 2.4. To recapitulate: high capital and financing costs, with long construction times, make for high fixed costs compared to other systems. High capacity factors are therefore needed to keep the LCOE at reasonable levels.

As well as the economic constraints, there are also technical constraints on varying the power output of a reactor, though these vary for different reactor types. The reactors currently operating are thermal reactors, operating with neutrons that are moderated to low energies. Thermal reactors suffer from neutron poisoning, mainly the build-up of the highly neutron-absorbing isotope xenon-135, which has a half-life of 9.14 hours. Reducing the reactor power leads to a build-up of this and other neutron poisons and the reactor can become unresponsive for a few days, which in some designs can lead to safety issues. Cycling the power will inevitably cause damage to the fuel and structures of the reactor through fatigue and ratchetting mechanisms so the rate of power increase, after periods at lower power, must be controlled. These technical issues have led to the practice of load following being avoided by nuclear plant operators.

However, despite these technical and commercial challenges, EDF has been able to achieve significant amounts of load following with PWRs in France. This is necessary because of the large share of nuclear capacity in France, ~70% of total capacity. One measure that has enabled PWR cycling is the use of "grey" absorber rods. Reactor rapid control is achieved using absorber rods. Usually there is a strong depression in power locally around the ends of the rods as they are inserted. By reducing the amount of absorber in the rods, large local variations in power are avoided, minimising the local changes in temperature and neutron flux, and reducing the effects of power cycling [34]. Some AMR designs can cycle more easily, and fast neutron reactors are immune to neutron poisoning.

It is clear that as the UK grid takes on board a higher proportion of VRE in the future, the importance of more flexible dispatchable generation will increase. It is important therefore to consider the possible means by which UK future nuclear plants could operate more flexibly than has been the case in the past.

**Thermal Storage as a Solution?**

There are other avenues to achieve effective flexibility for nuclear energy besides varying the power output of a reactor. An alternative is energy storage (similar to the approach discussed for VRE earlier), and for nuclear plants, one viable technology is the use of thermal storage. The concept draws on experience from concentrated solar thermal power, where it has been proved effective and economic in countries with abundant sunshine. Molten salts are used to store heat in large, insulated silos, and the molten salts are then run though steam generators or heat exchangers [35, 36]. The cooled molten salt is then stored in separate silos to be used in the next cycle. This "solar salt" is a low melting point (~220°C) mixture of sodium and potassium nitrates and nitrites. These are limited to temperatures below 560°C, but there are potentially cheaper salts which can tolerate higher temperatures that could be of use (see Appendix 7). Alternatively, the heat can be stored in large, insulated masses of cheap solid materials such as sand or gravel which are heated and depleted by molten salts [36, 37], but this system has a lower thermal efficiency than the two-tank molten salt option [38].

Using such a setup with a nuclear reactor would allow the reactor to operate continuously, avoiding the problems associated with reactor power variations, and enable drawing of energy from the thermal storage when power is needed. The higher operating temperatures of AMR designs make this a particularly suitable approach.

Several AMR conceptual designs include molten salt thermal storage combined with energy conversion plants up to three times the capacity of the reactor system [39]. At times of low electricity demand, energy is directed to the heat store; at times of high demand, this stored heat energy can be converted into electricity along with the reactor's output. This allows continuous operation of a reactor plant while allowing unrestricted load following, including at very low levels of electricity delivery to the grid. This is an area with potentially large practical application which would enable a considerable degree of flexible useful output from nuclear stations. Considering the financial and practical difficulties in achieving this by other means, such a setup offers the potential of a cheap and effective alternative and should be investigated.

***Recommendation Four***

***Using reactors with thermal storage can potentially offer a cost-effective contribution to solving the problem of nuclear inflexibility. Government should prioritise research to enable an in-depth investigation of the opportunity.***

### 3.2.2 **Costs of Nuclear**

The other big problem with nuclear power is that it has become too expensive. The steady increase in the size of nuclear plants over the years has extended construction times, which adds significantly to the accumulation of interest over the build period. Because of this, despite a recent period of comparative political support for new nuclear power, the UK only has only one new nuclear station under construction (Hinkley Point C) in the period since the opening of Sizewell B in 1995.

The policy to attract any developer that could find investment, would and still could raise the prospect of only one or two power stations using a particular reactor design being built. This would prevent the valuable cost-savings achievable from series construction, and lead to reluctance of the supply chain to invest in the necessary manufacturing facilities. More focus on series build and the use of the Regulated Asset Base (RAB) funding model should reduce financial risk [40, 41].

***Recommendation Five***

***Government, working through Great British Nuclear, should strive to improve the economics of nuclear energy by encouraging fleet build of nuclear plants, with minimal delays, and which are then operated at a high capacity factor.***

**Modular Reactor Designs**

Further decreases in nuclear electricity costs will be enabled by modular construction. SMRs can reduce costs through a series of mechanisms associated with their smaller size and modular construction in factories [42, 43]. SMRs offer the potential to reduce costs of new nuclear plants by:

- Simplifying designs using inherent or passive safety instead of engineered safety features.
- Shortening construction time, which will reduce accumulation of interest during construction.
- Lowering unit investment costs, thus opening up a wider range of investors and a reduction in borrowing rates.
- Co-siting reactors to share facilities and staffing costs.
- Series production, enabling reduction of costs through standardisation of designs, and investment in manufacture and learning.
- Reducing work on construction sites through use of structural and system modules, which are manufactured in factories.
- Use of waste heat for domestic and business applications, providing income and reducing need for dumping of heat.

AMRs create more opportunities in the context of this paper due to their higher operating temperatures. All of the proposed advanced Generation IV systems* have higher outlet temperatures compared to LWRs and SMRs (480-1000°C compared to <300°C for LWRs and SMRs), which allows for greater efficiency for electricity production (40-50% compared to ~33%). However, some of the systems (e.g. HTGRs) can reach the top of the temperature range, providing a greater range of applications and higher efficiencies for electricity generation, hydrogen production, and thermal energy storage.

We have identified earlier how heat can be used as a route to energy storage and thus helping to balance the grid. Heat applications are also important since electricity currently only represents around 20% of total energy use in the UK. While reliance on electricity is expected to more than double by 2050, there will still be a substantial need for new low-carbon heat sources. Current estimates of the cost of electricity from AMRs are that they are similar to SMRs, but some AMR systems have the potential to be cheaper [27]. High temperature AMRs can also provide high temperature heat for industrial applications – thus decreasing the overall energy cost from the reactors.

At first inspection, the data on emissions from different generating technologies in Figure 4 (page 19) are clear: some technologies are clearly "better" than others in reducing emissions. However, as one considers the problem more deeply, it becomes apparent that each of the low-carbon options has challenges which prevent them being a potential sole solution. No one technology can achieve net zero in isolation; it can only be achieved with a complementary set of solutions, involving a portfolio of energy generation technologies. Furthermore, as the grid evolves, the interconnectivity of different technologies becomes more important (specifically how one option can work alongside another to deliver a reliable supply irrespective of the weather or other factors). This is a complex system, therefore:

***Recommendation Six***

***Government's future energy strategies should include full appreciation of effects at the whole system level, comprising generation, transmission, and storage, which must all be developed in parallel.***

## 3.3 Summary of Section 3

- All sources of electricity have drawbacks.
- VRE is dominated by wind which experiences occasional periods of several weeks where generation is very low. Providing storage for a VRE-heavy grid to supply for these periods of low output would be hugely expensive and impractical. Backup generation is therefore needed for such periods.
- When electricity demand is low relative to VRE output, excess electricity from VRE needs to be curtailed. This is wasteful.
- While it is low-carbon and delivers dispatchable power, nuclear in its present large-scale format in the UK is inflexible, which becomes a problem if it is to be present on a grid with large amounts of VRE. Thermal storage for nuclear plants could contribute to addressing this.
- To be a realistic option for large-scale application in the future, nuclear energy must become cheaper to deliver. Modular reactor design, fleet build and new financing models have the potential to achieve this.

* ***Generation IV*** *systems refer to a shortlist of seven different reactor technologies which are the target of R&D among members of the Generation IV International Forum: High Temperature Gas-cooled Reactors (HTGRs), SuperCritical Water Reactors (SCWRs), Molten Salt Reactors (MSRs), Gas-cooled Fast Reactors (GFRs), Lead-cooled Fast Reactors (LFRs), Molten Salt Fast Reactors (MSFRs), and Sodium-cooled Fast Reactors (SFRs).*

# 4

# The "Flexible Nuclear" Solution

A possible solution to the conundrum of filling in the gaps left by VRE during low output (without resorting to the construction of large, dedicated power plants to be run at very low capacity factors) is to use nuclear power for both grid support and cogeneration applications, with most of the output directed at the cogeneration applications. The capacity factor of nuclear energy must be kept high in order to keep costs low, but flexibility is also needed to supply electricity when demand is high and renewable supply is low.

As the planned renewable capacities are scheduled to meet maximum demand, the supporting capacities must also be similarly sized. If net zero is to be achieved, sources of low-carbon energy besides electricity must be delivered for roles which are currently provided by fossil fuels (electricity makes up only around one fifth of energy consumption nationally). Nuclear energy can supply both heat and electricity and this section describes some of the wider potential applications. By building a large nuclear capacity for these cogeneration activities it is possible to divert the nuclear energy to provision of electrical power for the grid very cheaply when needed. In Appendix 7, it is shown that this has the potential to become a very low-cost option provided the total support for the grid over the year is kept to below 20% of the total use.

With higher temperature AMR reactors this approach can be taken further by utilising thermal energy storage, which, as explained in Section 3.2.1, offers a lower cost solution to energy storage. Thermal storage would be a key element of the use of nuclear heat for cogeneration and also decouples the reactor from the electricity generation process. This enables a larger generating capacity to be provided, which would deliver a larger effective capacity for grid support when needed. The costs of doing this would be much lower than providing more dedicated power plants for high levels of demand but with low capacity factors (as is the case in the DESNZ High Electrification scenario described in Section 2.2.1 and Appendix 2). The provision of thermal storage also opens up the possibility of reactor cogeneration industrial sites (i.e. nuclear plants co-located with energy-intensive industrial applications – discussed in more detail in Section 4.1) which could accept excess VRE electricity which would otherwise be curtailed, for applications like hydrogen production and support them with nuclear heat to increase efficiency. It will be shown later that this approach can also reduce carbon emissions.

The Government has recognised the HTGR as the favoured AMR technology for its Net Zero Strategy and is supporting the construction and operation of an HTGR demonstration reactor by the early 2030s. A successful demonstration would allow series build of HTGRs, which in turn could facilitate a robust, economic, low-carbon solution with applications to both the electricity grid and to broader aspects of low-carbon energy use. Some of the applications are discussed below.

## 4.1 Nuclear Cogeneration Potential

### 4.1.1 Hydrogen

The production and use of hydrogen is increasingly being recognised as an important element of decarbonisation. As well as being a fuel itself, hydrogen is a first step in creating synthetic fuels. Hydrogen, unlike electricity or heat, can be stored in significant amounts for long periods and can thus be part of the solution for coping with the variation in energy demand between summer and winter. It was chosen for the present study as the technology for cogeneration to support VRE intermittency issues because the requirement for low-carbon hydrogen production by 2050 is sufficiently high to justify new innovations.

A recent report by NNL with the Energy Systems Catapult and Lucid Catalyst [44] looked at a range of nuclear scenarios to supplement those already produced by the Energy Systems Catapult [45]. These included cogeneration and particularly production of nuclear hydrogen and synfuels. Although not directed at grid support, these scenarios had a beneficial effect on costs and $CO_2$ emissions from the introduction of cogeneration. This report also indicated the benefits from a whole energy system perspective.

Hydrogen can be produced solely with electricity, or with electricity assisted by heat. Where heat is available at low cost, the latter option is more cost-effective, which makes the cogeneration approach especially relevant when we anticipate a future system containing a mixture of gigawatt-scale LWRs, SMRs and AMRs. One important aspect of this is that both high-grade (>500°C) and low-grade heat (<300°C) have their place in getting more out of nuclear plants when it comes to hydrogen generation. Enabling the full potential of nuclear cogeneration will require substantial investment, but we will show below that investment will reduce $CO_2$ equivalent emissions and reduce the overall cost of achieving net zero, whereas retaining the use of fossil fuels with CCS will not. The processes which can be considered for the involvement of nuclear energy are outlined below and discussed in detail in Appendix 6.

Hydrogen is currently produced by the steam methane reformation* or related methane reforming processes, which combine methane and steam to produce hydrogen and $CO_2$. The $CO_2$ produced can be reduced by CCS, but there are residual $CO_2$ and $CO_2$ equivalent emissions from natural gas extraction and usage (see Appendix 6). The hydrogen price from methane reforming is dependent on the price of natural gas.

**Electrolysis**

An alternative to steam reformation is to use electrolysis of water, and this is increasingly attractive as technologies for electrolysis have evolved and improved. The use of electrolysis to utilise otherwise-wasted excess VRE electricity is particularly interesting. While it is possible to produce hydrogen using electrolysis at room temperature, efficiency is vastly improved with access to high temperatures. Progress in the high temperature Solid Oxide Electrolyser Cell (SOEC) technology renders it particularly suitable for use with heat from HTGRs, and it is likely that this will eventually be the cheapest route to hydrogen production, as examined in Appendix 6. Once a low-carbon source of hydrogen is established, this can be a starting point for the production of synfuels†, syngas and ammonia, which opens up a potential pathway for nuclear electricity and heat to help decarbonise several sectors where this is currently very challenging.

A further alternative for hydrogen production utilises thermochemical cycles. Various cycles have potential, and efficiencies and temperature demands vary [46]. While studies have recognised long-term potential for thermochemical cycles, the higher Technology Readiness Level (TRL) of high temperature SOEC makes them more immediately favourable.

### 4.1.2 Other Heat Applications

The potential to use heat from nuclear power stations goes further than high temperature applications for electricity generation and industry. Lower temperature heat from all nuclear technologies could be used to supply district heating for hot water and buildings. Some projects are already in progress, but their scale in the UK is very much smaller than similar projects in progress from existing reactors in other countries. This a clearly an area where efforts in pursuit of net zero should promote broader studies on what is necessary for the future, recognising both the potential for SMRs and AMRs to bring nuclear plants to many new communities and the fact that future reactors may be focused on the production of heat as well as simply electricity. We note that, perhaps due to the historic focus

* ***Steam Methane Reformation*** *has the acronym SMR in much of the hydrogen literature. It is not used here to prevent confusion with Small Modular Reactors.*
† ***Synfuels*** *are synthetic fuels obtained from* ***syngas****, itself a mixture of carbon monoxide and hydrogen.*

on nuclear solely for electricity generation, the UK Heat Networks Market Overview [47] does not explicitly mention nuclear heat as an option and neither does recent advice to Parliament [48, 49]. However, the Energy Technologies Institute (now part of the Energy Systems Catapult) has made a detailed case for SMRs to provide district heating [42]. We encourage further research into this area to help better understand the potential benefits and the technical challenges.

Overall, the potential for nuclear energy to contribute to economic reduction of carbon burdens is very great, and spans both the gigawatt-scale and SMR versions of LWRs, and the potential for a considerable programme of HTGRs. These possibilities combine to point to a "Flexible Nuclear" approach, within a grid comprising both VRE and nuclear, as a potential route to achieving net zero.

## 4.2 An Economic, Low-carbon Solution

In Sections 2.4 and 3.1 the issue was identified of the increases in LCOE of various supporting power sources needed for when the VRE is not available. Many of these power sources are expensive, or limited in their availability, or have constraints on low-capacity operation. In all cases the effect of the fixed costs of the plants would cause a sharp rise in electricity costs if required to operate at low capacity factors. This would for example prevent nuclear from being competitive when used to load follow for capacity factors much below 70%, as can be seen in Figure 7. We have shown that in the current DESNZ scenarios with very high capacities of VRE, the use of unabated natural gas with CCGT or rapid response gas turbines would be expensive and difficult to provide sufficient capacity. Failure to provide this capacity would mean more investment would be required in natural gas with CCS, hydrogen power and storage with the consequential transfer of the lower capacity factor and increased costs per unit of electricity delivered.

In 2023 the Royal Society looked at large scale electricity storage as a way of accommodating the variability of wind and solar power at high fractions of variable renewables [30, 31]. Some of these have aspects in common with the approach in this report. This report agrees with the conclusion from the Royal Society's work that using nuclear power as a baseload electricity supplier is unhelpful to a grid dominated by VRE, and that flexible dispatchable power is the best solution. However, unlike the Royal Society, we do not conclude that a significant role for natural gas (with or without CCS) is necessary. The use of large-scale electrical storage is also favoured in the most recent report of the Energy Systems Catapult [45].

The Energy Systems Catapult report also agrees with the Royal Society that both nuclear cogeneration and the use of thermal energy storage are useful, but we go further in focusing the nuclear applications on cogeneration applied to hydrogen production and related low-carbon use of heat and electricity. This frees nuclear to be diverted to supporting the grid when needed, thus bringing nuclear and VRE elements together as an entity. This is particularly true in the treatment of the potential role of HTGR reactors, which in the work by the Royal Society are assumed not to be available on a timescale to aid meeting net zero by 2050. However, much of the analysis is relevant to the scenarios the Dalton Nuclear Institute has examined, and comparisons between the findings would take a role in the work needed to further develop our thesis and to further underpin the central proposal for VRE and nuclear acting together.

It is clear from Figures 4 (page 19) and 7 (page 22) that an overall solution which combines nuclear energy with VRE could provide a very low carbon solution to the UK's electricity (and potentially much of its energy) needs. However, as already described, this would be made very difficult by the inflexible nature of traditional nuclear electricity generation. This problem can be avoided by any approach which allows the reactor to run at its highest power and availability levels, while making economic use of the energy produced, either as heat or electricity.

Building a substantial capacity to produce nuclear hydrogen would enable part or all of that capacity to be diverted to support the grid with electricity generation when VRE output is low. This is "spinning capacity" and would mean that electricity can be quickly and easily diverted for grid support, at the expense of some hydrogen production. Reducing nuclear power for hydrogen production by – for instance – 50% would approximately double the unit cost of the hydrogen, although the fraction of the power that would need to be diverted on average over a year would be expected to be much less than 50%. It is also important to note that any diversion would occur at a time of high electricity demand and therefore higher electricity prices, so the overall economic impact on hydrogen costs would be cushioned by electricity revenues. The impact of the costs on the cogeneration activities is also small because it is taken in a region of the cost-capacity factor curve that is quite flat. This avoids the economically disadvantageous situation of nuclear plants sitting idle when VRE output is high. Dedicated peaking plants inevitably operate in a region of the cost-capacity curve that is very steep. This can be seen in Figure 7, by comparing the proposal to use gas generation in a peaking role with capacity factors as low as 1%, and to use nuclear generation with capacity factors around 90%.

***Recommendation Seven***

***Government assessments of the impact of new nuclear capacity should recognise and incorporate cogeneration applications (including hydrogen production). These applications ensure high capacity factors can be achieved to keep costs low and provide grid support when renewable output is low. Where appropriate, the same reasoning should be applied by the operators of existing nuclear plants.***

As mentioned previously, this approach could also make use of excess VRE generation when VRE supply exceeds demand; in effect the excess electricity of both VRE and nuclear are used to produce hydrogen by high-temperature electrolysis. This would reduce the need to curtail VRE output, which was identified as one of the two weaknesses of VRE generation. This cogeneration effort would therefore resolve two of the serious operational problems associated with VRE and nuclear energy which were identified in Sections 3.1 and 3.2. Such a setup provides a firm example of how nuclear and renewables are complementary in pursuit of net zero.

***Recommendation Eight***

***Government and industry should aim to reduce the need for curtailment of renewable electricity by using cogenerated nuclear heat to power high-temperature electrolysis hydrogen production, in addition to short-term storage.***

## 4.3 A Flexible Nuclear Scenario

A "Flexible Nuclear" scenario, based on the use of nuclear cogeneration and AMR thermal storage technology is presented in Appendix 3. The calculations are tentative estimations using hydrogen production as the main cogeneration application, but with plenty of scope for other associated uses of nuclear heat – particularly waste heat. It is stressed that this is an illustrative scenario, not a projection. Determining the extent to which this can be achieved will require further investigation of the full potential of cogeneration, the costs and logistics of implementing such a scenario, and the details of how the complex interaction between reactor operation, heat storage, cogeneration activities and grid support can be managed. We present the scenario here to illustrate a potential future energy system which shows great promise in helping achieve net zero, whilst maximising the energy potential of both VRE and nuclear, and thus helping to keep system costs low. The main differences from the original DESNZ High Electrification scenario are:

- No use of natural gas, with or without CCS, beyond 2040 and no future construction of natural gas power stations.
- The capacity factors of hydrogen power generation and BECCS are increased to reduce their costs and to provide power at times of high demand in the winter. The increased BECCS capacity factor also delivers negative emissions.
- The estimated total electricity cost per year for the Flexible Nuclear scenario is £77 billion, compared to £91 billion for the High Electrification scenario (Tables 4 and 6 respectively) – a potential saving of up to £14 billion per year, depending on the extent of nuclear cogeneration delivered.

Whilst the estimated cost saving is based on full implementation of the Flexible Nuclear Scenario, which would be a massive undertaking, we feel the scale of the illustrative cost benefit makes further research into this approach an imperative. An even more ambitious and potentially even more favourable economic case can be generated using AMR technologies such as HTGRs, which can produce hydrogen more efficiently from a combination of high temperature heat and electricity in more effective hydrogen-production technologies. The use of the various technologies to produce hydrogen, synfuels, syngas and ammonia is discussed in Appendix 6. The possibility of using excess heat from nuclear plants to contribute to direct air capture of $CO_2$ and desalination, or for domestic and business heating is also discussed.

Figures 11 and 12 (page 36) show the evolution of the capacities and supply for this Flexible Nuclear example. It is important to note that the costs of this scenario are lower than the High Electrification scenario because even though it features high capacities at low capacity factors, the cogeneration by both types of nuclear means that the nuclear plants are not idling when not delivering electricity. Use of natural gas is phased out completely by 2040 and much reduced for 2030. The share of nuclear generation, to go directly onto the grid has gone down and is replaced largely by hydrogen generation. All the non-VRE generation is now flexible and there is the ability to supply additional power over a longer period, of the order of 2-3 weeks, when demand is high but VREs are not available.

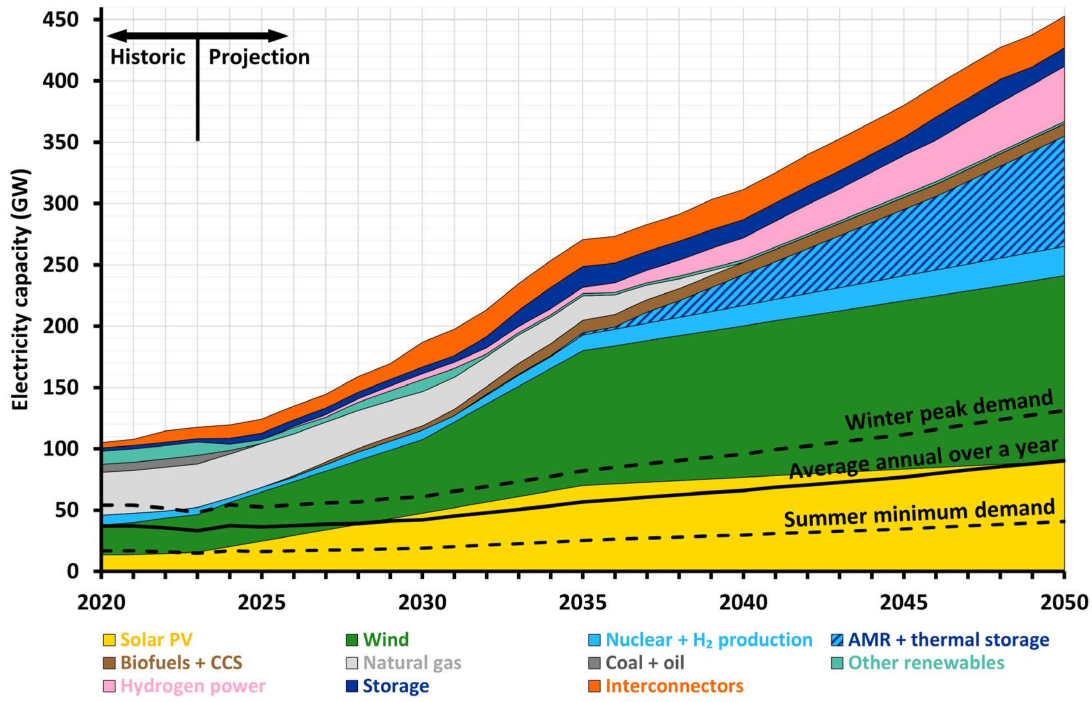



**Figure 11. Makeup of electricity capacity for the proposed Flexible Nuclear scenario – a modification of the DESNZ High Electrification scenario case eliminating natural gas and adding nuclear capacity with cogeneration and additional use of hydrogen.**

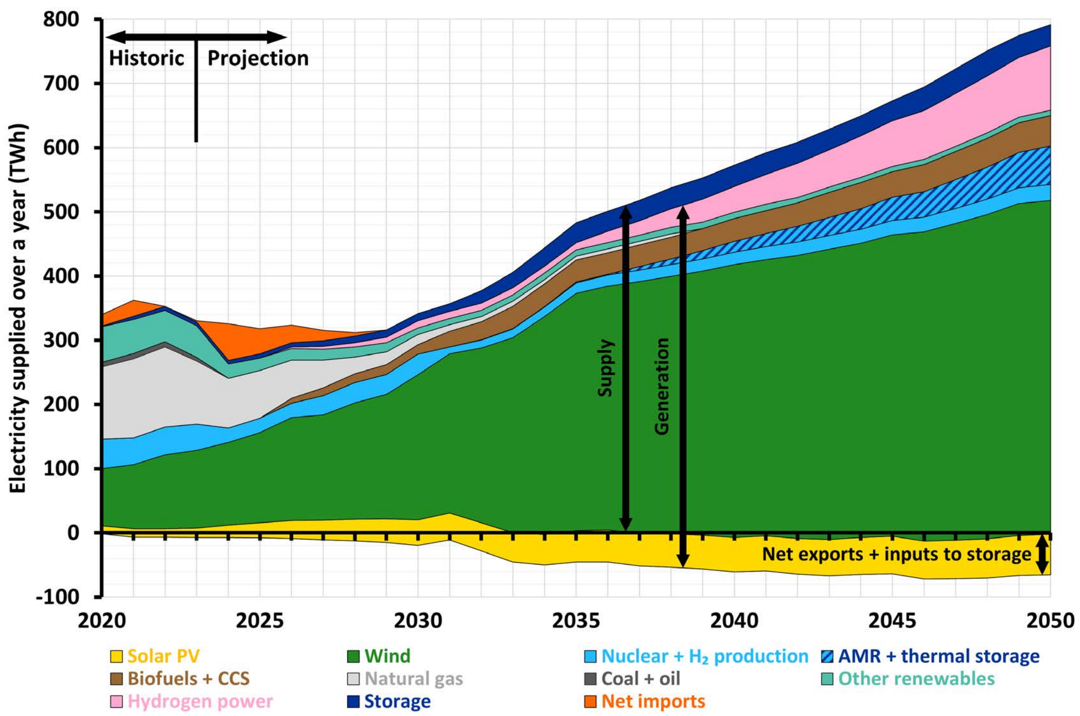



**Figure 12. Makeup of electricity supply for the proposed Flexible Nuclear scenario – a modification of the DESNZ High Electrification scenario case eliminating natural gas and adding nuclear capacity with cogeneration and additional use of hydrogen.**

Suffice here to say that, given the economics that HTGRs and their attendant technologies are expected to achieve, hydrogen generation could become a highly relevant energy source, both as an intermediate and for direct use. DESNZ is clearly convinced of the importance of AMR development to the extent of funding the building of an HTGR demonstration reactor to commence operation in the early 2030s [7].

Another very clear aid to nuclear flexibility enabled by HTGRs is the storage of energy in the form of heat. This can be combined with the provision of a generating capacity larger than that appropriate for the thermal rating of the reactor. This could enable the reactor complex to deliver between say, 0% and 300% of the electrical capacity of the reactor alone, varying over a period of many hours. Using thermal storage to achieve greater nuclear flexibility is discussed in detail in Appendix 7. With the combination of the potential for heat storage, large-scale nuclear cogeneration, low-cost hydrogen production and intelligent utilisation of VRE electricity, a cost-effective, reliable and flexible solution to the nation's energy demands should be attainable.

Appendices 2 and 3 allow a comparison between the DESNZ High Electrification scenario and the proposed Flexible Nuclear scenario. The nuclear capacity is grouped as two types:

1. The 24 GWe LWR capacity currently planned to be built as a combination of GW-sized plants and one or more fleets of SMRs, would have their focus on hydrogen production (there will certainly be a wider range of applications, but for simplicity only hydrogen production has been considered). Power can be switched to grid support for short or long periods, at low cost. The fraction of power supporting the grid decreases to around 12% by 2050, but in terms of time spent in support of the grid at less than the full capacity this will be much larger.
2. A very substantial capacity of AMR generation. The overall 90 GWe nuclear capacity assumed is based on a scenario where HTGRs with a thermal power around 60 GWth (the electrical power without storage would be ~30 GWe) are used to feed a high temperature heat store that can be used for both electricity generation and industrial uses of heat. The size of this store will need to be optimised but it would need to have a minimum capacity of several hours at the full power rating and, ideally, longer. This arrangement would be used for the shorter-term support of the grid and particularly when both solar and wind power are not available. Only around 7.6% of the of the available nuclear generation goes directly to the grid and the balance would be used for industrial applications including high efficiency hydrogen production.

The high flexibility in the thermal storage solution also allows the use of otherwise curtailed solar and wind generation, which has an additional beneficial effect of reducing the costs and emissions from renewable energy. The results of this scenario are summarised alongside those from the DESNZ High Electrification scenario in Table 3, which also appear in Table 11 in Appendix 6.

**Table 3. A comparison of the impact of the DESNZ High Electrification and the Flexible Nuclear scenarios in 2050, on costs and $CO_2$ equivalent emissions.**

| | DESNZ High Electrification scenario (Appendix 2) | Proposed Flexible Nuclear scenario (Appendix 3) |
|---|---|---|
| Cost of delivering ~840 TWh of power to the grid (£bn) | 92 | 77 |
| Averaged levelised cost of power (£/MWh) | 105 | 90 |
| Estimated emissions on a life cycle basis ($MtCO_2eq/yr$) | 75<br>(-11.4 from BECCS) | 15.5<br>(-28 from BECCS) |
| Nuclear electricity for cogeneration (TWh) | ~20 | ~400 |
| Nuclear heat for cogeneration (TWh) | ~60 | ~1000 |
| Nuclear waste heat some of which could be used (TWh) | ~500-700 | ~1250 |
| Amount of nuclear hydrogen that could be generated (Mt/yr) | ~15 | ~300<br>(~6 Mt/yr used for generation) |
| Emissions from hydrogen production ($tCO_2/tH_2$) | ~<1 for nuclear<br>~ 6 for steam reforming + CCS | ~<1 |

The cost of delivering the total electricity, the levelised cost, and the estimated emissions are all significantly reduced in the Flexible Nuclear scenario – by around 15% in terms of cost and around 79% in terms of $CO_2$ emissions.

Understandably, while the HTGR demonstration reactor is included in DESNZ's current future scenarios, the campaigns of HTGR reactor building and their possible roles are currently not covered. This has been rectified in this study, which examines these roles, and finds that an HTGR fleet combined with cogeneration and hydrogen generation can markedly improve progress to net zero and its economics, as noted above.

## 4.4 Implementing the Solution

The Flexible Nuclear solution presented here to the challenge of net zero involves use of the current suggested expansion of nuclear electricity and a substantial fleet of HTGRs. Hydrogen production and heat storage from these plants would accommodate the variations in VRE output and grid demand and ensure high capacity factors to achieve better economics.

The technologies and techniques used are very likely to be available as required, so the viability of the overall approach solution will depend on the "flexible nuclear" contribution to an overall system which is economic and can provide the answer to the initial challenge posed by this study in Section 1: "Ensure a low-carbon electricity supply to consumers, relying on a robust grid which is resilient to variations in electricity demand and generation (especially weather for renewables)".

The viability of the scenario presented here depends to a large degree on the successful economic development and installation of a fleet of HTGR reactors. The number of reactors this would entail would obviously vary depending on the rating of the reactor in question, but to fully realise the ambitious scenario would equate to 100 GTHTR300* reactors. This will involve not only the successful demonstrator, but the development of economic fleet build, a robust supply chain (including fuel), and all necessary accompanying conversion technologies for the use of heat – particularly for the economic generation of hydrogen. Whilst the building of around 100 new advanced reactors by 2050 would be a massive undertaking, it is important to recognise that even a partial implementation of this scenario would deliver a substantial element of the overall package of benefits.

It is, of course, worth emphasising that no solution to the requirement of "low-carbon energy" can succeed in the absence of a "robust grid". Grid costs are not explicitly addressed in this work, but all the solutions depend on the grid being developed to support the variety of electricity transfer elements discussed – recognising the overall increase in grid requirements from the increased generation and its variability.

Synergy is an important reality which must be faced if an effective low-carbon energy future is to be achieved. As electricity becomes more and more the responsibility of VRE generators, lots of additional baseload nuclear generation may not just be unhelpful, but actively detrimental to the entire system as it presents a dilemma between idling thermal generators or large-scale VRE curtailment.

***Recommendation Nine***

***Nuclear energy should not be restricted to delivering only baseload electricity generation. The possibility of locating new nuclear build on existing or purpose-built industrial parks that would maximise the opportunity for cogeneration must be explored.***

One aim of this paper is to demonstrate that intelligent planning is essential, with attention paid to ensuring that enough cogeneration is made available to prevent such high levels of curtailment and to successfully manage the intermittency of VRE generation. Energy decisions should not be made in isolation, but with an appreciation of how each technology fits in the whole system.

***Recommendation Ten***

***Government planning for future nuclear deployment should envisage an integrated system where nuclear and variable renewables work in harmony through cogeneration and energy storage, and such planning around energy (not just electricity) infrastructure delivery should be fully co-ordinated to best ensure the UK has a functional whole system.***

* *The **GTHTR300** is a 600 MWth prismatic reactor design from Japan, and one of the more well-developed HTGR designs.*

## 4.5 **Summary of Section 4**

- The proposed Flexible Nuclear scenario uses nuclear energy for both grid support and cogeneration applications, with most output directed at cogeneration. This is instead of building dedicated gas generation intended for use at very low capacity factor.
- Analysis in Appendix 3 suggests that this Flexible Nuclear scenario could save around £14 billion per year compared to the DESNZ High Electrification scenario analysed in Appendix 2. Full implementation of this scenario would require the delivery of a large fleet of reactors, yet substantial savings could still be made even if more modest progress was actually achieved.
- With a large nuclear capacity and a focus on cogeneration activities, nuclear energy could be diverted to provide electrical power to the grid when needed (i.e. when VRE output is low). This cogeneration setup would make nuclear energy flexible in a way it has not been previously.
- Nuclear can be made even more flexible with the addition of molten salt thermal storage – a cheaper and more scalable alternative to batteries or pumped energy storage.
- Production of hydrogen has been assumed as the main cogeneration application for this analysis, but other applications for nuclear heat are available.
- Hydrogen from electrolysis is most efficiently delivered at high temperature, with SOEC technology the highest TRL available. Both high- and low-grade heat are of value for this application.
- The need for VRE curtailment can be prevented if excess electricity is used along with nuclear heat to produce hydrogen.
- In this scenario, wind and solar provide up to 68% of the total electricity supply in 2050.

# 5 Conclusions

1. If net zero is to be achieved, high capacities of low cost solar and wind electricity generation are needed. Because wind and solar power are variable and unpredictable, a standby generation of dispatchable equivalent capacity is needed for when their output is low to ensure a reliable electricity supply. When VRE output is higher than demand it needs to be stored, exported or used (e.g. for making hydrogen) rather than curtailed.
2. The current DESNZ High Electrification Scenario assumes high capacities of unabated gas generation filling this role and operating only for the limited periods when VRE output is low.
3. This supporting gas generation has high lifecycle costs when used at low capacity factors and produces expensive electricity (and $CO_2$) as a result.
4. We propose a Flexible Nuclear alternative, relying on nuclear cogeneration to provide electricity when wind and solar power are not available, and nuclear-generated electricity and heat for other low-carbon industrial applications when VRE electricity is plentiful. An example industrial application is nuclear hydrogen production, which has much lower carbon emissions than steam reforming of natural gas, even with CCS.
5. Nuclear cogeneration with hydrogen production and the potential to deliver electricity to the grid when needed allows capacity factors to remain high for the capital-intensive nuclear reactors and the hydrogen production plants. A high capacity factor is essential for nuclear energy to be economic.
6. The low-carbon hydrogen can be used in supporting electricity generation in the winter when demand is high.
7. This concept is not limited to hydrogen production – it can also be applied to other cogeneration applications such as production of synfuels and direct air capture of $CO_2$.
8. Nuclear cogeneration also allows the use of excess renewable electricity that would otherwise be curtailed to be used effectively in hydrogen production.
9. The outcome of the proposed approach is an overall system which achieves greater reduction of $CO_2$ emissions, at lower cost compared to the existing High Electrification Scenario (up to £14 billion per year cheaper, depending on how many reactors can be delivered by 2050). This partnership between renewables and nuclear energy solves an otherwise very difficult problem.

## 5.1 **Potential Next Steps**

Beyond specific policy recommendations, we consider that the following steps would be appropriate next actions for government, industry and academia, in relation to the work outlined in this paper.

- Further research and development into thermal energy storage technology is necessary, as the technology's engineering feasibility is central to achieving the potential economic benefits of the Flexible Nuclear approach.
- Further research into the practical constraints around delivery of the outlined scale and scope of both renewable and nuclear technologies, on the timeframes envisaged here, is also needed. This would include consideration of skills (including training capability), supply chain issues, planning, community engagement, finance, etc.
- Given the anticipated challenges in achieving full deployment of the nuclear capacity simulated in the Flexible Nuclear approach towards a high electrification future for the UK, analysis of different levels of partial Flexible Nuclear deployment would support its implementation.
- Holistic modelling of integrated energy systems with linkages between the generation, transmission and storage of electricity, heat and hydrogen would be insightful. An organisation such as the Energy Systems Catapult would be well-placed to carry out such work in collaboration with NNL and the Dalton Nuclear Institute.
- A specific example of such modelling would be an evaluation of the likely impact on the grid, and how this might compare with implications for the grid arising from other scenarios to reach net zero by 2050. This grid analysis should consider both technical and cost aspects and should look at the electricity grid, the existing gas grid, implications for hydrogen and any infrastructure needed to transmit heat from place to place in the quantities envisaged.
- As noted in Section 4.1.2, we would like to see additional research into the potential use of heat from future small reactors (SMRs and AMRs) for district heating.
- Consideration of potential changes to markets (and how to achieve them) which might be needed to accommodate a future energy landscape of the kind outlined here would also be interesting. Currently, the market is primarily focused on providing electricity to domestic and industrial consumers. In the future, effective mechanisms to encourage and value the generation, trading and inter-conversion of electricity, heat and hydrogen will be needed.

# Recommendations

### *Recommendation One*

*All energy infrastructure becomes less economically effective per unit of output as the capacity factor reduces. Government decision-making on the future energy mix should consider the capacity factors of new and existing infrastructure, and where these are low, seek alternatives which are potentially more cost effective.*

### *Recommendation Two*

*Since variable renewable energy generation can experience long periods with little to no output and storage options are limited in scale, Government should ensure that the delivery of low-carbon, cost-effective, dispatchable electricity is prioritised to best support an effective overall system.*

### *Recommendation Three*

*As the proportion of variable renewable energy on a network increases, so will the amount of curtailment unless close attention is paid to the whole system. Government should ensure that the inefficiency of curtailment is recognised and that it is minimised as far as possible, for instance by ensuring that large-scale solar power has associated electricity storage.*

### *Recommendation Four*

*Using reactors with thermal storage can potentially offer a cost-effective contribution to solving the problem of nuclear inflexibility. Government should prioritise research to enable an in-depth investigation of the opportunity.*

### *Recommendation Five*

*Government, working through Great British Nuclear, should strive to improve the economics of nuclear energy by encouraging fleet build of nuclear plants, with minimal delays, and which are then operated at a high capacity factor.*

### *Recommendation Six*

*Government's future energy strategies should include full appreciation of effects at the whole system level, comprising generation, transmission, and storage, which must all be developed in parallel.*

### *Recommendation Seven*

*Government assessments of the impact of new nuclear capacity should recognise and incorporate cogeneration applications (including hydrogen production). These applications ensure high capacity factors can be achieved to keep costs low and provide grid support when renewable output is low. Where appropriate, the same reasoning should be applied by the operators of existing nuclear plants.*

### *Recommendation Eight*

*Government and industry should aim to reduce the need for curtailment of renewable electricity by using cogenerated nuclear heat to power high-temperature electrolysis hydrogen production, in addition to short-term storage.*

### *Recommendation Nine*

*Nuclear energy should not be restricted to delivering only baseload electricity generation. The possibility of locating new nuclear build on existing or purpose-built industrial parks that would maximise the opportunity for cogeneration must be explored.*

### *Recommendation Ten*

*Government planning for future nuclear deployment should envisage an integrated system where nuclear and variable renewables work in harmony through cogeneration and energy storage, and such planning around energy (not just electricity) infrastructure delivery should be fully co-ordinated to best ensure the UK has a functional whole system.*

# Appendix 1: VRE in the DESNZ Base Case

The DESNZ Base Case is a scenario with limited expansion of projected UK electricity capacity to 2040. It is based mainly on existing technologies and includes a substantial contribution from unabated natural gas. This scenario could be considered as what is likely to happen with a lack of commitment to and investment in developing new technologies.

Figure 13 shows the makeup of electrical power capacity for the DESNZ Base Case scenario for the period 2020-2040 [3].

The Base Case has a strong growth in variable renewable capacity but a limited growth in electricity demand and limited expansion of other low-carbon generation (i.e. nuclear and gas with CCS). Some assumptions were made in the projections for winter maximum and minimum demand. In the projections, renewable energy was not analysed in detail, so assumptions were made on the share of wind, solar and non-variable renewables, mainly hydropower and biofuel generation. These assumptions do not affect the conclusions of our work.

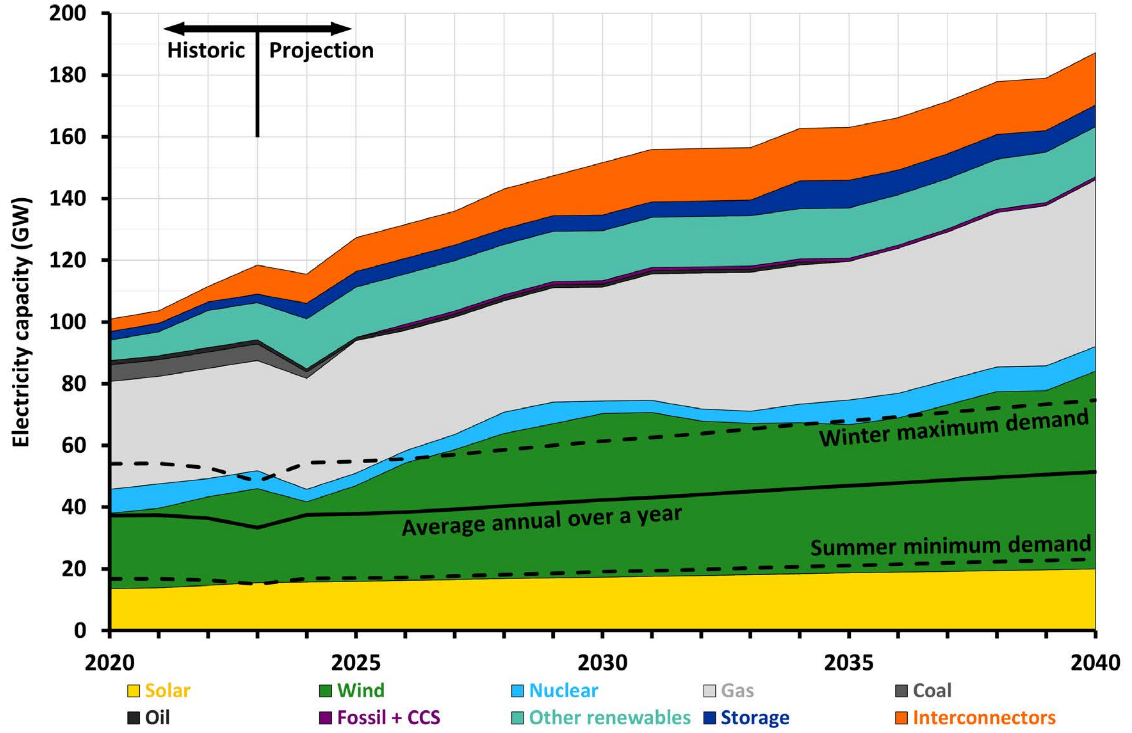



**Figure 13. Historic and Base Case projections for electricity capacity to 2040 with average demand and estimated maximum and minimum demand levels [3].**

Figure 14 shows the projected annual generation on the same basis as Figure 13. The baseline for energy supplied was offset by a negative contribution from the input of energy to storage, which is mainly pumped hydro. Interconnectors with the island of Ireland and mainland Europe have a net positive (i.e. import) contribution for the whole period.

The main points to note from Figures 13 and 14 are:

- There is a predicted increase in electricity generation installed capacity from 2024, dominated by offshore wind with continued growth of unabated natural gas capacity and some nuclear.
- The generation projections show the expected large growth of wind contribution (associated with the expansion of capacity), limited new nuclear, but contraction of natural gas generation – despite expansion of the installed capacity of gas. This is because of a sharp reduction in gas capacity factor, which is a direct consequence of the increasing proportion of wind power in the generation mix.
- Some of the generation when wind power is not available is supplied by interconnectors, but the time of peak demand is not much different in the UK to that of the island of Ireland and Western European countries, so in the Base Case scenario the burden of filling-in missing wind generation currently rests with natural gas plants.

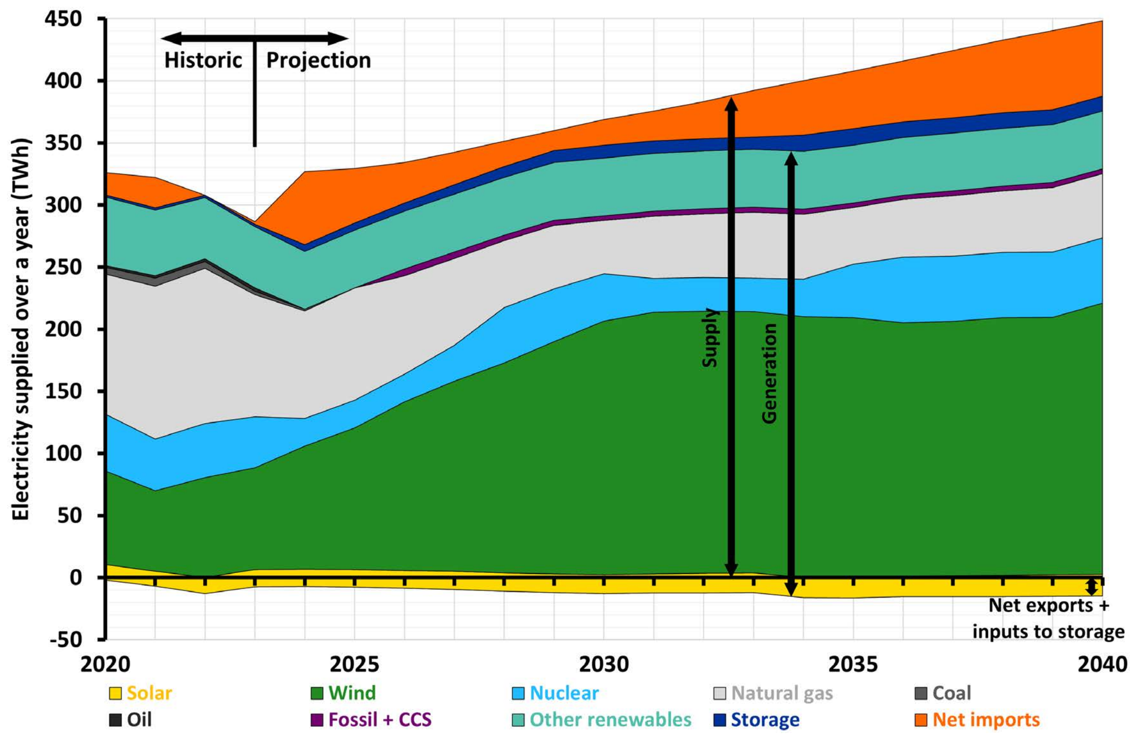



**Figure 14. Historic and Base Case projections for annual electricity generation to 2040 [3]. It is incidental that the contribution from solar generation is similar to the input to storage.**

# Appendix 2: VRE in the DESNZ High Electrification Scenario

This Appendix looks at the High Electrification scenario issued following the "Powering Up Britain" report [12]. This tries to provide a solution to reaching net zero by 2050 and includes a number of new low-carbon technologies that are not yet part of the current electricity landscape.

Figures 15 and 16 (page 46) show the makeup of the capacity and generation for the high electricity demand scenario.

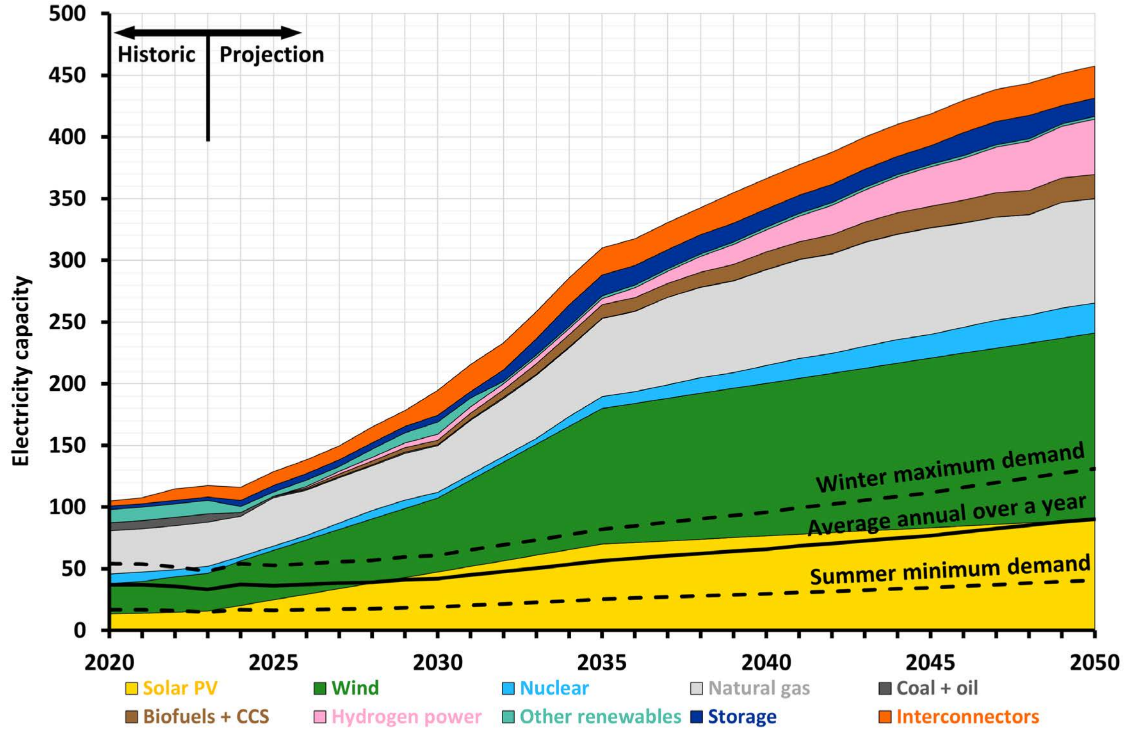



**Figure 15. Makeup of electricity capacity for the DESNZ High Electrification scenario.**

The makeup of electricity generation for the High Electrification scenario is shown in Figure 16. Both the high and low scenarios predict that the UK would be a net exporter of electricity from around 2028, so the net exported electricity is added to the input to storage as a negative contribution. It is striking that the generation is dominated by the nuclear, wind and solar contributions, while unabated gas and the expensive new technologies make little contribution. This implies a significant level of wind curtailment, which can be seen by comparing the projected wind achievable capacity factors with the values that can be calculated from the scenario data. There is also an implied reduction in the nuclear capacity factor. See Table 1 in the body of this report.

In these scenarios CCS is a significant component from around 2025, which will be difficult to achieve as demonstration projects are only just starting in the UK. CCS is important as it includes both abated natural gas and biofuels, and biofuels with CCS offer the only negative contributions to greenhouse gas emissions in the scenarios. Using hydrogen for CCGT generation is also included starting from round 2025. The source of the hydrogen would be steam or oxygen reforming of methane from natural gas with CCS. Two large projects are preparing to provide the hydrogen and trial the CCS processes [50, 51].

The mismatches between electricity supply and demand are rectified by the five dispatchable sources of power: Nuclear, CCS (gas fired and biofuels), hydrogen, unabated natural gas, and electricity from storage. The dispatchable power sources show reductions in capacity factor to accommodate the fluctuations from the very large fractions of VRE.

The main points to note here are:

- Nuclear is usually run as a baseload electricity generator, as there are restrictions on power variation and capital costs dominate. In the DESNZ scenarios the nuclear contribution is assumed to load follow at the required profile, whether this is possible depends on the required profile and the reactor type, but even if it is possible, this increases costs. EDF's experience with load following could be valuable in assessing this.
- As the proportion of CCS capacity grows there is a significant reduction in capacity factor with increasing VRE fraction.

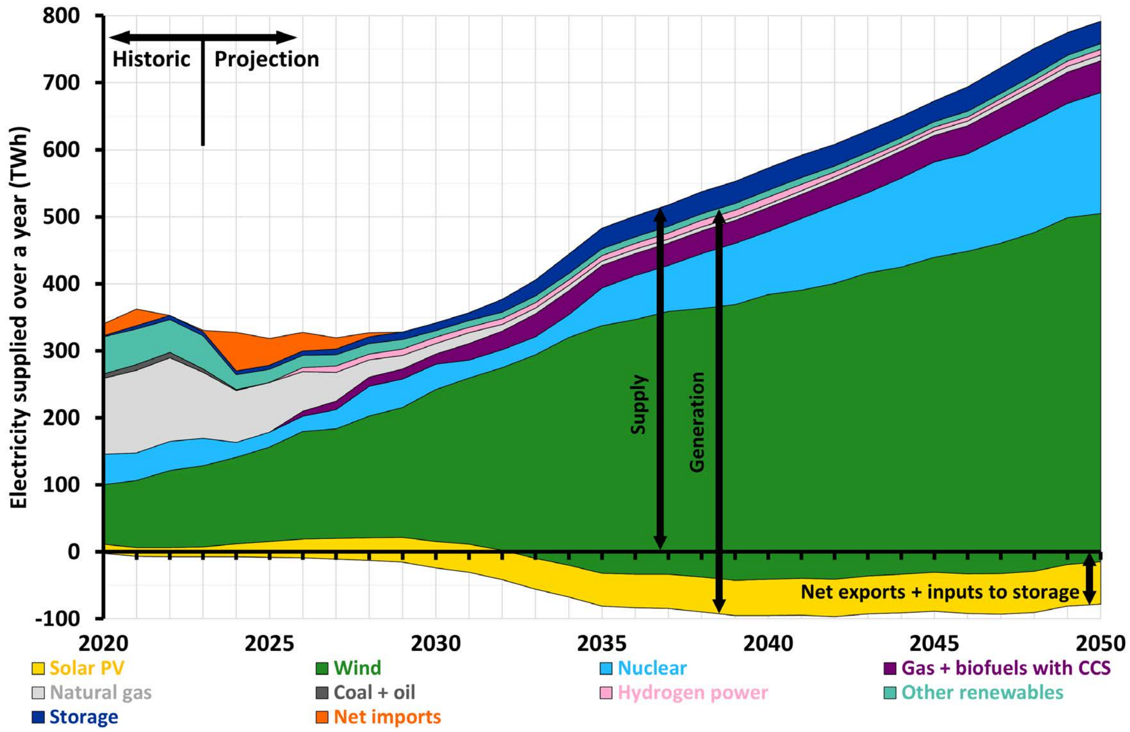



**Figure 16. Makeup of electricity supply for the DESNZ High Electrification scenario [3]. It is incidental that the contribution from solar generation is similar to the net exports plus input to storage.**

- The use of unabated gas power has both a large increase in capacity and a greatly reduced capacity factor, which will have major cost implications for the viability of this option.
- The use of pumped hydro storage and battery storage have an important role to play on supporting VRE over short periods, but the capacity is insufficient to provide long-term support.

Calculating the cost of electricity from such scenarios is very difficult, because of the wide range of plants involved, their different ages, and the need to account for their history in calculating the LCOE. Because of this, costs were calculated based on a representative design for each class of generation, considering changes in costs with time. Table 4 (page 48) shows these costs for the High Electrification scenario. Importantly, note that in 2050, this scenario predicts unabated natural gas generation contributes 11% of the total cost of generation to deliver 1% of the electricity.

The only nuclear cost calculation available from DESNZ is from 2016 and is based on the Hinkley Point C case. It is anticipated that future nuclear new build will have substantially lower costs and the costs used from 2030 onwards reflect this [26]. There were no available DESNZ costs for batteries, so estimates for costs and anticipated future cost reductions were based on utility scale Li-ion batteries from recent publications [52–54].

The calculations are reassuring, as the average LCOE decreases with new technology development. However, there is an issue with "peaking" generation (i.e. the dispatchable generation needed to supply electricity when the VRE is not available but demand is high). This falls heavily on unabated natural gas as the generator of last resort – with high variable costs and with the potential burden of future carbon levies, which would inevitably be passed on to consumers if a company were ever able to make the business case work with such unattractive numbers. An increase in current gas capacity is required, but the capacity factor would be very small. This situation is unlikely to be viable as it would involve developers needing to build plants that comprise almost a quarter of the total UK capacity by 2050, but only deliver a 1% share of the actual generation, with an effective cost >£1000/MWh. The total cost of the unabated gas generation amounts to ~£10 billion – over 10% of the total electricity costs.

Estimating $CO_2$ equivalent emissions is difficult but it is worth making some estimates as these are useful in making decisions on the best choices of technology to reach not only net zero but also to minimise the impact of emissions during the transition.

Lack of full information on the capacity and generation of solar PV and wind energy meant assumptions had to be made. Some assumptions had to be made on the capacity factors of solar and wind. A small degree of curtailment was allocated to solar (from 11% to 8%) and larger amounts to wind to match the overall levels of renewable generation. These are reflected in the estimates of $CO_2$ equivalent emissions in Table 5 (page 49).

**Table 4. Estimated costs of electricity for the High Electrification scenario mostly using BEIS and DESNZ cost data (2023 money) [17, 18, 24].**

| | % of Generation | | | | % of Total LCOE | | | | LCOE (£/MWh) | | | | Cost (£bn/yr) | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2030 | 2040 | 2050 | 2025 | 2030 | 2040 | 2050 | 2025 | 2030 | 2040 | 2050 | 2025 | 2030 | 2040 | 2050 |
| Solar PV | 8.3 | 11 | 8.1 | 10 | 3.3 | 4.8 | 3.1 | 2.9 | 45 | 45 | 42 | 42 | 1.06 | 1.77 | 2.27 | 2.66 |
| Onshore wind | 22 | 24 | 21 | 15 | 13 | 15 | 12 | 8.3 | 66 | 56 | 60 | 59 | 4.26 | 5.42 | 8.24 | 7.52 |
| Offshore wind | 26 | 35 | 43 | 45 | 19 | 25 | 33 | 32 | 80 | 70 | 84 | 76 | 6.06 | 9.04 | 24.26 | 29.34 |
| Hydro | 1.4 | 1 | 0.6 | 0.5 | 1.7 | 1.4 | 0.7 | 0.6 | 133 | 133 | 133 | 133 | 0.53 | 0.53 | 0.53 | 0.53 |
| Bioenergy | 5.5 | 1.8 | 0.9 | 0.5 | 5.9 | 13 | 3.1 | 2.4 | 120 | 476 | 372 | 495 | 1.87 | 4.76 | 2.23 | 2.14 |
| Bioenergy + CCS | 0 | 0.3 | 1.5 | 2.7 | - | 1.1 | 6.7 | 12 | - | 338 | 459 | 470 | - | 0.42 | 4.78 | 11.15 |
| Gas + CCS | 0 | 3.8 | 3.8 | 2.7 | - | 4.5 | 6.7 | 4.6 | - | 121 | 164 | 175 | - | 1.64 | 4.16 | 4.15 |
| Nuclear | 7.8 | 9.7 | 14 | 21 | 11 | 11 | 16 | 16 | 162 | 110 | 121 | 80 | 3.61 | 4.19 | 11.42 | 14.41 |
| Hydrogen | 0 | 2.7 | 1.6 | 1 | - | 4.6 | 4.2 | 6.2 | - | 181 | 281 | 648 | - | 1.71 | 2.97 | 5.66 |
| Unabated gas | 26 | 5.3 | 0.8 | 1 | 40 | 16 | 11 | 11 | 172 | 373 | 1524 | 1139 | 12.79 | 5.82 | 8.12 | 9.83 |
| Pumped hydro | 1.4 | 1.1 | 0.6 | 0.5 | 2.1 | 2.3 | 1.2 | 0.9 | 207 | 207 | 207 | 207 | 0.85 | 0.85 | 0.85 | 0.85 |
| Battery storage | 0.8 | 1.8 | 4.3 | 3.4 | 2.4 | 1.9 | 4.2 | 3.3 | 352 | 95 | 103 | 103 | 0.76 | 0.71 | 3.00 | 3.01 |
| | | | | | | | | | Average LCOE (£/MWh) | | | | Total Cost (£bn/yr) | | | |
| | | | | | | | | | 111 | 100 | 109 | 105 | 31.79 | 36.86 | 72.83 | 91.25 |

**Table 5. Representative estimates of the $CO_2$ equivalent emission per MWh of electricity generation for the main contributions to generation in the DESNZ High Electrification scenario. The emission rates change with years mainly from the capacity factors of the generation technologies. Hydrogen assumed to be produced using methane reformation with CCS.**

| | Fixed $kgCO_2eq/MWh$ | Variable $kgCO_2eq/MWh$ | 2025 total $kgCO_2eq/MWh$ | 2030 total $kgCO_2eq/MWh$ | 2040 total $kgCO_2eq/MWh$ | 2050 total $kgCO_2eq/MWh$ |
|---|---|---|---|---|---|---|
| Solar PV | 5.5 | small | 50 | 58 | 69 | 69 |
| Onshore wind | 13.5 | small | 45 | 39 | 42 | 41 |
| Offshore wind | 6.1 | small | 16 | 14 | 14 | 14 |
| Hydro | 2.25 | small | 8 | 8 | 8 | 8 |
| Bioenergy | 42 | 0.69 | 50 | 309 | 233 | 324 |
| Bioenergy + CCS | 58.8 | -690 | 0 | -569 | -486 | -478 |
| Gas + CCS | 56 | 72.95 | 0 | 189 | 268 | 275 |
| Nuclear | 9.3 | small | 13 | 10 | 12 | 11 |
| Hydrogen | 46.5 | 206 | 0 | 255 | 255 | 2305 |
| Unabated gas | 46.5 | 387 | 602 | 1375 | 6312 | 4374 |
| Pumped hydro | 3.15 | small | 18 | 18 | 18 | 18 |
| Battery storage | 30 | small | 314 | 91 | 109 | 109 |

# Appendix 3: The "Flexible Nuclear" Alternative

This Appendix looks at the potential of using nuclear power to provide a cheaper solution to reaching net zero by 2050. This scenario eliminates the use of all fossil fuels by 2050 and tries to get the best out of VRE by eliminating curtailment and allowing them to reach the full potential of the resources and the target capacity factors. This is based on the DESNZ High Electrification scenario and uses the same installed capacities for solar, wind, bioenergy with CCS, interconnectors, hydro, pumped storage and batteries. The use of natural gas, both unmitigated and with CCS, is reduced and eliminated by 2035. The capacity factors of solar and wind are increased, reducing curtailment. This and the displaced gas are replaced by nuclear energy with more generation from hydrogen, which is itself produced by nuclear energy.

Three types of nuclear capacity are proposed:

- Gigawatt-scale plants based on Gen-III or Gen-III+ technology at not more than about 12 GWe in total.
- SMRs building up to ~12 GWe by 2050.
- A further 60 GWth of AMR capacity with associated thermal energy storage.

This would be a total effective nuclear capacity of around 115 GWe, if Sizewell B is still operating. 60 GWth of heat-focused AMR capacity would nominally produce 30 GWe, but with the addition of thermal storage and additional generating capacity, a peak electrical power output of 90 GWe can be achieved. The 24 GWe of SMRs and gigawatt-scale LWRs is already in the DESNZ recent civil nuclear roadmap [19], but the ability to meet a large expansion of AMR capacity relies on completion of the proposals coming out of the AMR RD&D programme [7]. This is clearly ambitious, but the purpose of the scenario is to highlight the benefits of grid flexibility from nuclear cogeneration. Partially implementing the scenario by utilising cogeneration in this way would still have considerable impact – how much would depend on the extent of the deployment.

The UK Hydrogen Strategy looks towards having 250-460 TWh [55, p. 9] or 75-140 Mt of hydrogen production per year by 2050. Producing this by Proton Exchange Membrane (PEM; see Appendix 6 for details) at 95% capacity factor would require an electrical capacity of 50-90 GWe [55]. If high quality heat is available, then SOEC hydrogen production would need 33-61 GWe capacity plus 8-17 GWth of nuclear heat.

The example chosen uses the currently proposed 24 GWe of PWR-based gigawatt and SMR stations for mainly hydrogen production and the equivalent of a capacity factor of 12% for grid support. In addition, there would be the equivalent capacity of 90 GWe of AMR capacity using thermal storage (three times the nominal reactor generating capacity). At the full 90 GWe capacity the grid support would be available for an equivalent capacity factor of 7.6%. The AMR system would use the equivalent of a 75% capacity factor with a mixture of heat and electricity for industrial use such as hydrogen production.

This would be supplemented with electricity from solar and wind during periods of high output (this would otherwise be curtailed), increasing the equivalent capacity factors and reducing costs. Nuclear hydrogen would also be used to provide both short-term rapid response grid support for frequency maintenance and to support long term annual variations in demand. To do this the capacity factor for this example is increased to 25%. The use of BECCS, which is a valuable source of dispatchable power as well as negative emissions, has an increased capacity factor of 70%.

Figures 11 and 12 in the main document show the evolution of the capacities and supply for this Flexible Nuclear scenario. It is important to note that the costs of this scenario are lower than the High Electrification scenario because even though it features high capacities at low capacity factors, the cogeneration by both types of nuclear means that the nuclear plants are not idling when not delivering electricity. Use of natural gas is phased out completely by 2040 and much reduced for 2030. The share of nuclear generation to go directly onto the gird has gone down and is replaced largely by hydrogen generation. All the non-VRE generation is now flexible and there is the ability to supply additional power over a longer period when demand is high but VREs are not available. Table 6 shows the equivalent data for the Flexible Nuclear scenario, which should be compared with the data for the DESNZ High Electrification scenario presented in Table 4 in Appendix 2. The key changes between the two tables are the data for gas, nuclear, AMR, and importantly the total cost which is £14 billion less per year in the Flexible Nuclear case. The costing model for cogeneration-enabled flexible nuclear is explained in Appendix 7.

**Table 6. Estimated costs of electricity for the Flexible Nuclear scenario mostly using BEIS and DESNZ cost data (2023 money) [17, 18, 24].**

| | % of Generation | | | | % of Total LCOE | | | | LCOE (£/MWh) | | | | Cost (£bn/yr) | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2030 | 2040 | 2050 | 2025 | 2030 | 2040 | 2050 | 2025 | 2030 | 2040 | 2050 | 2025 | 2030 | 2040 | 2050 |
| Solar PV | 8.3 | 11 | 8.5 | 7.4 | 3.3 | 4.1 | 2.9 | 2.5 | 45 | 39 | 31 | 31 | 1.06 | 1.53 | 1.65 | 1.94 |
| Onshore wind | 23 | 26 | 22 | 15 | 13 | 15 | 14 | 9.7 | 66 | 56 | 60 | 59 | 4.26 | 5.42 | 8.24 | 7.52 |
| Offshore wind | 26 | 35 | 45 | 46 | 19 | 21 | 33 | 33 | 80 | 61 | 66 | 66 | 6.06 | 7.84 | 18.96 | 25.80 |
| Hydro | 1.4 | 1.1 | 0.6 | 0.5 | 1.6 | 1.4 | 0.9 | 0.7 | 133 | 133 | 133 | 133 | 0.53 | 0.53 | 0.53 | 0.53 |
| Bioenergy | 5.4 | 2.7 | 0.9 | 0.5 | 5.8 | 13 | 3.9 | 2.8 | 120 | 476 | 372 | 495 | 1.87 | 4.76 | 2.23 | 2.14 |
| Bioenergy + CCS | 0 | 4 | 5.6 | 5.5 | - | 13 | 23 | 19 | - | 338 | 366 | 316 | - | 5.30 | 13.10 | 15.01 |
| Nuclear + $H_2$ production | 7.8 | 9.3 | 3.1 | 2.9 | 14 | 10 | 3.9 | 2.4 | 162 | 114 | 101 | 74 | 3.61 | 3.90 | 1.95 | 1.86 |
| AMR + thermal storage | 0 | 0 | 2.6 | 7 | - | - | 1.9 | 5.2 | - | - | 64 | 67 | - | - | 1.07 | 4.01 |
| Hydrogen | 0 | 3 | 6.3 | 12 | - | 5.1 | 10 | 19 | - | 171 | 165 | 148 | - | 1.90 | 5.91 | 14.76 |
| Unabated gas | 26 | 4.4 | 0 | 0 | 38 | 13 | 0 | 0 | 172 | 311 | - | - | 12.79 | 4.97 | - | - |
| Pumped hydro | 1.4 | 1.1 | 0.6 | 0.5 | 2.6 | 1.9 | 1.5 | 1 | 207 | 207 | 207 | 207 | 0.85 | 0.85 | 0.85 | 0.85 |
| Battery storage | 0.8 | 2 | 4.5 | 3.4 | 2.3 | 1.9 | 5.2 | 3.9 | 352 | 95 | 103 | 103 | 0.76 | 0.71 | 3.00 | 3.01 |
| | | | | | | | | | Average LCOE (£/MWh) | | | | Total Cost (£bn/yr) | | | |
| Flexible Nuclear scenario | | | | | | | | | 111 | 102 | 91 | 90 | 31.80 | 37.40 | 57.50 | 77.42 |
| DESNZ High Electrification scenario (Table 4) | | | | | | | | | 111 | 100 | 109 | 105 | 31.79 | 36.86 | 72.83 | 91.25 |

Table 7 shows estimates of the $CO_2$ equivalent emissions by generation method per MWh. As well as the addition of the AMR case, there are other changes in the emission rate due to the changes in the capacity factor in this Flexible Nuclear scenario compared to the DESNZ High Electrification case.

One of these is the assumption that otherwise curtailed solar and wind generation is used to make hydrogen in nuclear industrial parks. There is a reduction in most cases in later years.

**Table 7. Representative estimates of the $CO_2$ equivalent emission per MWh of electricity generation for the main contributions to generation in the Flexible Nuclear scenario. Hydrogen assumed to be produced using nuclear energy.**

| | Fixed $kgCO_2eq/MWh$ | Variable $kgCO_2eq/MWh$ | 2025 total $kgCO_2eq/MWh$ | 2030 total $kgCO_2eq/MWh$ | 2040 total $kgCO_2eq/MWh$ | 2050 total $kgCO_2eq/MWh$ |
|---|---|---|---|---|---|---|
| Solar PV | 5.5 | small | 50 | 58 | 69 | 69 |
| Onshore wind | 13.5 | small | 45 | 39 | 42 | 41 |
| Offshore wind | 6.1 | small | 16 | 14 | 14 | 14 |
| Hydro | 2.25 | small | 8 | 8 | 8 | 8 |
| Bioenergy | 42 | 0.69 | 50 | 309 | 233 | 324 |
| Bioenergy + CCS | 58.8 | -690 | 0 | -569 | -542 | -583 |
| Gas + CCS | 56 | 72.95 | 0 | 0 | 0 | 0 |
| Nuclear +$H_2$ | 9.3 | small | 13 | 10 | 10 | 10 |
| AMR + n. heat | 9 | small | 0 | 0 | 10 | 10 |
| Hydrogen | 46.5 | 41.85 | 0 | 225 | 225 | 225 |
| Unabated gas | 46.5 | 387 | 582 | 1096 | 0 | 0 |
| Pumped hydro | 3.15 | small | 18 | 18 | 18 | 18 |
| Battery storage | 30 | small | 314 | 91 | 109 | 109 |

# Appendix 4: Electricity Curtailment

Before looking at the interaction between different means of electricity production, it should be noted that since the growth of renewables in the UK, VRE (particularly wind power) has been curtailed to an increasing extent as the fraction of VRE in electricity generation increases. Curtailment of VRE can occur even with a low share of VRE in the energy mix through, for example, inadequate provision of distribution network capacity, conflict with other local energy production, or lack of energy storage; but these issues can be dealt with by careful planning and adequate investment in the distribution networks.

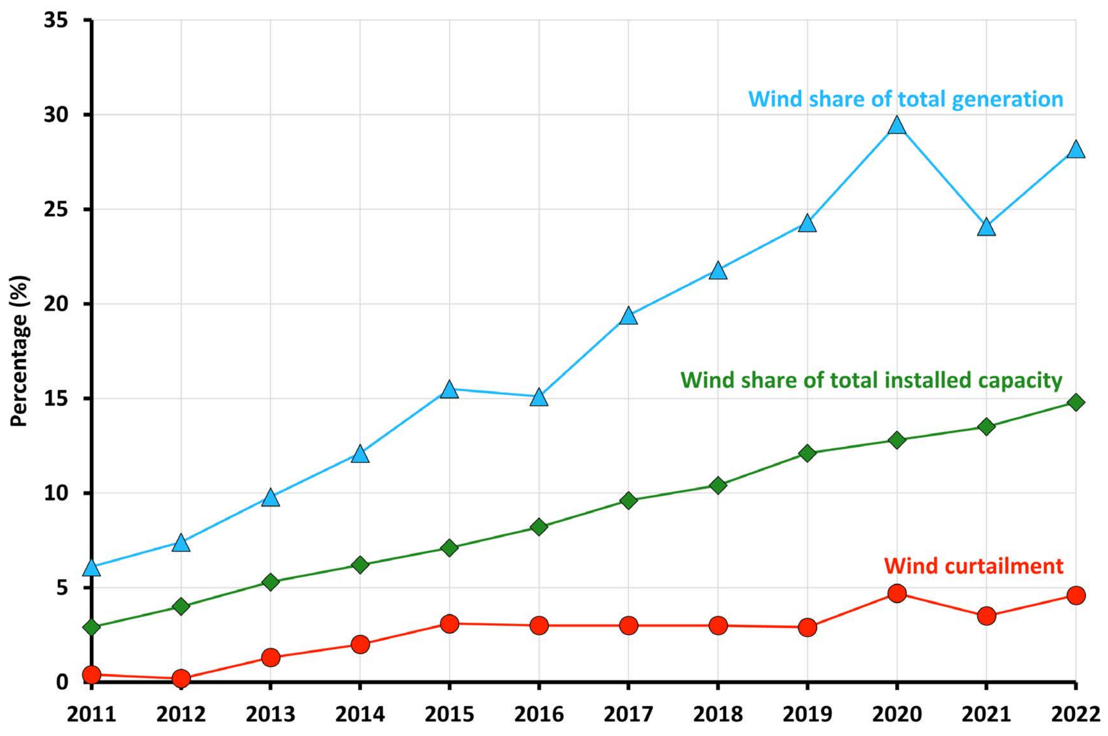



**Figure 17. Actual wind power curtailment in the UK, plotted along with wind power's share of total installed capacity and share of total generation. Data from [9, 57].**

Our concern is specifically related to the impact of a growing share of VRE in the energy mix. This can be seen in the UK with the growth of wind power over the previous decade (Figure 1). In the UK most offshore wind construction has been done under "Contracts for Difference", a private law contract which guarantees generators a price for electricity generated. Payments for curtailing electricity are compensated via the national electricity network system as part of the contract [56].

Curtailment increases with increasing share of wind power, except in cases where there is a persistent lack of infrastructure to integrate renewable energy. This correlation is also seen in countries where the VRE share is high. Figure 18 compares the levels of curtailment with the share of VRE generation for five cases: Germany, Ireland, Chile, California, and the UK.

Other countries do not show this correlation. Spain is an interesting case as it has almost no curtailment despite high levels of VRE and a significant contribution from nuclear. Like the UK, Spain deals with the variation of its VRE by varying the loads on fossil fuel generators, and its hydro and pumped storage infrastructure. China mainly has curtailments that, at this stage of development, are essentially random due to the lack of local structure for integrating large amounts of renewables rather than overall dominance of installed VRE.

It is likely that the full effect of demand on curtailment is being masked by insufficient access to both the distribution and transmission networks, and that is certainly the case in the UK where connections to the grid are being delayed for some large solar projects [58]. In the UK, most of the current wind curtailment is part of the National Grid Constraints Payments system. This is currently necessary because a major proportion of wind generation originates in Scotland, but growth in demand is largely from England and there is insufficient electricity transmission capacity between the two [59].

There will certainly be curtailment of electricity from both wind and solar in the future in the UK. Projections show that wind and solar capacities would be both above expected summer minimum demand levels and that times of low demand would result in curtailment [60].

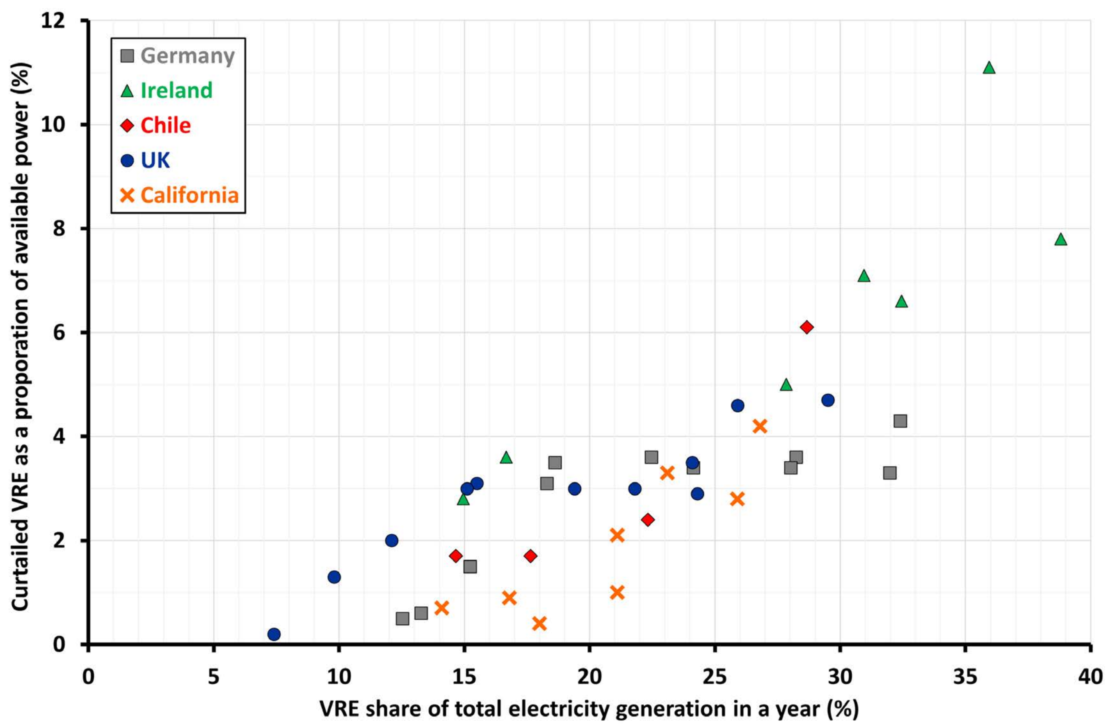



**Figure 18. Effect of VRE share of electricity generation on VRE curtailment for example regions data from [57].**

The issue of negative electricity prices (arising when generation exceeds demand) is particularly common in Germany, the Netherlands, and the Nordic countries. For example, Germany currently pays Denmark to curtail its wind power generation at certain times as interconnections result in periods of negative electricity pricing [61]. A more detailed analysis of curtailment (up to 2020) can be found in [62], which looks at both solar and wind power and how curtailment is tracked through time in response to not only changes in the share of VRE but also to policy decisions.

Nuclear dedicated for baseload electricity generation would certainly increase the levels of curtailment. Preliminary calculations for the High Electrification scenario in Appendix 2 indicate that the impact of 24 GWe of nuclear capacity with flexibility could increase the amount of wind and solar power that would need to be curtailed, exported, or stored from around 40 TWh to around 90 TWh over a year. These estimates were made for the year 2050 by using the demand and renewable utilisation characteristics over the year taken from the actual data for 2021 recorded over 5-minute intervals for Great Britain [32]. As such they are only rough estimates but indicate that nuclear dedicated for baseload electricity generation could double the demand-related curtailment of VRE. Flexible support of VRE using nuclear cogeneration would not remove the underlying issue of curtailment, but could limit it and also provide an alternative use for the curtailed electricity as detailed in Section 4 and Appendix 3.

# Appendix 5: New Technologies

In the period to 2050 there are several technologies that will become available with the potential to tackle the problems involved in reaching net zero and integrating VRE into the electricity mix. Figure 19 shows how the cost of the electricity generation varies with capacity factor. The data for this figure comes from the BEIS/DESNZ electricity cost studies [17, 18, 24], apart from BECCS which comes from work carried out for BEIS [63]. The main line of development is considered below.

## Carbon Capture and Storage (CCS)

Natural gas with CCS, which plays a significant role in the DESNZ High Electrification scenario, is very sensitive to natural gas prices. This means that, even at high capacity factor (92%) the LCOE is likely to lie between £125/Mwh and £200/MWh. The increase as capacity factor falls makes it expensive to use for peaking support.

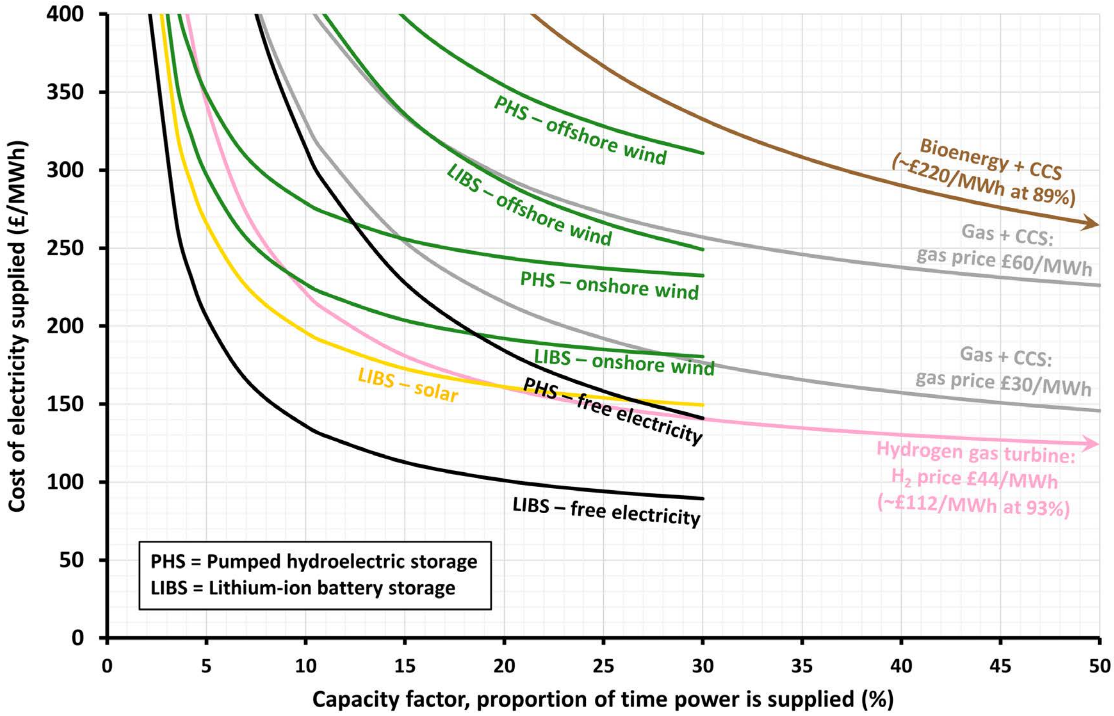



**Figure 19. Variation in the cost of electricity with capacity factor for a range of technologies that will be introduced in the period up to 2050, including energy storage, hydrogen fuelled generation, and CCS.**

### BECCS

BECCS can provide negative $CO_2$ equivalent emissions, which enables the residual emissions from the carbon footprints of low-carbon energy sources to be offset. The DESNZ High Electrification scenario needs about 1 $MtCO_2$/yr of negative emissions to reach net zero by 2050 and accounting for other energy requires as much as 50 $MtCO_2$/yr.

BECCS could provide this through ~1 TWh and ~50 TWh contributions to electricity generation (or around 0.125% and 6.25% share of the total electricity generation) respectively. BECCS is an expensive technology however, and is best used at high capacity factors to minimise the unit cost of the electricity it generates. At a capacity factor of 89% the LCOE is around £220/MWh, so the total extra cost of displacing wind capacity for -1 $MtCO_2$ would be ~£160 million; for -50 $MtCO_2$ £8 billion. BECCS should not be used for peaking support.

### VRE with Energy Storage

Solar and wind with energy storage are also expensive options for peaking support. The use of pumped storage is expensive (even with free electricity), and there is not much scope for expanding existing resources. The use of batteries is cheaper and an obvious option for solar PV. However, batteries are most useful for supporting VRE within distribution networks but would be inadequate to use for grid support (see Section 3.1 and Figure 9). Also, batteries have limitations on storage capacity which makes them more suitable for diurnal variations, not for the longer-term support that wind requires. All options have high costs for peaking support with low capacity factors.

If reasonably priced nuclear hydrogen can be produced, it would provide a useful source of support for the variation in power between summer and winter, at capacity factors over 30%.

Table 8 looks at the costs of these technologies in 2050, using in the DESNZ High Electrification scenario studied in Appendix 2. Some estimates of the associated emissions are also made.

The DESNZ report on these scenarios recognises the extremely low capacity factors (~1%) of peaking plants which occur because of the high level of VRE [4]. However, the report does not emphasise that the LCOE of several

**Table 8. Estimated costs (in 2023 money) of electricity generation for the DESNZ High Electrification scenario in 2050 from the analysis in Appendix 2. The anticipated total electricity generated in 2050 is 836 TWh in the UK, with consumption somewhat less at 792 TWh because of exports. The $CO_2$ equivalent emissions are based on data from Table 5 In Appendix 2.**

| | Capacity (GW) | Capacity factor (%) | Share of generation (%) | LCOE (£/MWh) | Cost of electricity (£bn/yr) | Estimated Emissions ($MtCO_2eq/yr$) | Share of emissions (%) |
|---|---|---|---|---|---|---|---|
| Solar PV | 90 | 8.0 | 7.3 | 45 | 2.7 | 4.34 | 5.79 |
| Onshore wind | 44.4 | 32.9 | 15.0 | 59 | 7.5 | 5.25 | 7.02 |
| Offshore wind | 103.6 | 43.2 | 42.0 | 78 | 29.3 | 5.54 | 7.40 |
| Hydro | 1.62 | 28.1 | 0.5 | 133 | 0.5 | 0.03 | 0.04 |
| Bioenergy | 3.8 | 13.0 | 0.5 | 495 | 2.1 | 1.40 | 1.87 |
| Bioenergy + CCS | 9.77 | 27.7 | 2.7 | 470 | 11.2 | -11.35 | -15.16 |
| Gas + CCS | 9.77 | 27.7 | 2.7 | 175 | 4.2 | 6.52 | 8.72 |
| Nuclear | 24 | 84.7 | 21.0 | 80 | 14.4 | 1.98 | 2.65 |
| Hydrogen | 45 | 2.2 | 1.0 | 648 | 5.7 | 20.13 | 26.89 |
| Unabated gas | 84 | 1.2 | 1.0 | 1139 | 9.8 | 37.74 | 50.44 |
| Pumped hydro | 2.74 | 17.0 | 0.5 | 207 | 0.9 | 0.08 | 0.10 |
| Battery storage | 12.08 | 27.6 | 3.4 | 103 | 3.0 | 3.18 | 4.24 |
| | **Total 431.5** | | | **Average 105** | **Total 91.7** | **Total 74.83** | |

of the technologies are extremely high, notably in excess of £1,000/MWh in the case of unabated natural gas. Appendix 2 shows that the estimated cost of gas-powered peaking plants adds ~£10 billion annually to the total cost of electricity supply, which is over 10% of the total cost. This will make it difficult to justify such an investment, and unless cheaper solutions are found, the result could be blackouts or imposed demand-side controls. The High Electrification scenario also implies that the capacity factors for wind power and nuclear are lower than the anticipated values in the cost reports. This implies that significant amounts of solar and wind power will be curtailed, and the nuclear plants will need some degree of load/demand following. This also adds costs to the scenario.

There is also a disturbing effect of the low capacity factors on the estimated $CO_2$ equivalent emissions in 2050, for combustion systems, most of the emissions come from burning fuel and as such, emissions/TWh are not affected by capacity factor. However, carbon footprints associated with the construction and materials making up the power plants are very sensitive to low capacity factors. Unabated gas and hydrogen generation show large shares of $CO_2$ equivalent emissions. In the case of emissions from hydrogen production, it is assumed that the hydrogen is produced by steam reforming of natural gas with CCS. Despite the CCS, $CO_2$ emissions and methane emissions from natural gas exploitation result in significant emissions from use of hydrogen.

In the future, as global carbon emissions decrease, the contribution to carbon footprint from construction and materials will also decrease and possibly, eventually become insignificant. Until then, these emissions are significant and difficult to control, and are often being produced in countries with primary sector economies. Most of the power production facilities to be used in 2050 have yet to be built. It is irresponsible to build more gas plants for such low levels of usage. Even with life extension of the plants to recover costs and justify emissions the use case is poor.

Removing unabated natural gas from the mix would result in the role of generator of last resort falling on hydrogen generation or natural gas and biofuels with CCS. The installed capacity of these technologies would inevitably have to expand to over 100 GW, capacity factors would reduce as a result, and the costs per MWh of generation would increase. At some stage finding developers willing to invest in new plants would presumably become difficult and maintaining a safe electricity supply could also become a challenge as a result [64].

# Appendix 6: Nuclear Hydrogen and Cogeneration

The production of hydrogen is becoming an important process in moving to net zero. As well as being a fuel itself, hydrogen is a first step in creating synthetic fuels. Hydrogen, unlike electricity or heat, can be stored for long periods and can be part of the solution for coping with the variation in energy demand between summer and winter.

Hydrogen was chosen for this study as the technology for cogeneration to support VRE intermittency because the requirement for low-carbon hydrogen production by 2050 is high enough for it to be a realistic endeavour towards which nuclear energy can be dedicated. Production of nuclear hydrogen can be done mainly with electricity or mainly with heat. To achieve the lowest production costs with a mixture of LWR, SMR and AMR infrastructure, both heat and electricity will be important.

In addition to hydrogen production, this section also considers the wider range of cogeneration potential. One important aspect of this is that both high-grade heat (>500°C) and low-grade heat (<300°C) have their place in getting the most utility out of nuclear plants and facilitating the drive to net zero. It will be shown that enabling the full potential of nuclear cogeneration will require substantial investment but would reduce emissions and the overall cost of achieving net zero, whereas retaining the use of fossil fuels with CCS will not.

**Methane Reformation**

Hydrogen is currently produced by reforming methane with steam by either heating the mixture by burning natural gas to heat the process reactor (steam reforming), or by adding some oxygen to the mixture and heating as part of the reaction process (auto reforming). This route has been a cheap way of making hydrogen, but it has the downside of high $CO_2$ emissions, and it is very sensitive to the price of gas. The use of CCS to remove $CO_2$ from both the heating of the process reactor and the reforming process is likely to be the main lower-carbon method of making hydrogen, until electrolysis using renewable or nuclear electricity (and heat) becomes cheap enough to provide an alternative.

Table 9 shows the cost of steam reforming of methane with CCS today and projected to 2050, for different natural gas prices, using data from the 2021 BEIS report on hydrogen

**Table 9. The variation in cost of producing hydrogen by steam reforming of methane with CCS (2023 money) [65].**

| Price of natural gas £/MWh | Cost of $H_2$ in 2023 | | Cost of $H_2$ in 2050 | |
|---|---|---|---|---|
| | £/MWh | £/kg$H_2$ | £/MWh | £/kg$H_2$ |
| 10 | 40 | 1.6 | 44 | 1.7 |
| 20 | 57 | 2.2 | 61 | 2.4 |
| 30 | 73 | 2.9 | 78 | 3.1 |
| 40 | 90 | 3.6 | 95 | 3.7 |
| 50 | 107 | 4.2 | 111 | 4.4 |

production costs [65]. The cost increases slightly due to an expected increase in carbon price for the residual $CO_2$ equivalent emissions. The wholesale price of natural gas has never been stable, varying between £10/MWh and £25/MWh between 2010 and 2020. A surge in price occurred following the invasion of Ukraine by Russia in 2022, with a peak in December 2022 at ~£150/MWh [65] as can be seen in Figure 20. The price in 2023 has been around £35-40/MWh. The future price of natural gas is uncertain, but the potential volatility in price situation is a good reason to avoid committing to making hydrogen from gas.

The costs of making hydrogen by steam reforming of methane with CCS include an element of carbon pricing. This is because only about 90% of the $CO_2$ ends up in the carbon store, due to inefficient removal and leakage [67]. There is also the issue of methane release during natural gas extraction and transport. It has now become possible to measure methane release rates more effectively and the move to nonconventional gas sources is linked to increased methane releases. The impact of the residual carbon footprint has led to some vigorous debate as to the future of hydrogen derived from gas with CCS [68, 69]. Whereas the carbon footprint deriving from the lifecycle of materials and construction for all applications will reduce as the energy sector reduces its $CO_2$ equivalent emissions, the residual emissions from the use of fossil fuels with CCS may be more intractable.

There are many alternatives to reforming of methane to produce hydrogen. A full list of options is discussed in reference [70], but only the most likely choices are examined here. Note also that this reference uses a capacity factor for solar PV of 20%, which is incorrect for the UK, where it is close to 10%.

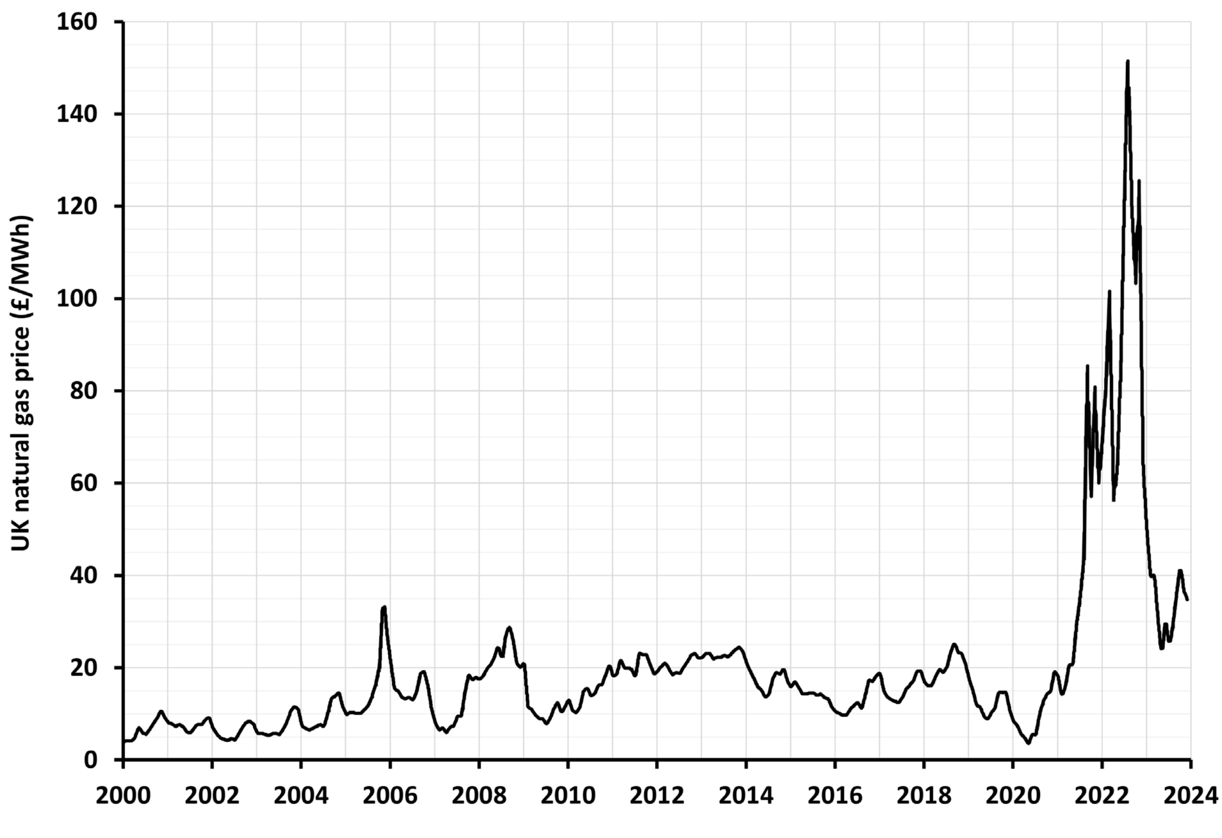



**Figure 20. UK Natural Gas national benchmark price since 2000 [66].**

**Electrolysis**

As VRE mainly produces electricity, the obvious choice for producing hydrogen is electrolysis of water. Over the last 20 years there has been a surge of interest in water electrolysis, resulting in increased efficiencies and reduced costs. The three main technologies are alkaline, PEM, and SOEC (also known as steam electrolysis – essentially a solid oxide fuel cell operating in reverse). Both alkaline and PEM electrolysis are low-temperature processes with comparable costs. PEM uses platinum group catalysts which are expensive but recyclable and is currently moving to higher efficiencies (~70%). SOEC uses cheaper catalysts and is a high-temperature process that can take advantage of the lower free energy required to split water at higher temperature, with the balance of energy supplied as heat rather than electricity [71, 72]. SOEC is developing rapidly and introduction of more efficient fast ion conducting oxide membranes will allow the operating temperature to be reduced from ~850°C to below 650°C. Most systems use oxygen ion conduction, but there is research towards using proton solid oxide membranes. The main concern is reduction in efficiency with time, which limits membrane life. Figure 21 shows the energy input needed to split water for PEM and SOEC technologies. The SOEC data used in Figures 21, 22 and 23 in this section are not from the BEIS report [65], but from SOEC developers [73, 74].

The SOEC option is of great interest for nuclear applications due to the necessity for high temperatures and will likely be the eventual cheapest route to hydrogen production. There is also the possibility of co-electrolysis of water and $CO_2$ which is a potential route for synfuel manufacture. Steam must be supplied, which can be provided by a nuclear plant, but currently SOEC is being aimed at sites where there is significant high temperature waste heat, which form a niche market. The amount of heat required at higher temperatures depends on how the SOEC is operated,

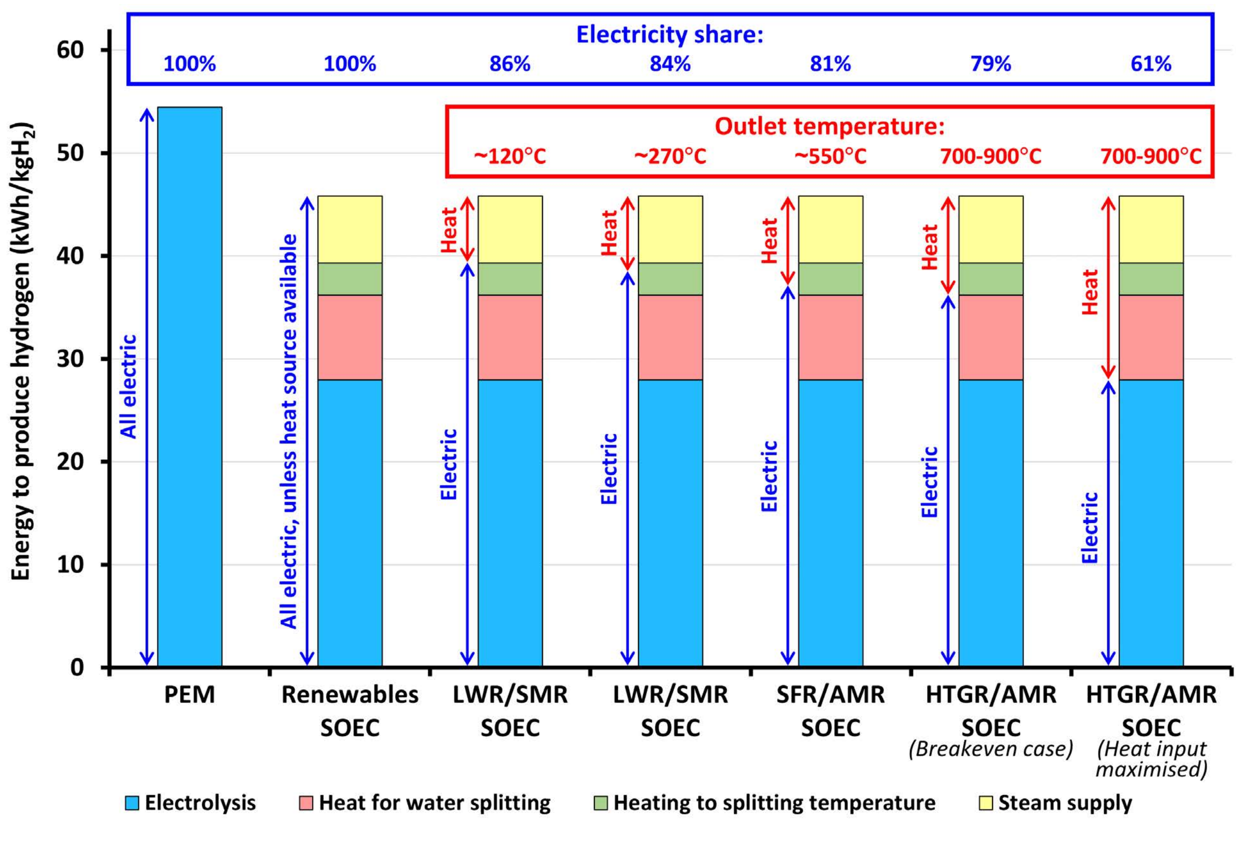



**Figure 21. Comparison of the energy input needed to split water for the PEM and SOEC technologies. SOEC systems can operate in modes with different heat and electricity inputs, depending on the availability of heat sources for a range of temperatures [73, 74].**

either in equilibrium so the resistive heating balances the requirement, or exothermically where the resistance heating exceeds the requirement and is used to heat the inlet steam to the required temperature (see Figure 22). This opens the option of using either AMRs that can provide steam at the required temperature (the most efficient case), or SMRs with steam at 100-270°C, which is slightly less efficient. Maximising the use of heat (the mode on the extreme right of Figure 21 (page 61) is not usually desirable as the rate of hydrogen production is limited, compared to higher voltages and higher resistive heating. As a result, the share of electricity in the input energy is around 80% or higher. Another option is to use grid electricity with nuclear heat.

Figure 22 illustrates the sensitivity of hydrogen cost to capacity factors for PEM and SOEC electrolysis. Even with free electricity the cost of hydrogen production increases sharply as the capacity factor decreases, because of the impact of fixed costs associated with electrolysis (mainly capital costs). For a fixed electricity price, SOEC is cheaper than PEM, even if the heat input is from resistive heating in the cell [73]. If the heat is free, using waste heat from other industrial processes, SOEC is even cheaper.

Use of nuclear power with heat input also reduces the cost from the all-electric case. The reduction is larger for AMR systems that can deliver super-heated steam (550-850°C) as shown in Figure 21, but is still significant for SMRs that would deliver superheated steam at ~300°C or even steam from the low pressure turbine at 120°C. The main point to note is that sources of electricity with high availability factors are preferred, as the electrolysers have a high capital cost. There is clearly an opportunity for application to nuclear hydrogen production, particularly using AMRs with high-quality heat supply.

Figure 23 compares hydrogen production costs for solar and wind using PEM electrolysis with various nuclear power options. The variations with capacity factor are larger as both the power source costs and the electrolysis costs are

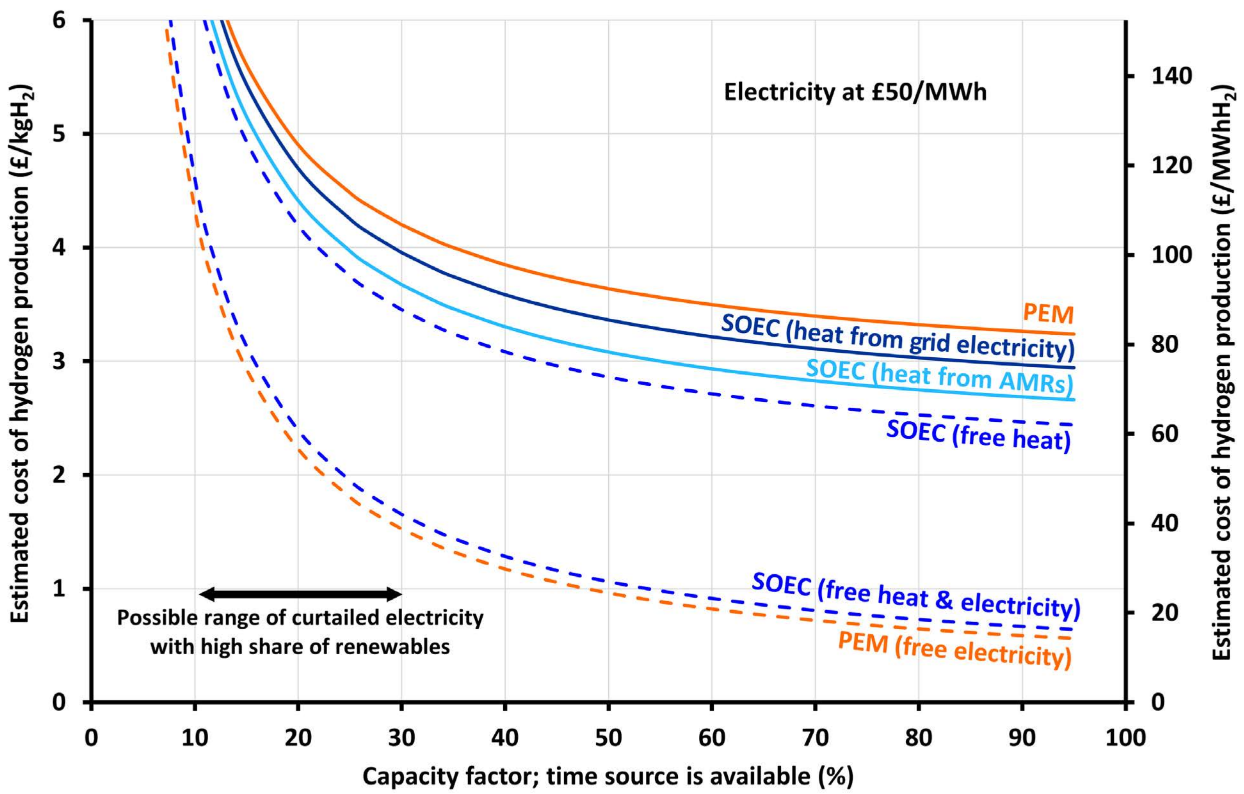



**Figure 22. Comparison of the cost of PEM and SOEC electrolysis hydrogen production costs as a function of the availability of the power and heat source (2023 money) [73, 74].**

sensitive to the capacity factor. Hydrogen production from dedicated solar PV is very expensive, despite the low cost of solar electricity, as the capacity factor is limited to around 10%. Both onshore and offshore wind are predicted to have large increases in potential availability towards 2050, with associated reductions in costs for dedicated hydrogen production. However, most of the wind energy is targeted at grid supply and only excess solar and wind are likely to be on offer to make hydrogen. For reference, a curve is included on Figure 23 to illustrate the possible price of curtailed VRE in the range anticipated in the BEIS 2021 study [65].

The hydrogen production costs from VRE are significantly higher than the cost of hydrogen from steam methane reforming with and without CCS, using the price of natural gas from 2021 or earlier. Since the disruption in natural gas prices, the price of hydrogen production from natural gas has become more uncertain.

At the price of nuclear electricity based on the strike price of Hinkley Point C, hydrogen production costs would be much greater than those from wind power and do not appear on Figure 23. Getting the price of nuclear electricity down is the first step in achieving competitive nuclear hydrogen production. In Figure 23 nuclear hydrogen costs are shown for a nuclear cost of £40/MWh, which is projected for SMR and AMR plants by 2050 [27]. With high nuclear capacity factors, and particularly using HTGR technology and SOECs, it should be possible to achieve competitive hydrogen production costs. As technologies develop it is worth making a goal of £1/kgH$_2$ and there is an ambition in the USA for $1/kgH$_2$ [75].

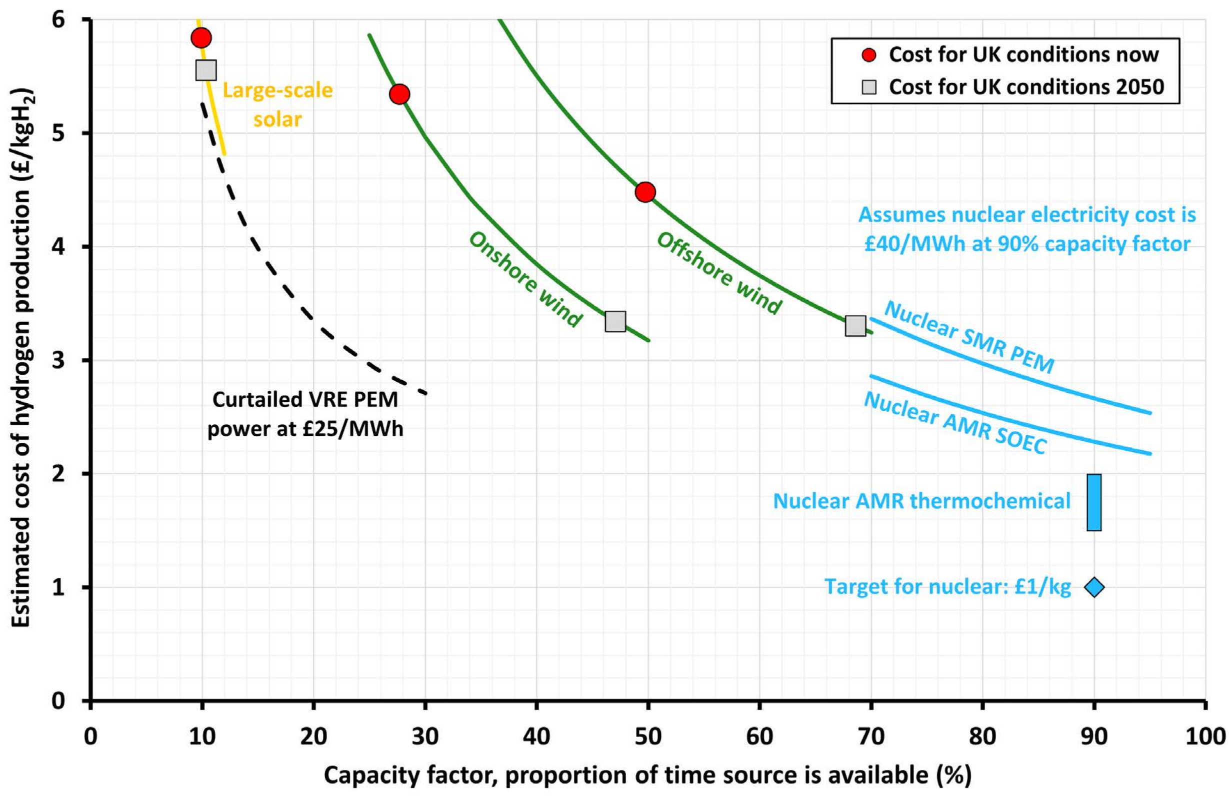



**Figure 23. Comparison of solar, wind and nuclear cost of hydrogen production as a function of capacity factor (2023).**

**Thermochemical Cycles**

An alternative to electrolysis that may provide cheaper hydrogen for HTGRs, is to use thermochemical cycles. There are several cycles that could be used but the most work has been done on the Sulphur-Iodine (S-I) and the Copper-Chlorine (Cu-Cl) cycles [70]. The S-I cycle needs temperatures in excess of 800°C but is ~60% efficient, while the Cu-Cl cycles needs lower temperatures of 350-500°C but is less efficient at ~49%. Some thermochemical routes incorporate an electrolysis stage, such as the Cu-Cl cycle and a version of the S-I cycle, which use both electricity and heat. These processes have been demonstrated at a bench scale in several locations. The Japan Atomic Energy Agency (JAEA) focused on the S-I cycle as part of its work on applying HTGRs to industrial applications [76]. There has also been a feasibility study in the UK on thermochemical cycles using nuclear power – the final report of the study had a positive conclusion that [77]:

> *"...thermochemical hydrogen production has the potential to deliver a step-change increase in UK hydrogen supply from 2040 onwards and a potential reduction in cost to supply a growing UK hydrogen market."*

In the same competition there was another feasibility study on nuclear cogeneration with hydrogen production [78]. This study also saw a long-term potential for the thermochemical cycles but favoured the more immediate potential of SOEC as the TRL was higher.

Electrolysis systems are packaged like batteries in compact units and made into modules that can be removed for servicing or replacement. This would be difficult to do with the thermochemical processes given their reliance on hazardous materials like hot concentrated sulphuric acid or chlorine. Hydrogen is an explosion hazard, so location of hydrogen production plants adjacent to nuclear plants will need careful design to ensure safety. This is also being investigated in the JAEA work [78].

**Production of Synfuels, Syngas and Ammonia**

A supply of hydrogen is a starting point to produce synfuels, syngas and ammonia. There is also a route using pyrolysis and organic waste or biomass. Both routes are potential applications for cogeneration that can be used as part of the strategy to support VRE.

Producing synfuels from hydrogen relies on reactions with $CO_2$, initially through the Reverse Water-Gas Shift (RWGS) reaction to make syngas – a mixture of hydrogen and carbon monoxide (CO) which releases some water [79]. Following this, the Fischer-Tropsch (FT) reaction is used to produce methane and higher hydrocarbons by first reacting hydrogen and carbon monoxide to produce methane and water, then reacting hydrogen and simpler hydrocarbons (starting with methane), to produce heavier hydrocarbons. These heavier hydrocarbons can be used in diesel, aviation, and automotive fuels.

These reactions need suitable catalysts, such as nickel for RWGS, and iron or cobalt for the FT reaction. The RWGS reaction needs to be at a high temperature (>800°C) and is slightly endothermic. The FT reaction is strongly exothermic, and the optimum temperature is around 300°C. It is also possible to use $CO_2$ directly with hydrogen to produce the required hydrocarbons (alkenes) at temperatures around 300-350°C and pressures around 2.5 MPa with copper as a catalyst [80]. Higher temperatures favour the production of methane rather than longer chain hydrocarbons. Electrocatalytic methods are also possible at low temperatures and pressures. This type of synthetic fuel synthesis fits in well with the availability of both heat and electricity to provide a framework for production, and also to make use of any heat generated in the production. Although the FT process was developed in 1920 it remains an area of intense research and the direct use of $CO_2$ could have large impact on costs.

Ammonia synthesis also has a long history with the Haber-Bosch process, dating from 1909. There has been recent interest in ammonia synthesis as part of the route to net zero once a supply of clean hydrogen is available. As well as continuing interest in existing uses (e.g. fertilizers and explosives), the possibility of using ammonia as a marine fuel has been raised, as it has a higher volumetric energy density than hydrogen and is easier to store and transport [81]. Ammonia synthesis is slightly exothermic and is most efficient in the temperature range 450-500°C. Iron was the original catalyst for the process but there is potential for improved production efficiency with new catalysts based on nickel or cobalt. The process can also be enhanced by the use of a dielectric barrier discharge reactor with ceramic catalysts, which would require electrical power. Ammonia production would work well alongside synfuel synthesis as part of a nuclear cogeneration park.

Pyrolysis of organic materials is a process using heat to convert biomass and organic waste (including plastics) into a range of useful products:

- Synfuels as substitutes for petrochemicals or feedstocks for new plastics.
- Syngas.
- Biochar which locks up carbon and can be used a soil conditioner or a replacement for charcoal.

The temperatures required are generally from 150-1000°C depending on the feedstock. Direct use of nuclear heat is possible, but for some processes resistive heating or microwaves using nuclear electricity, or combustion of nuclear hydrogen are better options for nuclear cogeneration. The range of possibilities is too large to explore in this report. A review of the area is given in reference [82] and examples of the use of microwaves with water added to the organic materials is discussed in reference [83], and for sewage sludge treatment in [84]. Pyrolysis has potential for development and wide application, replacing incineration of organic waste.

**Direct Air Capture of $CO_2$**

In current assessments of the future role of nuclear, air capture of $CO_2$ and desalination are frequently discussed. Air capture of $CO_2$ predominately uses heat. Desalination can use either heat or electricity depending on the environment in which the process is carried out.

There is considerable activity on Direct Air Capture (DAC) of $CO_2$, and larger-scale trials have begun. The two main processes are use of potassium hydroxide solutions to capture the $CO_2$, then heating it to around 900°C to release it; and the use of solid sorbents, where the $CO_2$ is adsorbed on high surface area materials, with release temperatures below 100°C [85]. Trials have enabled the cost of these processes to be confirmed and there is a drive to get the price down to \$100/t$CO_2$ by 2050 [86]. The solid sorbent method could be used with waste heat from nuclear power plants and this has been studied as part of a project coordinated by EDF as part of preparations for Sizewell C [87]. The project is funded in-part from the DESNZ DAC and Greenhouse Gas Removals innovation programmes. Sizewell C has the potential to capture 1.5 Mt of $CO_2$ per year and to reduce the cost of DAC (without storage and disposal) from the current £600/t to £200/t. The demonstration project, in partnership with the University of Birmingham, Atkins, Doosan Babcock, and Strata Technology, has been underway since 2020 and the main design and conformation testing has been done. The demonstration plant should start operation in late 2025 and should capture 100 t/yr. A 50 kt/yr demonstration plant is planned for 2030 if funding is approved.

**Desalination**

The main types of desalination methods that can be applied using nuclear energy are [88]:

- Multistage flash distillation, using direct nuclear heat.
- Reverse osmosis, using nuclear electricity to drive high pressure pumps.
- Hybrid reverse osmosis/distillation designed to minimise energy use and improve water quality.

There have been many studies and demonstrations, and the price of the desalinated water should be achievable around \$0.5-1.0/$m^3$. With current difficulties in maintaining water resources in some parts of the UK, nuclear desalinated water may eventually become a requirement.

**Domestic and Business Heating**

The potential to use heat from nuclear power stations goes further than high temperature applications for electricity generation and industry. Lower temperature heat, including waste heat from condensers, could be used to supply heat for hot water and buildings. District heating for domestic, business and institutional (schools, hospitals etc.) applications is possible if reactors are sited within around 100 km from the end users. The UK already has a heat network using heat from a variety of sources. Currently there are projects in progress for Liverpool, London, Bristol, and Gateshead with a total heat supply of ~0.2 TWh/yr [47]. However, these projects are quite small compared to the existing supply from heat networks (~2% of heat usage, 13 TWh/yr) and the potential to increase the use of heat networks to 20% or more by 2050. Most current heat networks are small communal and district networks with a range of heat sources. In many European countries (particularly Nordic and Eastern European) large fractions of heat supply is provided by networks with dedicated thermal power stations. By establishing a larger role for heat networks in the UK, several key issues for achieving net zero could be made simpler. One such challenge is the need to replace natural gas for domestic heating with a low-cost and effective solution given that heat pumps (the most touted solution) are not helpful in large cities with high housing densities, and accommodation in flats.

The UK Heat Networks Market Overview [47] does not mention nuclear heat as an option and neither does recent advice to Parliament [48, 49]. The Energy Technologies Institute (now part of the Energy Systems Catapult) made a detailed case for SMRs to provide district heating and this includes slight modifications that would enable efficient low grade heat supply [42]. The positive effect on the economics of nuclear plants is significant, and a substantial amount of heat is available to expand heat networks well beyond 20% of heat demand.

### Industrial Process Heat

There is still a lot of work to do before a clear picture of what industry will be like in a net zero economy can be fully imagined. This is beyond the scope of this report so there is only space for some brief remarks:

- Not every type of production is suitable for a nuclear supported industrial park.
- Electricity can replace fossil fuel combustion through resistive, inductive and microwave heating and nuclear hydrogen is a valuable, portable fuel and reducing agent.
- The role of syngas for industrial and domestic use is not clear yet.
- The impact of waste reduction, waste management and a cyclic economy is still being understood.
- A lot of R&D and larger scale trials are needed now on the technologies that will be used to provide low-carbon processing and manufacturing. It is an area that also needs more openness and cooperation.
- Only when industry has working alternatives to fossil fuels will it become clear how much electricity and hydrogen will need to be produced; the same issues also face terrestrial, marine and air transport.

# Appendix 7: Nuclear Flexibility and Thermal Storage

One of most important and frequently quoted limitations for nuclear power is its lack of flexibility. This inflexibility arises because of two constraints: technical and economic.

**Technical Constraints on Nuclear Flexibility**

Technical constraints vary depending on reactor type and are discussed in Section 3.2.1 of the main report. Basically, some level of load following is possible with nuclear reactors, but there will be constraints on the rate of power changes and the minimum power levels to meet safety constraints and minimise structural integrity issues on fatigue. Reactor designs may also require changes to minimise cycling damage. Some AMR designs are more suitable to cycling than others.

**Economic Constraints on Nuclear Flexibility**

The cost of nuclear energy is very heavily driven by the initial capital expense of building the reactor. If the amount of energy generation once it is built is reduced, the investment costs (i.e. the capital costs and sizeable interest accrued during the construction period) must be defrayed from a smaller output, and costs per unit generation rise. As such, the capacity factor becomes a key driver of the cost of power. This effect is generally applicable across all nuclear generation technologies, as capital cost will be expected to be the dominant driver across the board. This means that aiming for near-continuous operation of reactors will be a driving feature of any nuclear scenario.

As is amply explored elsewhere in this paper, one means of keeping the capacity factor high is to use the nuclear heat and/or electricity generated for options which will utilise this capacity when conventional electricity demand from the grid is reduced (e.g. hydrogen production).

One of the main objectives of this report is to identify solutions that allow flexibility of supply of electricity to the grid, but at the same time maintain high capacity factors for the nuclear reactor operation. Nuclear cogeneration and thermal storage are identified as routes to achieve this.

**Nuclear Cogeneration and Hydrogen Production**

There is a simple solution to achieve "flexibility from nuclear" based on nuclear cogeneration with hydrogen production. The simplest case is to use PEM with SMRs, so there is no need to account for heat usage. Figure 24 shows this case.

By building a substantial nuclear capacity to produce hydrogen, it would be possible that when required, part of that capacity could be diverted to support the grid with electricity generation. This is spinning capacity and can be easily dispatched for grid support, at the expense of some hydrogen production. Figure 24 (page 68) shows that reducing the capacity of hydrogen production by reducing the nuclear power production by 45% would almost double the cost of the hydrogen. However, by diverting power to grid support there would be income from the power dispatched. The value of that income would be complex and depend on the demand and supply levels, and the duration of the support.

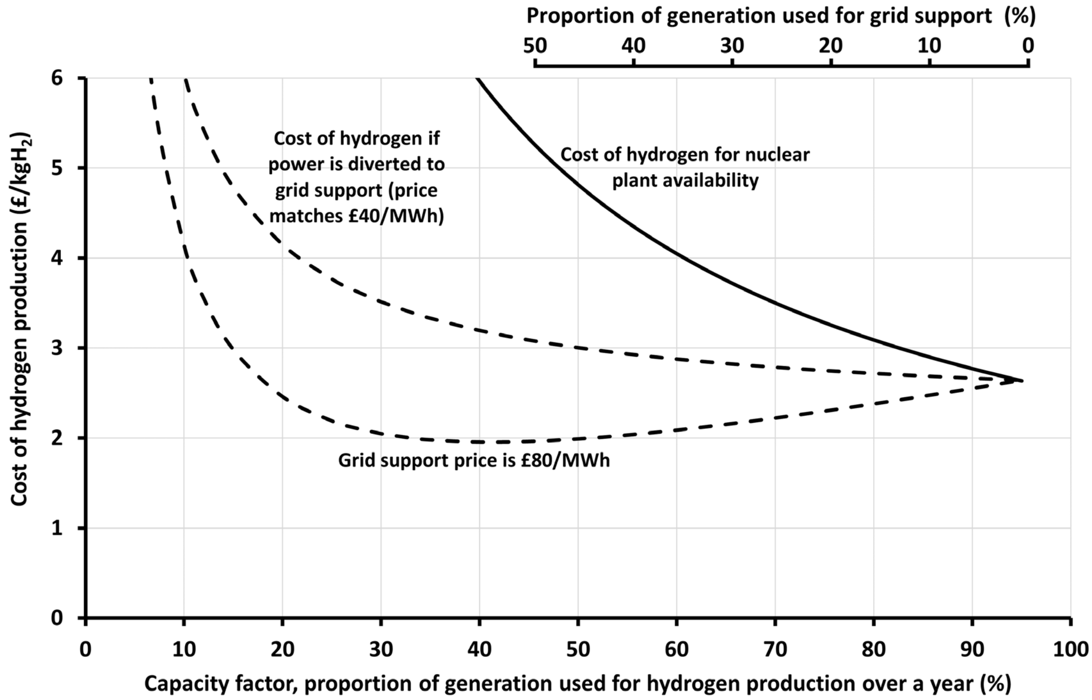



**Figure 24. Illustration of impact of grid support on the price of hydrogen with nuclear cogeneration using PEM and SMRs in 2050 (2023 money).**

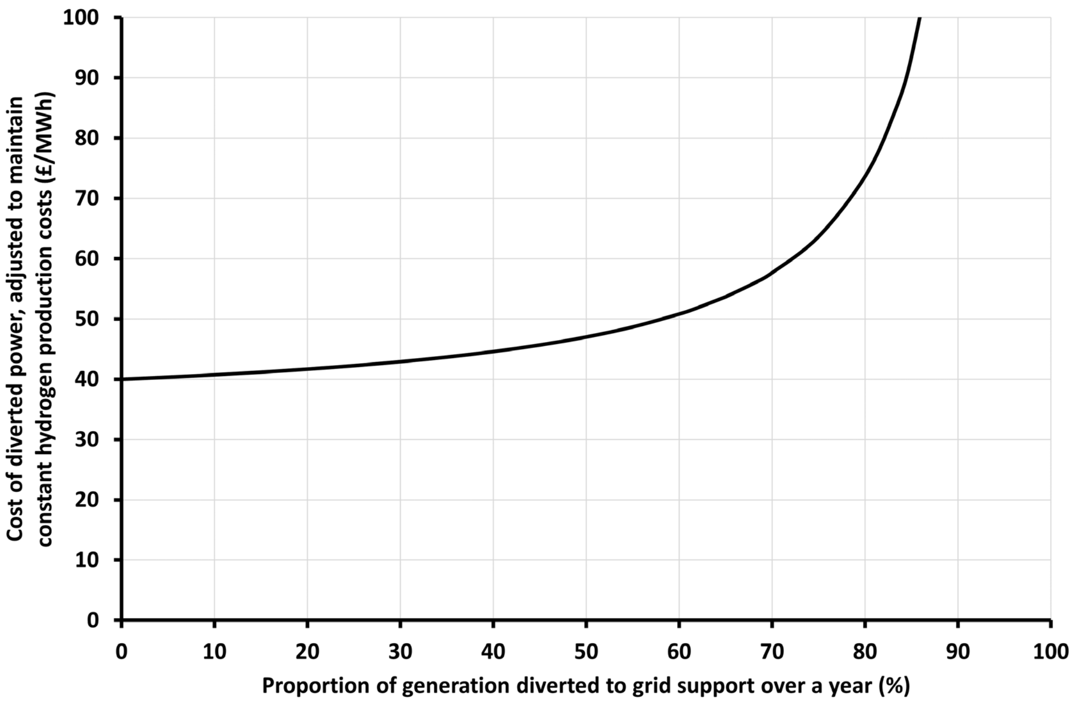



**Figure 25. Example of cost of diverting power from hydrogen production, where the diverted power cost is adjusted to maintain a constant hydrogen production cost.**

Two simple examples are shown in Figure 24 (page 68):

1. Matching the cost of the generation increases the cost of hydrogen by about 10% for a 45% reduction in hydrogen production.
2. Doubling the price of the of the dispatched power gives a substantial reduction in the cost of the hydrogen.

Figure 25 (page 68) shows an alternative cost solution where the electricity cost is adjusted to maintain hydrogen production costs. This is an interesting example as it enables the diverted electricity costs to remain very close to the cost of electricity at the full design capacity factor when a very low fraction of power is needed to meet the grid requirements. Any such scenario is very much cheaper than using other dispatchable power sources at low capacity factor.

This solution is both beneficial to the grid and to hydrogen production. To be effective this would require building dedicated nuclear capacity for hydrogen production of the order of tens of GWe. The technology is already at relatively high TRL. Suitable designs could be demonstrated by the early 2030s, and capacities built to meet the High Electrification scenario in the following 20 years.

**Thermal Storage**

Another approach to gaining flexibility, but without reducing the reactor capacity factor, is by using heat storage. This is mainly relevant to AMRs with outlet temperatures high enough to provide superheated steam or to drive gas turbines. The concept comes from concentrated solar thermal power, where it has been proved effective and economic in countries with abundant sunshine. Molten salts are used to store heat in large, insulated silos, which are then run though steam generators or heat exchangers [34, 35]. The cooled molten salt is then stored in separate silos to be used in the next cycle. This "solar salt" is a low melting point (~220°C) mixture of sodium and potassium nitrates and nitrites. Alternatively, the heat can be stored in large, insulated masses of cheap solid materials such as sand or gravel which are heated and depleted by molten salts [36, 37], but this system has a lower thermal efficiency than the two-tank molten salt option [38].

The use of molten salt thermal storage has several advantages in nuclear applications. The round-trip efficiency is high, and losses are mainly limited to the heat losses during transfer and storage. These decrease with increasing size of the storage tanks, so they are best used for substantial-sized plants. The placing of a low-pressure intermediate circuit between the reactor primary circuit and the energy conversion systems provides protection to the primary circuit in AMR systems using lead, helium, molten salt and particularly sodium coolants.

Several AMR conceptual designs include molten salt thermal storage combined with energy conversion plants up to three times the capacity of the reactor system [39]. This allows continuous operation of the reactor plant while allowing unrestricted load following, including very low power operation. Current proposals use solar salts because of the experience with concentrated solar power, but solar salts are limited to temperatures <560°C, because above this they become unstable. Solar salts are therefore suitable for sodium cooled fast reactor applications, but high temperature gas cooled reactors and other very high temperature designs require an energy vector that will go to higher temperatures. Interest is growing in using mixtures of $NaCl:KCl:MgCl_2$ (27.5:32.5:40.0 mol%, melting point 383°C) and $NaCl:KCl:ZnCl_2$ (13.8:41.9:44.3 mol%, melting point 229°C) [89]. Chlorides containing zinc and magnesium are stable to ~1000°C.

Expressing the costs and range of power provision in a chart is difficult as there are several variables that must be taken into account:

- The reactor operation and costs.
- The size and level of reserve in the thermal storage.
- The size of the enhanced generation and the variable demand.
- The level of cogeneration activity, which is used to ensure the capacity factor on the systems is maximised.

These are not well developed, although there is extensive use of thermal storage for solar thermal power. A programme of work is needed to ensure this option is fully understood and the full potential is captured.

Figure 26 (page 70) attempts to show how the costs of electricity supplied using thermal heat storage and enhanced power production capacity for an AMR system varies as a function of capacity factor on the assumption of a daily cycle. In practice much more complicated usage patterns will be used with storage of heat for longer periods. Figure 26 also looks at the use of electricity or heat by the plant for industrial uses giving added flexibility and cost reductions for low capacity factor supply to the grid.

Figure 26 shows an example of how thermal storage might be integrated with cogeneration to provide a very flexible large capacity for grid support with low capacity factors.

For support at around 30% capacity factor, which is useful for diurnal demand support, the additional costs of the storage and increased power capacity allow a very much lower electricity cost than using additional VRE capacity with pumped hydro or battery storage.

Without cogeneration, the provision of thermal capacity for one day and three times the rated power for the reactor, increases the cost of the plant compared to a reactor with no storage, from £40/MWh to £68/MWh for 90% capacity factor. However, the cost of the electricity increases rapidly for the reactor without thermal storage as the capacity factor is reduced, but for the reactor with storage the cost of the electricity remains the same down to a capacity factor of 30%. Without cogeneration this situation is ideal for diurnal cycling and allows up to three times the power of the system without storage to be delivered with full flexibility. Note that the capacity factor in Figure 26 is the capacity factor for one day of power delivery, not the capacity factor of the reactor. Provided the capacity factor of the power delivery does not drop below 30%, the reactor capacity factor is 90%.

Adding cogeneration to the mix allows the system to deliver power to the grid at lower capacity factor while maintaining the electricity costs at £68/MWh. The effect of using a proportion of the energy (a combination of electricity and heat) from the AMR station for industrial uses is shown in Figure 26 at levels of 25%, 59% and 75% of the energy available. It is assumed that the value of heat recovered is equivalent to the electricity cost (e.g. if the conversion efficiency is 40%, the cost of heat is assumed to be 0.4 electricity cost).

An additional benefit of the cogeneration for industrial production and grid support, is that the thermal storage allows curtailed VRE low-cost electricity to be used for

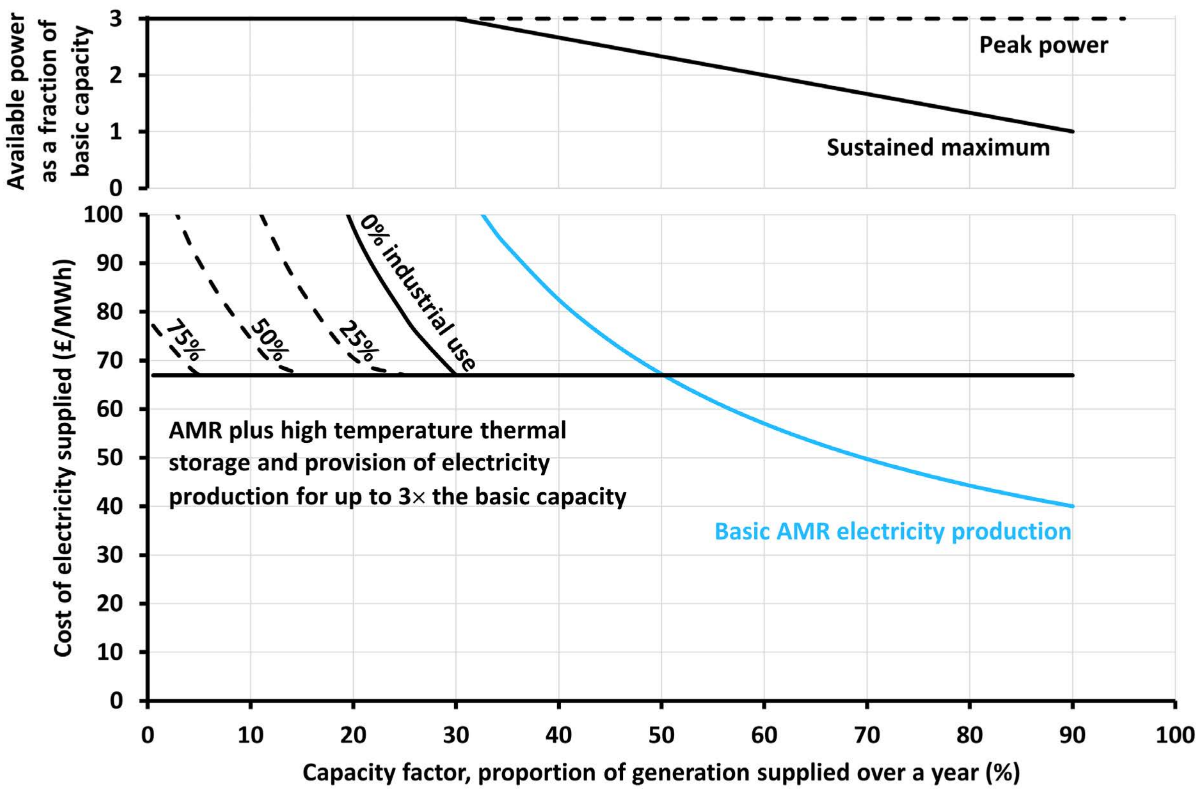



**Figure 26. Costs of electricity supplied using thermal heat storage and enhanced power production capacity for AMR systems as a function of capacity factor on the assumption of a daily cycle. Use of electricity or heat by the plant for industrial uses like hydrgen production gives added flexibility and cost reductions for low capacity factor supply to the grid.**

industrial processes like hydrogen production, without increasing the cost of nuclear of the nuclear cogeneration. This lowers the total costs of AMR cogeneration uses. Without overall system planning, there will be limits to the amount of curtailed VRE that can be absorbed. To make an impact the investment in AMR stations with industrial parks will probably need to be substantial.

Comparing various technologies in Figure 23 with Figures 24-26 gives a good case for building nuclear capacity for both hydrogen production and for variable power supply with thermal storage. This requires the development of SMR and AMR reactor systems with much lower costs than the current GW systems and the construction of long series of builds of reactors of the same type. This would easily provide the cheapest solutions for grid support for integration of VREs.

**Nuclear Cogeneration with High VRE**

In Appendix 3 the DESNZ High Electrification scenario was modified into the Flexible Nuclear scenario to eliminate the use of natural gas after 2040, and to use nuclear cogeneration to provide the flexibility needed to supply several types of grid support. The detail of the technologies used by 2050 is shown in Table 10.

The 24 GWe capacity currently planned to be built as a combination of gigawatt-scale plants and one or more fleets of SMRs would have their focus on hydrogen production (there will certainly be a wider range of applications, but for simplicity only hydrogen production is considered). As described in Figures 24 and 25, power can be switched to grid support for short or long periods, but at low cost provided the fraction time spent on grid support is not too

**Table 10. Estimated cost (in 2023 money) of electricity generation for the Flexible Nuclear scenario in 2050 (described in Appendix 3) with a comparison to the capacity factor of the technology. The $CO_2$ equivalent emissions on a life cycle basis are calculated on data from Table 6 In Appendix 3.**

| | Capacity (GW) | Capacity factor (%) | Share of generation (%) | LCOE (£/MWh) | Cost of electricity (£bn/yr) | Estimated Emissions ($MtCO_2eq/yr$) |
|---|---|---|---|---|---|---|
| Solar PV | 90 | 8.0 | 7.4 | 32 | 1.9 | 4.34 |
| Onshore wind | 44.4 | 32.9 | 15.0 | 59 | 7.5 | 5.25 |
| Offshore wind | 103.6 | 43.2 | 46.0 | 66 | 25.8 | 5.53 |
| Hydro | 1.62 | 28.1 | 0.5 | 133 | 0.5 | 0.03 |
| Bioenergy | 3.8 | 13.0 | 0.5 | 495 | 2.1 | 1.40 |
| Bioenergy + CCS | 10 | 55.5 | 5.5 | 316 | 15.0 | -27.68 |
| Nuclear + $H_2$ production | 24 | 11.9* | 2.9 | 75 | 1.9 | 0.25 |
| AMR + thermal storage | 90 | 7.6* | 7.0 | 67 | 4.0 | 0.58 |
| Hydrogen | 45 | 25.4 | 12.0 | 148 | 14.8 | 22.52 |
| Pumped hydro | 2.74 | 17.0 | 0.5 | 207 | 0.9 | 0.08 |
| Battery storage | 12.08 | 27.6 | 3.4 | 103 | 3.0 | 3.18 |
| | **Total 427** | | | **Average 90** | **Total 77.4** | **Total 15.47** |

* *The nuclear capacity factors here denote the fraction of capacity used to power the grid. In the case of the Nuclear + $H_2$ case, which corresponds to gigawatt-scale and SMR generation, the assumption is that the total capacity factor is 93%, so the remaining 81.1% capacity factor is used for cogeneration activities and for simplicity hydrogen production. In the case of AMR + thermal storage, the 7.6% corresponds to the capacity factor of the enhanced capacity for power generation enabled by the separation of the reactor operation from generation by using the thermal storage and a large generating set. This corresponds to 22.8% capacity factor of the reactor. Again, a total reactor capacity factor of 93% is assumed, and the remaining 70.2% capacity factor is used for cogeneration.*

high – in this case around 11% of the time. In addition to the LWR based nuclear plants, there is also a substantial capacity of AMR generation. The 90 GWe is based on the proposal outlined in Figure 26, where HTGRs with a thermal power around 60 GWth (the electrical power without storage would be 30 GWe) are used to feed a high temperature heat store that can be used for both electricity generation and industrial uses of heat. The size of this store will need to be optimised but it would need to have a minimum capacity of several hours at the full power rating but ideally longer. The maximum generating capacity as stated would be 90 GWe. This arrangement would be used for the shorter-term support of the grid and particularly when both solar and wind power are not available. Only around 7.6% of the of the available generation is used for grid application and the balance would be used for industrial application including high efficiency hydrogen production. The large amount of flexibility in the thermal storage solution also allows the use of curtailed solar and gas generation, which has an additional beneficial effect on reducing the costs and emissions from the renewable energy.

In addition to the nuclear generation there is an increased share of BECCS and hydrogen. The BECCS electricity is a valuable source of additional dispatchable power, but at rather a high cost. This is offset by the production of negative emissions.

In the DESNZ High Electrification scenario, hydrogen power is assumed to be used only for very low capacity factor peaking adjustments to the grid supply. Simple hydrogen gas turbines are very effective for doing this, but hydrogen has a larger role because of its ability to replace fossil fuels as a way of storing energy for long periods. For this reason, the hydrogen (using combined cycle high efficiency generation) capacity factors are increased to allow for a role in providing extra power in the winter both at times of very high demand and also for shorter periods of low supply.

In addition to the supply of around 850 TWh of electricity to the grid, this scenario also supplies a mix of heat and electricity to industrial applications to a maximum of around 400 TWh of electricity or 1,000 TWh of heat per year (a mixture of high-quality and medium quality). This is equivalent to 300 Mt of low-carbon hydrogen but in practice would be used for a wider range of applications. Contributions to the reduced costs and more negative emissions come from increasing the solar and offshore wind capacity factors by use of curtailed power in the nuclear industrial parks and full effective use of the nuclear capacity through cogeneration.

Table 11 (page 73) summarises the impact of moving to the Flexible Nuclear cogeneration solution, in terms of costs and $CO_2$ equivalent emissions by 2050. This shows a significant but not exceptional reduction in costs of ~15%. Perhaps the more important impact is on $CO_2$ equivalent emissions. The change from significant residual total emissions to useful, negative total emissions, would make the task of achieving net zero easier. The total negative emissions are achieved by two factors: an increase in BECCS capacity factor, partly enabled by enhanced nuclear flexibility; and replacing use of natural gas with and without CCS with lower emission generation.

The increased flexibility of the nuclear generation is enabled by the larger use of dedicated nuclear for hydrogen production (or more realistically a wider range of industrial and caron reduction activities). A major part of the flexibility comes from the use of AMRs with both cogeneration and thermal storage. This is a complex area and deserves more detailed attention.

It is important to note that these estimated impacts make many assumptions, and more detailed and realistic studies are required to confirm them and to ensure the full impact is gained. Table 11 also shows some speculation on the possibility of using GW-scale and SMR reactors with more flexibility. Even in the original DESNZ High Electrification scenario there is scope for 10-14% cogeneration from nuclear. This could include nuclear heat to facilitate use of curtailed electricity from VRE or for air capture of $CO_2$.

This study does not explore the use of and income from waste heat from nuclear for low-grade heat networks or even some applications like air capture of $CO_2$. There will be substantial amounts of waste heat from gigawatt-scale reactors, SMRs and AMRs. Use of the waste heat usually requires some reduction in output from the higher temperature application, but generally there is an overall benefit.

**Table 11. A comparison of the impact of the DESNZ High Electrification and the Flexible Nuclear cogeneration scenarios in 2050, on costs and $CO_2$ equivalent emissions.**

| | DESNZ High Electrification scenario (Appendix 2) | Proposed Flexible Nuclear scenario (Appendix 3) |
|---|---|---|
| Total nuclear capacities (GWe / GWth) | | |
| LWR and SMR | 24 / 70 | 24 / 70 |
| AMR | 0 / 0 | 30 / 60 |
| AMR with thermal storage and enhanced generation | 0 / 0 | 60 / >180 |
| Cost of delivering ~840 TWh of electricity to the grid (£bn) | 92 | 77 |
| Averaged levelised cost of electricity (£/MWh) | 105 | 90 |
| Estimated emissions on a life cycle basis ($MtCO_2eq/yr$) | 75<br>(-11.4 from BECCS) | 15.5<br>(-28 from BECCS) |
| Nuclear electricity for cogeneration (TWh) | ~20 | ~400 |
| Nuclear heat for cogeneration (TWh) | ~60 | ~1000 |
| Waste nuclear heat some of which could be used (TWh) | ~500-700 | ~1250 |
| Amount of nuclear hydrogen that could be generated (Mt/yr) | ~15 | ~300<br>(~6 Mt/yr used for generation) |
| Emissions from hydrogen production ($tCO_2/tH_2$) | ~<1 for nuclear<br>~ 6 for steam reforming + CCS | ~<1 |

# References


[1] "Climate Change Act 2008," HM Government, (2008). Online: https://www.legislation.gov.uk/ukpga/2008/27.

[2] "The King's Speech 2024," (2024). Online: https://assets.publishing.service.gov.uk/media/6697f5c10808eaf43b50d18e/The_King_s_Speech_2024_background_briefing_notes.pdf.

[3] "Updated energy and emissions projections 2021 to 2040," BEIS (Department for Business, Energy and Industrial Strategy), (2022). Online: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1111625/updated-energy-and-emissions-projections-2021-2040.pdf.

[4] "Energy and Emissions Projections 2021 to 2040, Annex O: Net Zero and the power sector scenarios," BEIS (Department for Business, Energy and Industrial Strategy), (2023). Online: https://assets.publishing.service.gov.uk/media/6464ac150b72d30013344604/annex-o-net-zero-power-sector-scenarios.pdf.

[5] I. Stewart, "Why is cheap renewable electricity so expensive on the wholesale market?," House of Commons Library, (2023). Online: https://commonslibrary.parliament.uk/why-is-cheap-renewable-electricity-so-expensive/.

[6] C. L. Painter, M. Subki, S. Monti, and F. Reitsma, "Technology Roadmap for Small Modular Reactor Deployment," IAEA (International Atomic Energy Agency), (2021). Online: https://www-pub.iaea.org/MTCD/Publications/PDF/PUB1944_web.pdf.

[7] "Advanced Modular Reactor Research, Development & Demonstration: Phase A," BEIS (Department for Business, Energy and Industrial Strategy), (2022). Online: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1067736/amr-rdd-phase-a-competition-guidance.pdf.

[8] "Nuclear energy for net zero: a strategy for action," Dalton Nuclear Institute, (2021). Online: https://documents.manchester.ac.uk/display.aspx?DocID=55791.

[9] "Digest of UK Energy Statistics (DUKES) Chapter 5: Electricity," DESNZ (Department for Energy Security & Net Zero), (2023). Online: https://assets.publishing.service.gov.uk/media/64c23a300c8b960013d1b05e/DUKES_2023_Chapter_5.pdf.

[10] National Grid ESO, "Future Energy Scenarios," Future Energy Scenarios, (2023). Online: https://www.nationalgrideso.com/document/283101/download.

[11] E. Daly, J. Kar, M. Pani, and V. Finkel, "Facing the future: Net zero and the UK electricity sector," McKinsey & Company, (2022). Online: https://www.mckinsey.com/industries/electric-power-and-natural-gas/our-insights/facing-the-future-net-zero-and-the-uk-electricity-sector#/auth-download/

[12] "Powering Up Britain," HM Gov, (2023). Online: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1147340/powering-up-britain-joint-overview.pdf.

[13] R. Sunak, "Boosting gas capacity is the insurance policy Britain needs while we deliver net zero," The Telegraph, (2024). Online: https://www.gov.uk/government/speeches/prime-minister-rishi-sunaks-article-in-the-telegraph-12-march-2024.

[14] "Energy Secretary takes action to reinforce UK energy supply," HM Government, (2024). Online: https://www.gov.uk/government/news/energy-secretary-takes-action-to-reinforce-uk-energy-supply.

[15] G. Rioseco, S. Smart, J. Lane, S. Wilson, and M. Ho, "Modelling Future Total System Costs in the Eastern Australian Power System of of the National Electricity Market (NEM)," ( 2022). Online: https://www.nuclearaustralia.org.au/wp-content/uploads/2022/07/Gabriel_Rioseco_EA-NuclearPanel-2022-07-20.pdf.

[16] J. Thompson, "Keeping the lights on during the transition to net zero," *Nucl. Futur.*, vol. **18**, pp. 47–53, (2022).

[17] "Electricity Generation Costs 2020," BEIS (Department for Business, Energy and Industrial Strategy), (2020). Online: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/911817/electricity-generation-cost-report-2020.pdf.

[18] "Electricity Generation Costs 2023," DESNZ (Department for Energy Security & Net Zero), (2023). Online: https://assets.publishing.service.gov.uk/media/6556027d046ed400148b99fe/electricity-generation-costs-2023.pdf.

[19] "Civil Nuclear: Roadmap to 2050," DESNZ (Department for Energy Security & Net Zero), (2024). Online: https://assets.publishing.service.gov.uk/media/65aa96bc82fee9000d6f5f91/6.8610_DESNZ_Civil_Nuclear_Roadmap_report.pdf.

[20] L. Waters, "Digest of UK Energy Statistics (DUKES) Chapter 6: Renewable sources of energy," DESNZ (Department for Energy Security & Net Zero), (2023). Online: https://assets.publishing.service.gov.uk/media/64c1322c90b54500143e83c6/DUKES_2023_Chapter_6.pdf.

[21] "Annex A: Net Zero Strategy categories: Greenhouse gas emissions by source," DESNZ (Department for Energy Security & Net Zero), (2023). Online: https://assets.publishing.service.gov.uk/media/640af236e90e076ccf66d71b/Annex_A_GHG_by_NZS_category_Mar2023revision.ods.

[22] T. Gibon, Á. H. Menacho, and M. Guiton, "Carbon Neutrality in the UNECE Region: Integrated Life-cycle Assessment of Electricity Sources," UNECE (United Nations Economic Commission for Europe), (2022). Online: https://unece.org/sites/default/files/2022-04/LCA_3_FINAL March 2022.pdf.

[23] M. Berthélemy, A. V. Soler, M. Middleton, and S. Bilbao y León, "Unlocking Reductions in the Construction Costs of Nuclear: A Practical Guide for Stakeholders," NEA (Nuclear Energy Agency), (2020). DOI: 10.1787/33ba86e1-en.

[24] "Electricity Generation Costs," BEIS (Department for Business, Energy and Industrial Strategy), (2016). Online: https://assets.publishing.service.gov.uk/media/5a8155f2e5274a2e87dbd11b/BEIS_Electricity_Generation_Cost_Report.pdf.

[25] N. Jenkins, "Personal Communication." (2010).

[26] "The Sixth Carbon Budget: Electricity generation," CCC (Climate Change Committee), (2020). DOI: https://www.theccc.org.uk/wp-content/uploads/2020/12/Sector-summary-Electricity-generation.pdf.

[27] E. Ingersoll, K. Gogan, J. Herter, and A. Foss, "The ETI Nuclear Cost Drivers Project: Full Technical Report," (2020). Online: https://esc-production-2021.s3.eu-west-2.amazonaws.com/2021/10/ETI-nuclear-cost-drivers-report-2020.pdf.

[28] E. Ingersoll and K. Gogan, "Missing Link to a Livable Climate: How Hydrogen-Enabled Synthetic Fuels Can Help Deliver the Paris Goals," Lucid Catalyst, (2020). Online: https://www.lucidcatalyst.com/_files/ugd/2fed7a_f532181b09b2455f9f5eecfc97cc58ea.pdf.

[29] S. Allen, "Carbon Footprint of Electricity Generation," POST (Parliamentary Office of Science and Technology), (2011). Online: https://www.parliament.uk/globalassets/documents/post/postpn_383-carbon-footprint-electricity-generation.pdf.

[30] "Large-scale electricity storage," The Royal Society, (2023). Online: https://royalsociety.org/-/media/policy/projects/large-scale-electricity-storage/large-scale-electricity-storage-report.pdf.

[31] "Large-scale electricity storage: Policy briefing," The Royal Society, (2023). Online: https://royalsociety.org/-/media/policy/projects/large-scale-electricity-storage/large-scale-electricity-storage-policy-briefing.pdf.

[32] L. Smith, "Gridwatch," Templar Consultancy. Online: https://www.gridwatch.templar.co.uk/.

[33] C. Matson and J. Knighton, "Renewable curtailment and the role of long duration storage," Lane Clark & Peacock, (2022). Online: https://www.drax.com/wp-content/uploads/2022/06/Drax-LCP-Renewable-curtailment-report-1.pdf.

[34] P. Morilhat, S. Feutry, C. Le Maitre, and J. M. Favennec, "Nuclear Power Plant flexibility at EDF," *HAL Open Sci.*, (2019).

[35] K. Sheikh, "New Concentrating Solar Tower Is Worth Its Salt with 24/7 Power," Scientific American, (2016). Online: https://www.scientificamerican.com/article/new-concentrating-solar-tower-is-worth-its-salt-with-24-7-power/.

[36] "Solar Research Spotlight: Concentrating Solar-Thermal Power," US DoE (Department of Energy), (2018). Online: https://www.energy.gov/eere/solar/articles/fact-sheet-concentrating-solar-power.

[37] R. Jacob, S. Riahi, M. Liu, M. Belusko, and F. Bruno, "Technoeconomic Impacts of Storage System Design on the Viability of Concentrated Solar Power Plants," *J. Energy Storage*, vol. **34**, p. 101987, (2021). DOI: 10.1016/j.est.2020.101987.

[38] Roberto Ponciroli, Haoyu Wang, Richard B. Vilim, Konor Frick, and Cristian Rabiti, "Development of Energy Storage: Cost models," Argonne National Lab, (2020). Online: https://publications.anl.gov/anlpubs/2021/04/167188.pdf.

[39] Y. Zou and M. Subki, "Advances in Small Modular Reactor Technology Developments," IAEA (International Atomic Energy Agency), (2022). Online: https://aris.iaea.org/Publications/SMR_booklet_2022.pdf.

[40] "Guidance on development costs and the nuclear Regulated Asset Base model," DESNZ (Department for Energy Security & Net Zero), (2022). Online: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1120481/development-costs-nuclear-rab-model-guidance.pdf.

[41] R. Taylor, W. Bodel, and G. Butler, "A Review of Environmental and Economic Implications of Closing the Nuclear Fuel Cycle — Part Two: Economic Impacts," *Energies*, vol. **15**, no. 7, pp. 1–31, (2022). Online: https://www.mdpi.com/1996-1073/15/7/2472.

[42] M. Middleton, "Preparing For Deployment of A UK Small Modular Reactor By 2030," ETI (Energy Technologies Institute), (2016). Online: https://d2umxnkyjne36n.cloudfront.net/insightReports/Preparing-for-deployment-of-a-UK-SMR-by-2030-UPDATED.pdf.

[43] T. Roulstone, C. Lloyd, and R. Lyons, "Expanding Nuclear's Contribution to Climate Change with SMRs," *Nucl. Futur.*, vol. **16**, pp. 54–58, (2020).

[44] "UK Energy System Modelling: Net Zero 2050," NNL (National Nuclear Laboratory), (2021). Online: https://www.nnl.co.uk/wp-content/uploads/2023/02/NNL_UK-Energy-System-Modelling_01_ALL_V4-1.pdf.

[45] "Innovating to Net Zero 2024," ESC (Energy Systems Catapult), (2024). Online: https://es.catapult.org.uk/report/innovating-to-net-zero-2024/.

[46] C. Connolly, K. Taylor, M. Bankhead, R. Jarvis, and J. Dean, "Techno-Economic Analysis of Heat-Assisted Hydrogen Production from Nuclear Power," *New Energy Exploit. Appl.*, vol. **3**, no. 1, (2024). DOI: 10.54963/neea.v3i1.234.

[47] Department for Energy Security & Net Zero, "UK Heat Networks: Market Overview," DESNZ (Department for Energy Security & Net Zero), (2023). Online: https://assets.publishing.service.gov.uk/media/64f1b180fdc5d1000d28498a/uk-heat-networks-market-overview.pdf.

[48] B. Mawhood, "Heat Networks and Energy Prices," House of Commons Library, (2022).

[49] J. Miller, "Heat networks," POST (Parliamentary Office of Science and Technology), (2020). Online: https://researchbriefings.files.parliament.uk/documents/POST-PN-0632/POST-PN-0632.pdf.

[50] "HyNet North West: From Vision to Reality," Cadent.

[51] "Delivering one of the world's largest carbon capture projects," Humber Zero. Online: https://humberzero.co.uk/humber-zero-capturing-carbon.

[52] P. Ralon, M. Taylor, A. Ilas, H. Diaz-Bone, and K.-P. Kairies, "Electricity storage and renewables: Costs and markets to 2030," IRENA (International Renewable Energy Agency), (2017). Online: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Oct/IRENA_Electricity_Storage_Costs_2017_Summary.pdf.

[53] V. Jülch, "Comparison of electricity storage options using levelized cost of storage (LCOS) method," *Appl. Energy*, vol. **183**, pp. 1594–1606, (2016). DOI: 10.1016/j.apenergy.2016.08.165.

[54] O. Schmidt, S. Melchior, A. Hawkes, and I. Staffell, "Projecting the Future Levelized Cost of Electricity Storage Technologies," *Joule*, vol. **3**, no. 1, pp. 81–100, (2019). DOI: 10.1016/j.joule.2018.12.008.

[55] "UK hydrogen strategy," HM Government, (2021). Online: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1175494/UK-Hydrogen-Strategy_web.pdf.

[56] "Electricity Market Reform: Update on Terms for the Contract for Difference," DECC (Department of Energy and Climate Change), (2013). Online: https://assets.publishing.service.gov.uk/media/5a7ba1beed915d4147621a18/EMR_-_Update_on_Terms_for_the_Contract_for_Difference_v8.pdf.

[57] H. Bahar et al., "Renewable Energy Market Update: Outlook for 2023 and 2024," IEA (International Energy Agency), (2023). Online: https://iea.blob.core.windows.net/assets/63c14514-6833-4cd8-ac53-f9918c2e4cd9/RenewableEnergyMarketUpdate_June2023.pdf.

[58] "Grid Delays Descending into Farce, Says Solar Energy UK," Elemental Digital. Online: https://www.elementaldigital.co.uk/grid-delays-descending-into-farce-says-solar-energy-uk/.

[59] "What are constraints payments?," National Grid Electricity Systems Operator. Online: https://www.nationalgrideso.com/electricity-explained/how-do-we-balance-grid/what-are-constraints-payments.

[60] I. Staffell, R. Green, T. Green, N. Johnson, M. Jansen, and R. Gross, "Electric Insights Quarterly: Q4 2023," Drax, (2023). Online: https://reports.electricinsights.co.uk/wp-content/uploads/2024/02/ElectricInsights_23Q4.pdf.

[61] M. Plechinger, "Danish wind turbines curtailed like never before," Energy Watch, (2021). Online: https://energywatch.com/EnergyNews/Policy___Trading/article12666098.ece.

[62] Y. Yasuda et al., "C-E (curtailment – Energy share) map: An objective and quantitative measure to evaluate wind and solar curtailment," *Renew. Sustain. Energy Rev.*, vol. **160**, no. September 2021, (2022). DOI: 10.1016/j.rser.2022.112212.

[63] "Analysing the potential of bioenergy with carbon capture in the UK to 2050: Summary for policymakers," Ricardo Energy & Environment, (2020). Online: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/911268/potential-of-bioenergy-with-carbon-capture.pdf.

[64] T. Roulstone and P. Cosgrove, "UK energy systems for zero-carbon in 2050," *Nucl. Futur.*, vol. *18*, pp. 54–58, (2022).

[65] "Hydrogen Production Costs 2021," BEIS (Department for Business, Energy and Industrial Strategy), (2021). Online: https://assets.publishing.service.gov.uk/media/611b710e8fa8f53dc994e59d/Hydrogen_Production_Costs_2021.pdf.

[66] "UK Natural Gas," Trading Economics. Online: https://tradingeconomics.com/commodity/uk-natural-gas.

[67] D. Mullen, L. Herraiz, J. Gibbins, and M. Lucquiaud, "On the cost of zero carbon hydrogen: A techno-economic analysis of steam methane reforming with carbon capture and storage," Int. J. *Greenh. Gas Control*, vol. **126**, no. May, p. 103904, (2023). DOI: 10.1016/j.ijggc.2023.103904.

[68] R. W. Howarth and M. Z. Jacobson, "How green is blue hydrogen?," *Energy Sci. Eng.*, vol. **9**, no. 10, pp. 1676–1687, (2021). DOI: 10.1002/ese3.956.

[69] M. C. Romano et al., "Comment on 'How green is blue hydrogen?,'" *Energy Sci. Eng.*, vol. *10*, no. 7, pp. 1944–1954, (2022). DOI: 10.1002/ese3.1126.

[70] B. Parkinson, P. Balcombe, J. F. Speirs, A. D. Hawkes, and K. Hellgardt, "Levelized cost of CO2 mitigation from hydrogen production routes," *Energy Environ. Sci.*, vol. *12*, pp. 19–40, (2019). DOI: 10.1039/c8ee02079e.

[71] A. Pandiyan, A. Uthayakumar, R. Subrayan, S. W. Cha, and S. B. K. Moorthy, "Review of solid oxide electrolysis cells: A clean energy strategy for hydrogen generation," *Nanomater. Energy*, vol. *8*, no. 1, (2019). DOI: 10.1680/jnaen.18.00009.

[72] A. Hauch et al., "Recent advances in solid oxide cell technology for electrolysis," *Science (80-. ).*, vol. **370**, (2020). DOI: 10.1126/science.aba6118.

[73] "Unlocking the Power of Heat to Maximize Clean Hydrogen Production through Electrolysis," Bloom Energy, (2021). Online: https://www.bloomenergy.com/bloomelectrolyzer/#download.

[74] P. Caldwell et al., "Electrolysis Teach-in," Ceres Power, (2021). Online: https://wp-ceres-2022.s3.eu-west-2.amazonaws.com/media/2021/07/SOEC-Teach-in_FINAL-.pdf.

[75] B. S. Pivovar, M. F. Ruth, D. J. Myers, and H. N. Dinh, "Hydrogen: Targeting $1/kg in 1 Decade," *Electrochem. Soc. Interface*, vol. *30*, no. 4, pp. 61–65, (2021). DOI: 10.1149/2.F15214IF.

[76] J. Aihara et al., "R&D on commercial high temperature gas-cooled reactor," in *High Temperature Gas-cooled Reactors*, INC, pp. 313–450, (2021). DOI: 10.1016/B978-0-12-821031-4.00005-1.

[77] M. Middleton, "Development of Thermochemical Hydrogen Production from Nuclear: Final Feasibility Report," NNL (National Nuclear Laboratory), (2022). Online: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1158081/HYS2115_NNL_Final_Feasibility_Report__Public_.pdf.

[78] M. Assiter, I. McDonald, H. Cathcart, and S. Mccluskey, "Low Carbon Hydrogen Supply 2 Competition Stream 1 Phase 1 Nuclear Hydrogen Cogeneration," Frazer-Nash, (2022). Online: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1158090/HYS2153_FNC_Final_Feasibility_Report__Public_.pdf.

[79] I. Hannula, N. Kaisalo, and P. Simell, "Preparation of Synthesis Gas from CO2 for Fischer–Tropsch Synthesis—Comparison of Alternative Process Configurations," *C—Journal Carbon Res.*, vol. **6**, no. 3, p. 55, (2020). DOI: 10.3390/c6030055.

[80] S. Yang, L. Zhang, and Z. Wang, "Advances in the preparation of light alkene from carbon dioxide by hydrogenation," *Fuel*, vol. **324**, no. PA, p. 124503, (2022). DOI: 10.1016/j.fuel.2022.124503.

[81] M. El-Shafie and S. Kambara, "Recent advances in ammonia synthesis technologies: Toward future zero carbon emissions," Int. J. *Hydrogen Energy*, vol. **48**, no. 30, pp. 11237–11273, (2023). DOI: 10.1016/j.ijhydene.2022.09.061.

[82] A. Al-Rumaihi, M. Shahbaz, G. Mckay, H. Mackey, and T. Al-Ansari, "A review of pyrolysis technologies and feedstock: A blending approach for plastic and biomass towards optimum biochar yield," *Renew. Sustain. Energy Rev.*, vol. **167**, no. May, p. 112715, (2022). DOI: 10.1016/j.rser.2022.112715.

[83] J. Robinson et al., "Unravelling the mechanisms of microwave pyrolysis of biomass," *Chem. Eng. J.*, vol. **430**, no. P3, p. 132975, (2022). DOI: 10.1016/j.cej.2021.132975.

[84] J. Luo et al., "Review of microwave pyrolysis of sludge to produce high quality biogas: Multi-perspectives process optimization and critical issues proposal," *Renew. Sustain. Energy Rev.*, vol. **173**, no. 3688, p. 113107, (2023). DOI: 10.1016/j.rser.2022.113107.

[85] A. Sodiq et al., "A review on progress made in direct air capture of CO2," *Environ. Technol. Innov.*, vol. **29**, p. 102991, (2023). DOI: 10.1016/j.eti.2022.102991.

[86] J. Young et al., "The cost of direct air capture and storage can be reduced via strategic deployment but is unlikely to fall below stated cost targets," *One Earth*, vol. **6**, no. 7, pp. 899–917, (2023). DOI: 10.1016/j.oneear.2023.06.004.

[87] "DAC and GGR Innovation Programme Project NNB202043: Heat-driven Direct Air Capture Powered by Nuclear Power Plant Phase 1 Final Report," NNB GenCo (Nuclear New Build Generation Company), (2022). Online: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1075301/nnb-generation-nnb202043-phase-1-report.pdf.

[88] A. Al-Othman, N. N. Darwish, M. Qasim, M. Tawalbeh, N. A. Darwish, and N. Hilal, "Nuclear desalination: A state-of-the-art review," *Desalination*, vol. **457**, no. January, pp. 39–61, (2019). DOI: 10.1016/j.desal.2019.01.002.

[89] X. Xu, G. Dehghani, J. Ning, and P. Li, "Basic properties of eutectic chloride salts NaCl-KCl-ZnCl2 and NaCl-KCl-MgCl2 as HTFs and thermal storage media measured using simultaneous DSC-TGA," *Sol. Energy*, vol. **162**, no. January, pp. 431–441, (2018). DOI: 10.1016/j.solener.2018.01.067.

# Contact


## Authors

Juan Matthews **juan.matthews@manchester.ac.uk**
William Bodel **william.bodel@manchester.ac.uk**
Gregg Butler **gregg.butler@manchester.ac.uk**

## Director

Zara Hodgson **zara.hodgson@manchester.ac.uk**

## General enquiries

Email: dalton@manchester.ac.uk

**www.manchester.ac.uk/dalton**

**Dalton Nuclear Institute**
The University of Manchester
1st Floor Oddfellows Hall
Grosvenor Street
Manchester
M1 7HF


The Dalton Nuclear Policy Group offers advice and recommendations to policy-makers and other stakeholders, founded on impartial and evidence-based analysis. Find all our policy papers at:
**www.manchester.ac.uk/dalton-policy**



Royal Charter Number RC000797 | DW3904.10.24