Renewable Energy 205 (2023) 256–272

Contents lists available at ScienceDirect

Renewable Energy

journal homepage: www.elsevier.com/locate/renene

# The effect of a nuclear baseload in a zero-carbon electricity system: An analysis for the UK

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ARTICLE INFO

*Keywords:*
Nuclear baseload
Small modular reactors
Energy storage capacity
Renewable mix
Grid flexibility
Levelized cost electricity

ABSTRACT

This paper explores the effect of having a nuclear baseload in a 100% carbon-free electricity system The study analyses numerous scenarios based on different penetrations of conventional nuclear, wind and solar PV power, different levels of overgeneration and different combinations between medium and long duration energy stores (hydrogen and compressed air, respectively) to determine the configuration that achieves the lowest total cost of electricity (TCoE).

At their current cost, new baseload nuclear power plants are too expensive. Results indicate the TCoE is minimised when demand is supplied entirely by renewables with no contribution from conventional nuclear.

However, small modular reactors may achieve costs of ~£60/MWh (1.5× current wind cost) in the future. With such costs, supplying ~80% of the country's electricity demand with nuclear power could minimise the TCoE. In this scenario, wind provides the remaining 20% plus a small percentage of overgeneration (~2.5%). Hydrogen in underground caverns provides ~30.5 TWh (81 days) of long-duration energy storage while CAES systems provide 2.8 TWh (~8 days) of medium-duration storage. This configuration achieves costs of ~65.8 £/MWh. Batteries (required for short duration imbalances) are not included in the figure. The TCoE achieved will be higher once short duration storage is accounted for.

## 1. Introduction

During the past few years, wind and solar PV power have been the fastest growing forms of renewable generation [1]. These forms of renewable generation have achieved costs lower than those of the cheapest new fossil-fuelled plants [2] and are likely to provide most of the world's renewable electricity in the future.

Several countries around the globe have made considerable progress replacing fossil fuel generation with renewable energy. In 2020 Denmark produced 63% of its electricity from wind and solar, followed by Uruguay (43%) Ireland (38%), Germany (33%) and Greece (32%). In the UK, wind and solar generated about 28% of the country's demand [3]. The shift to a renewable-based electricity system brings new challenges as renewable generation (wind and solar PV) not only is intermittent and has considerable inter-annual variations, but it is also inflexible.

To function correctly, electricity grids require a balance between energy generation and consumption [4]. Presently, fossil-fuelled power plants provide the necessary flexibility to balance changes in demand. The output of these conventional power plants (coal of gas-fired) can be controlled according to how much energy is required. Fossil-fuelled power plants also provide the grid with some inertia to overcome short energy imbalances.

The amount of energy produced by a wind or solar farm is determined by the availability of the natural resource and cannot be turned up to match a sudden increase in demand. Therefore, as more fossil-fuelled power plants are replaced by renewable generation, the grid loses flexibility and the challenge of matching electricity supply and demand becomes increasingly difficult. Not being able to provide additional flexibility to the electricity grid could halt the deployment of more renewable energy [5].

Another form of clean electricity generation is nuclear power. Nuclear has received renewed and increased interest in the UK, mainly to the urgency of the country to eliminate its dependence on Russian gas because of the war in Ukraine [6].

Although nuclear power in the UK has been submerged in controversy due to the high costs and numerous problems in the construction of Hinkley Pont C, the only conventional nuclear power plant currently under development in the country [7], the British government has put nuclear power at the centre of its new energy security strategy [8]. The plan is for nuclear power to deliver ~25% of the country's projected

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https://doi.org/10.1016/j.renene.2023.01.028
Received 16 September 2022; Received in revised form 15 November 2022; Accepted 6 January 2023
Available online 24 January 2023
0960-1481/

**Nomenclature**

*Acronyms*

| | |
|---|---|
| CAES | Compressed air energy storage |
| CSP | Concentrated solar power |
| *LCoE* | Levelized cost of electricity (£/MWh) |
| ORC | Organic Rankine cycle |
| PHES | Pumped hydro energy storage |
| *TCoE* | Total cost of electricity |
| TES | Thermal energy storage |

*Greek Letters*

| | |
|---|---|
| $\alpha$ | Cost per unit capacity of an energy store (£/KWh) |
| $B$ | Cost per unit power of charging machinery (£/kW) |
| $\gamma$ | Cost per unit power of discharging machinery(£/kW) |
| $\eta$ | Roundtrip storage efficiency |
| $\lambda$ | Useful life of energy store (years) |
| $\tau$ | Number of years considered in analysis |
| $\Omega$ | Allowable over-generation (as a fraction of energy demand) |

| | |
|---|---|
| $C_n$ | Total cost of energy produced from nuclear power (£) |
| $C_{store}$ | Capex of an energy store (£) |
| $C_s$ | Total cost of energy produced from solar PV (£) |
| $C_w$ | Total cost of energy produced from wind power (£) |
| $D_{net}$ | Profile of net demand (kW) |
| $E_D$ | Total energy demand over period analysed (kWh) |
| $E_{need}$ | Amount of energy required from renewables (includes overgeneration and losses) (kWh) |
| $E_{neg}$ | Energy contained in the negative part of profile of net demand (kWh) |
| $E_{pos}$ | Energy contained in the positive part of profile of net demand (kWh) |
| $L$ | Energy losses (kWh) |
| $N$ | Penetration of nuclear (baseload) power |
| $P_c$ | Rated charging power of energy store (kW) |
| $P_d$ | Rated discharging power of energy store (kW) |
| $R$ | Ratio indicating mix between wind and solar |
| *Size* | Capacity of energy store |
| $X$ | Ratio indicating mix between energy stores ($H_2$ and CAES) |

electricity demand by 2050 [9]. Conventional nuclear power provides a constant energy output, so many consider it ideal to supply a baseload. However, like renewables, this output is inflexible. Replacing fossil-fuelled generation with conventional nuclear power stations will also bring grid balancing challenges.

There is the possibility of coupling nuclear plants with thermal energy storage so that their output is (at least partially) dispatchable. In other words, the direct integration with thermal storage turns inflexible baseload plants into flexible or 'load-following' plants (i.e. electricity is generated when it is needed). Having thermal storage alongside nuclear also enables to integrate these plants into broader energy systems, such as district heating networks. Relevant research carried out in this field can be found in Refs. [10–17].

If the costs of renewable generation were low enough, the balancing problem of a 100% carbon-free electricity grid could be solved simply by oversizing the country's renewable generation capacity so that demand is fully met always, even during peak periods or during times of low generation. This approach entails an enormous amount of energy curtailment during periods of low demand. The same could be done with conventional nuclear power, albeit to a lesser extent as nuclear plants have a minimum power output. Current costs of nuclear and renewable generation render this theoretical solution as completely unfeasible.

Energy storage offers a realistic, achievable solution to the grid balancing problem. An energy store takes electricity from the grid at times of excess generation and stores it. Then, at times of peak demand and/or low generation, electricity is put back into the grid. In this way energy storage technologies enhance the flexibility of the electricity grid and rectify the disparity between the profiles of generation and demand [18]. As the contribution of renewables or baseload nuclear to the total electricity demand increases, a greater energy storage capacity will be required to balance the system [19].

In future zero-carbon electricity grids, a broad range of storage durations going from fractions of a second up to several months will be required. Here, storage duration refers to the length of time over which a particular energy store can provide electricity at its rated discharge power. No single energy storage technology can deal with the entire spectrum. The range of storage durations (i.e. discharge times) can be divided into four main categories [20].

1) *very-short duration storage* (<5 min). Currently this is provided by the rotating inertia of traditional power plants. In the future this will arguably be handled best by flywheels [21].
2) *short-duration storage* (5 min–4 h) which is served best by Li-ion batteries [22].
3) *medium-duration storage* (4–200 h) where pumped-hydro [23] and thermo-mechanical solutions [24] such as compressed air energy storage [25], liquid air energy storage [26] and pumped thermal energy storage [27] comprise the main options
4) *long-duration storage* (>200 h) which deals with the inter-annual variability of renewables and will require by far the largest storage capacity. This can only be achieved by storing fuels such as hydrogen in underground caverns [28,29]. A vast amount of research effort has been aimed at quantifying the energy storage capacity that will be required to achieve 100% carbon free electricity systems. References [30–36] are examples of this line of work.

There seems to be a general agreement on two main points.

A) The requirement for energy storage capacity reduces as the match between the profiles of electricity generation and demand improves. This can be accomplished by tuning the mix of generation sources or by implementing demand side management strategies.
B) Electricity over-generation helps to reduce the time-mismatch between electricity generation and demand and consequently the requirement for energy storage. This is a trade-off between the value of the curtailed electricity and the cost of storage. Allowing a small amount of over-generation (and curtailment) in the system can lead to a lower overall electricity cost by reducing cost of storage However, a large amount of curtailment will overshadow savings and lead to an increased cost of electricity due to the increased cost of generation.

### 1.1. Previous work

In a previous study, Cardenas et al. quantified how much energy storage capacity the UK will need to achieve a renewable penetration of 100% and assessed what is the best way to provide the required storage capacity at the lowest system cost [37]. The study used many years of historical generation and demand data and explored several different mixes between wind and solar, various levels of over-generation and different combinations of storage technologies.

It was found that the optimum mix of renewables for the country is 85% wind and 15% solar. With this generation mix and considering current levels of electricity demand, ~66.6 TWh of storage capacity are needed and an overall system cost of ~75.6 £/MWh can be achieved. These results consider 15% of over-generation. In the cost-optimal scenario, hydrogen provides 55.3 TWh of storage, CAES provides 11.1 TWh and the remaining 170 GWh are supplied by Li-ion batteries. The study also revealed that more than 60% of all the energy emerging from storage comes from the medium duration stores.

In the previous study hydrogen was considered for the long-duration (or bulk) energy storage duty as it is very cheap per kWh but it is not ideal for frequent charging/discharging due to its low roundtrip efficiency. Compressed air was considered for the medium-duration role [38,39] as it has a better efficiency and cheaper cost per unit power than hydrogen, but it is more costly per unit storage capacity. Batteries are ideal to deal with short-duration imbalances in the grid as they have faster response times and raping capabilities than $H_2$ and CAES but also higher efficiencies [40]. However, batteries have a considerably high cost per unit storage capacity. Therefore, their total installed capacity is small compared to the other two technologies. Very-short duration storage was not included in the study due to the lack of historical data with a fine resolution.

The study did not include nuclear power as part of the energy mix. Wind power has achieved levelized costs that are less than half the current costs of conventional nuclear generation in the UK [41]. Hinkley point C has a cost of 92.5 £/MWh at a capacity factor of 91% [42]. Lazard's analysis of levelized costs estimates the cost of nuclear to be even higher at a minimum of 114 £/MWh [43]. Child et al. [33] comment that nuclear power has seen steady increases in its levelized cost of electricity over the past decades. This is due to ever higher capital expenditures that result from increasing system complexity, high budget and construction time overruns, and a need to protect society from the dangers of nuclear accidents and threats of terrorism. For these reasons, the previous study considered conventional nuclear power to have a limited scope to play a significant role in a future net-zero electricity system in the UK.

### *1.2. Objectives and contribution*

This paper explores the effects of having conventional (baseload) nuclear generation as part of the energy mix in a 100% carbon-free electricity system. Using historical demand and generation data for the UK, this study evaluates numerous system configurations or 'scenarios' based on different generation mixes (conventional nuclear, wind and solar PV), over-generation levels, and combinations of energy storage technologies.

The study seeks to determine what is the optimum mix of generation (nuclear, wind and solar PV) and storage technologies that leads to the lowest total cost of electricity (*TCoE*) for a 100% carbon-free system and whether there is an economic case to build new conventional nuclear power plants in the UK.

A small amount of the overall energy demand could be supplied by a flexible source such as biomass. The flexibility this provides would help to reduce the total energy storage capacity needed. However, the contribution of biomass to the energy mix will not be significant in the future (<10%) and it is therefore not included in this study. Through this paper, we seek to provide some guidance to policy makers in the country regarding what is the best route—from an economic standpoint—towards a 100% carbon-free electricity supply. Although the study considers the UK as a reference case, the methodology followed is well described and could easily be applied to other territories.

It is important to note that conventional nuclear power is particularly expensive in the UK compared with other generation technologies, while in other countries such as South Korea it is considerably cheaper [44]. This study does not seek to discredit nuclear power nor it seeks to discourage new research on next generation reactors or flexible 'load-following' plants. The paper also does not advocate against refurbishing existing nuclear assets in the country that are coming to the end of their service life.

## 2. Historical electricity demand and generation data

This study is based on electricity demand and renewable generation (wind and solar-PV) data from the UK. The historical data was obtained from the '*Balancing Mechanism Reporting Service*', which is the main source of operational data relating to the electricity grid of the country.

Fig. 1a shows the profile of electricity consumption in the UK between 2011 and 2019. The data has been normalised on an annual basis. The country consumed ~335 TWh of electricity during 2019 [45]. Subsequent years are not representative due to the disruption caused by Covid-19. Historically, the maximum load experienced by the grid at any one time is ~60 GW whilst the average load fluctuates around 38 GW. It can also be seen in Fig. 1a that the demand for electricity increases during winter, although natural gas supplies most of the heating demand [46].

Fig. 1b shows the profile of wind power generation in the country during the same 9-year period. The data has been normalised to account for the increase in installed capacity over the years. The profile clearly

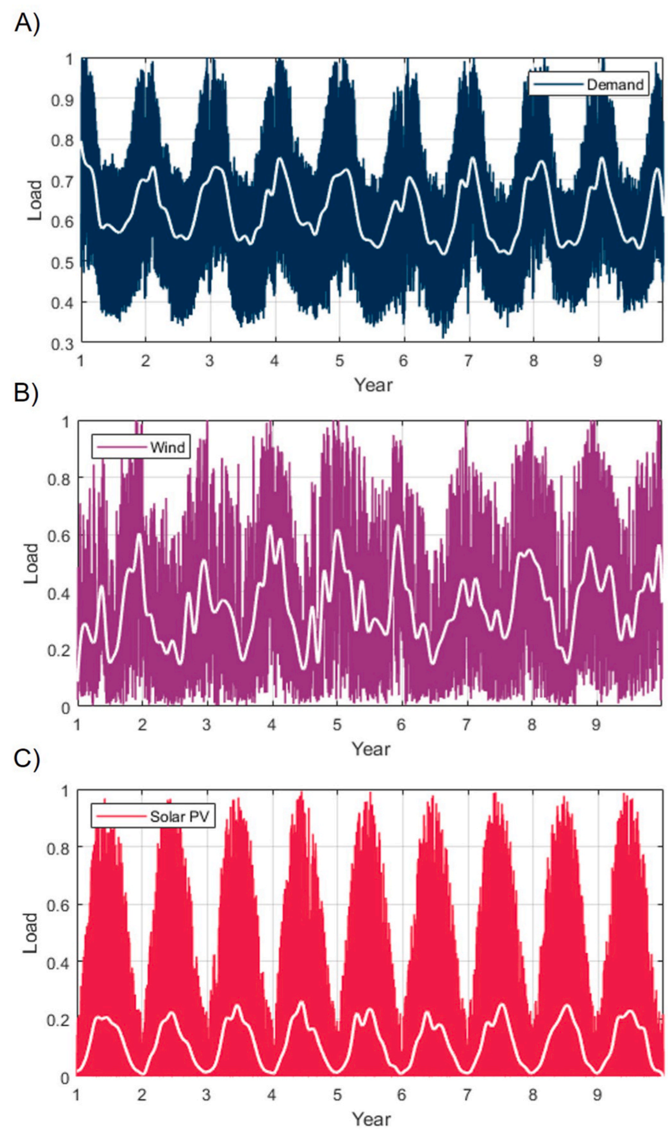


**Fig. 1.** Normalised profiles containing 9-years of UK data: A) electricity demand [47,48] B) Wind power generation [47,48] C) Solar-PV power generation [49,50].

shows the strong season and inter-annual variability of the wind resource. There are also marked daily variations [51,52]. In general, wind turbines generate more electricity during the colder months of the year as wind speeds are faster during winter [53]. During the 9 years shown in the figure, >60% of the electricity was generated during the colder months (Oct–Mar). Wind power is well suited to supply most of the country's electricity as its seasonal behaviour largely resembles that of demand.

Lastly, Fig. 1c shows a profile of solar-PV generation in the UK for the same 9-year period. In this case, historical (measured) solar irradiation data was used to estimate the power output of a 1 KW solar panel [49,50]. It can easily be seen that solar-PV power in the UK has an even stronger seasonal component than wind power. Approximately 80% of the energy generated during the 9-year period considered was produced between the months of April and September.

This study uses several years of data to capture the inter-annual behaviour of the renewable resources. Although the seasonal variability of renewable generation and electricity demand is captured in a single year of data, failing to account for the inter-annual variability of wind and solar can lead to a considerable underestimation of the energy storage capacity required [54]. Ideally, studies of this kind should use as long a period as possible to ensure that years with a particularly poor availability of renewable resources are captured. We found older data to be unreliable thus we are limited to a 9-year period.

## 3. Methodology

This study follows a similar procedure to that used previously in Ref. [37]. As mentioned, this study aims to understands the effect of having a certain contribution of conventional nuclear power generation in the energy mix.

In this investigation, a full factorial experiment is carried out using four '*system configuration*' variables: the contribution of baseload nuclear power to the energy mix (***N***), the mix of renewables (***R***), the percentage of overgeneration ($\boldsymbol{\Omega}$) and the mix of energy stores (***X***).

The study focuses on conventional inflexible nuclear plants. For a given value of ***N***, a constant nuclear baseload at a certain power level is modelled. Research has been carried out on integrating nuclear plants with thermal storage to turn them into 'load following' rather than baseload [10–17]. This is a promising solution that can increase the functionality and potential benefits of nuclear power. It can also enable nuclear plants to supply heat for other applications and integrate into broader energy systems. Existing conventional nuclear plants could also be retrofitted with thermal storage as part of refurbishment plans to increase their service life. This concept—albeit promising—is still at early stages of research and is thus not included in this paper. Nevertheless, research should continue to be carried out to further develop it.

The mix of renewables (***R***)is expressed as a ratio between 0 and 1. This represents the fraction of all renewable energy (1-***N***) that is generated by wind turbines. The fraction produced by solar PV panels is simply 1-***R***.

The energy storage mix (***X***)is also expressed as a ratio between 0 and 1. Energy storage will always be required in a zero-carbon system. The storage capacity required depends on how well the profile of generation matches that of demand, which in turn depends on the mix between variable renewables and nuclear. The ratio (***X***) indicates what fraction of all the energy that needs to pass through storage will be stored in the 'medium duration' store. The fraction of the energy that will be stored in the 'long duration' store is given by 1-***X***.

In this study we use CAES as a representative technology for medium duration energy storage and hydrogen in underground caverns as the representative technology for long duration energy storage. In terms of capacity, medium and long duration storage technologies will provide the vast majority of all the storage capacity that the country will need [28]. Both technologies are technically capable of providing all of the energy storage capacity needed; however, that would lead to an expensive solution. A mix between the two technologies enables to exploit their attributes best and achieve a lower cost of electricity.

Hydrogen has a very low cost per energy storage capacity but it has a high cost per unit power. Electrolysers are used during the 'charging' phase and they are still expensive. Therefore hydrogen production and storage is very well suited for long duration energy storage, where an enormous storage capacity is needed but energy is charged and discharged at a slow rate.

A medium duration store will have a smaller capacity but will have higher charge/discharge powers. CAES is very well suited for this role (as opposed to $H_2$) because although its cost per unit capacity is higher than $H_2$, its cost per unit power is lower. Pumped hydro (PHES) is one of the most efficient and cheapest forms of bulk energy storage that is also perfectly suitable for the medium duration role. The UK already has a storage capacity of ~27.6 GWh thanks to its PHES plants in Wales and Scotland [55]. There are plans in place to build a new 30 GWh PHES plant in Coire Glas (Scotland) by 2030, which will more than double the current installed capacity [56]. A study by Stocks et al. [57] shows that the UK has the potential for approx. ~6 TWh of pumped hydro storage. However only ~1.8 TWh of this consists of large scale installations (50–150 GWh) which have the best economics. The rest comprises sites with a potential capacity between 2 and 15 GWh, which generally do not achieve the same attractive economics as larger sites. Considering this, the authors believe that pumped hydro has a limited potential to contribute significantly to the total energy storage capacity in the country (although it should be exploited as much as possible). This paper does not include PHES in the calculations; however, this simplification does not significantly affect the *TCoE* figures presented.

Li-ion batteries are not considered in the study because determining their duty cycles requires the use of data with a resolution <5 min, which is too computationally expensive for the scope of this work. Nevertheless, the authors recognise and stress that Li-ion batteries are required to deal with short-duration but frequent imbalances in the grid due to their high efficiencies and fast response times [39,58]. Batteries will accumulate very small amounts of energy in comparison to the medium and long duration energy stores (CAES and $H_2$, respectively), but they will see a proportionally large energy throughput. The cost structure of Li-ion batteries positions them well for daily cycling applications, where their high energy capital cost can be paid for by frequent cycling [38]. Batteries are a good option for short-duration (high-frequency) energy storage because they have very fast response times and a low cost per unit rated (dis)charge power.

The general trends presented in this paper are not affected by the omission of Li-ion; however the overall system costs seen can be up to ~6 £/MWh lower than what they would otherwise be. This does not interfere with the main research questions which are: *i)* what is the effect on the overall system of having a nuclear baseload? and *ii)* what is the optimum contribution from conventional nuclear power to the energy mix?

The study looks at several different system configurations or scenarios. Each one of these is defined by the four variables mentioned earlier: ***N***,***R***,$\boldsymbol{\Omega}$ and ***X***. Fig. 2 shows in the form of a flow chart the process followed for modelling a specific scenario or system configuration. For a given scenario, the calculation process begins by amplifying the normalised profile of electricity demand to have an average annual demand of ~335 TWh. This aligns with pre-pandemic consumption levels.

The profile of nuclear generation is constant at a certain power level (i.e. baseload generation). This power level is calculated through Eq. (1), so that the energy produced over the period analysed corresponds to the specified nuclear penetration (***N***). In Eq. (1), the divisor represents the number of hours in the 9-year period analysed.

$$Nuclear\ Power = \frac{(335\ TWh \bullet 9\ years) \bullet N}{78840} \tag{1}$$

The profile of nuclear baseload is subtracted from the profile of demand to create an intermediate profile of 'remaining demand'.

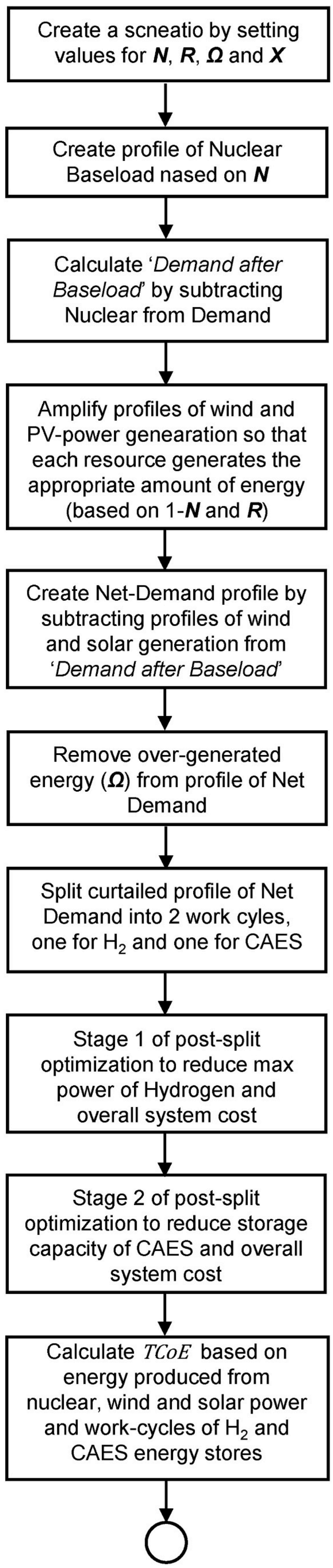


**Fig. 2.** Algorithm followed to calculate the total cost of electricity achieved by a specific system configuration.

Renewables will provide the energy contained in this 'remaining demand' profile.

However, determining how much energy the renewable resources need to generate is an iterative calculation. The renewables' output is amped up to compensate for storage losses, which in turn affects the amount of energy that will pass through storage and consequently the magnitude of the energy losses. The iteration starts by estimating how much renewable energy is needed ($E_{need}$). This is done by means of Eq. (2) where $E_D$ is the total energy demand over the period analysed and $L$ are the total storage losses. The first guess for $L$ takes a value of zero. It is important to clarify that $\boldsymbol{\Omega}$ is a fraction of total energy demand and not of '*demand after baseload*'.

$$E_{need} = (E_D * (N - 1)) + (E_D * \Omega) + L \tag{2}$$

The normalised profiles of wind and solar generation are multiplied by a factor $f$ so that the energy that each resource produces over the 9-year period corresponds to the defined value of $\boldsymbol{R}$. The profile of net-demand ($D_{net}$) is created by subtracting the amplified wind and solar profiles from the 'demand after baseload' profile.

The negative part of the net demand profile ($E_{neg}$) includes the energy that will be put into storage as well as the over-generated energy that will be curtailed. The positive side of the profile ($E_{pos}$) is the energy that the store will discharge back into the grid.

The iterative loop concludes when the condition expressed in Eq. (3) is met, where $\eta_{combined}$ is the combined efficiency of the two types of energy stores. At this point, the amount of renewable energy that is required to meet the remainder of demand ($E_D \bullet (1 - N)$) and to compensate for any storage losses has been calculated and the profile of net demand is now known.

$$abs(E_{neg}) - (E_D * \Omega) = \frac{E_{pos}}{\eta_{combined}} \tag{3}$$

The following step is to remove the over-generated energy, which is still embedded in the negative part of the net-demand profile. A time-stepping algorithm is used for this. The algorithm, described in Ref. [19], models the state of charge of a single energy store throughout the complete work-cycle. This is an iterative loop that begins with a guess for the capacity of the store.

If the capacity ('*size*') of the store is too small there will be excessive curtailment and the size of store is revised. This iterative loop concludes when the amount of curtailment at the end of the work-cycle corresponds to the specified value of $\boldsymbol{\Omega}$. Curtailing energy when it is necessary, rather than at prescribed times, allows to see the full benefit of overgeneration in terms of minimising the energy storage capacity required in the system.

We proceed to split the curtailed profile of net demand into two separate work-profiles for the $H_2$ and CAES stores. A signal-processing tool known as a 'Sign-Preserving Filter' is used for this. The filter takes the $D_{net}$ profile and splits it into two work-cycles, one is assigned to the hydrogen store whilst the other is assigned to CAES. The key feature of the Sign-Preserving Filter is that the two output profiles always have the same sign as the net demand profile. This avoids counterflow of energy (i.e. charging one store with the other) and oversizing the overall storage capacity.. A detailed explanation of the mechanics of the filter's operation is provided in Ref. [59].

The profiles produced by the filter are processed by two 'post-split' optimisation functions to achieve a lower overall system cost. The first of these functions focuses on reducing power peaks in the hydrogen's work-profile and replacing those with CAES, as it has a lower cost per kW than $H_2$ (see Table 1). It is important to highlight that these modifications to the profiles are done without breaking the condition of sing preservation. The two profiles still have the same sign as the original $D_{net}$ profile at all times and the sum of the two profiles still replicates exactly the original $D_{net}$ profile..

The second post-split optimisation function concentrates on

**Table 1**
Figures used for the calculation of the *TCoE*.

| | Value | Ref. |
|---|---|---|
| LCOE of Conventional Nuclear Power | 92.5 £/MWh | [72] |
| LCOE of Wind | 40 £/MWh | [73,74] |
| LCOE of Solar PV | 60 £/MWh | [75,76] |
| CAES storage capacity cost ($\alpha$) | 3.5£/kWh | [77,78] |
| CAES charging power cost ($\beta$) | 300 £/kW | [77,78] |
| CAES discharge power cost ($\gamma$) | 300 £/kW | [77,78] |
| CAES roundtrip efficiency | 70% | [24,69] |
| $H_2$ storage capacity cost ($\alpha$) | 0.67 £/kWh | [79] |
| $H_2$ charging power cost ($\beta$) | 1100 £/kW | [80] |
| $H_2$ discharge power cost ($\gamma$) | 450£/kW | [81,82] |
| $H_2$ roundtrip efficiency | 45% | [67,68] |
| Lifetime of CAES ($\lambda$) | 30 Years | [83,84] |
| Lifetime of $H_2$ ($\lambda$) | 30 Years | [40,84] |

replacing some of the overall storage capacity of CAES with $H_2$, as the latter has a lower cost per kWh (see Table 1).. A more detailed explanation of the 'post-split' optimisation functions can be found in Ref. [37].

The study assumes that generation is not directly coupled with storage, which is true for current technologies. Here, renewables and conventional nuclear power plants produce electricity first and the portion of generation that exceeds demand is sent to storage. For high levels of nuclear a fraction of the baseload is also sent to storage because it exceeds demand at times. This will be discussed in more detail in section 4.2.

The concept of 'Generation integrated energy storage' has been discussed by Garvey et al. [60]. It suggests storing the primary energy in the form it was generated (e.g. heat) and only convert it to electricity, when electricity is needed and not before. This minimises the number of transformations and will yield a higher overall efficiency. Currently only 'Concentrated Solar Power' (CSP) plants work in this way. However there are a number of concepts for coupling wind turbines [61,62] and nuclear plants [10–17] with heat storage. These are promising concepts that should be further investigated. Despite the many potential advantages, this study does not consider them in the calculations as there are no systems built and there is no sufficient information regarding their costs available in the literature.

As mentioned, Li-ion batteries are not considered in this study for practical reasons. Determining their duty requires data with a <5min resolution, which makes the analysis too computationally expensive for the 9-year period analysed. If the work profile of batteries were to be determined for any given scenario (combination of $\boldsymbol{N}$,$\boldsymbol{R}$,$\boldsymbol{X}$ and $\boldsymbol{\Omega}$) a 'ramp-rate function' could be used The power conversion equipment used for charging and discharging the hydrogen and CAES stores does not have the capability of ramping as fast as the work profiles dictate. This machinery has real ramping rates of ~5% of the max. Power per minute [63,64].

The ramp-rate function would receive both work cycle ($H_2$ and CAES) and determine all the points in time in which the stores are not capable of following their work cycle. The work cycle for batteries is then composed by the shortcomings of $H_2$ and CAES. In this way the fast and slow response needs of the system would be covered. The capacities and powers of the medium and long duration stores will not change significantly once batteries are accounted for in the model, as batteries will have a small capacity in comparison (several GWh compared to several TWh). However, as batteries have a high cost per unit capacity, the total cost of electricity (*TCoE*) could be ~6 £/MWh higher than what is reported in this paper.

Fig. 3 shows an example of a profile of net demand (after over generation is removed) for the scenario defined by $\boldsymbol{N} = 0.16$, $\boldsymbol{R} = 0.9$, $\boldsymbol{X} = 0.33$ and $\boldsymbol{\Omega} = 0.05$. Fig. 3b and c shows the work-cycles for CAES and hydrogen after net demand has been passed through the filter and post-optimisation functions. The sum of the CAES and $H_2$ profiles replicates exactly the profile of net demand.

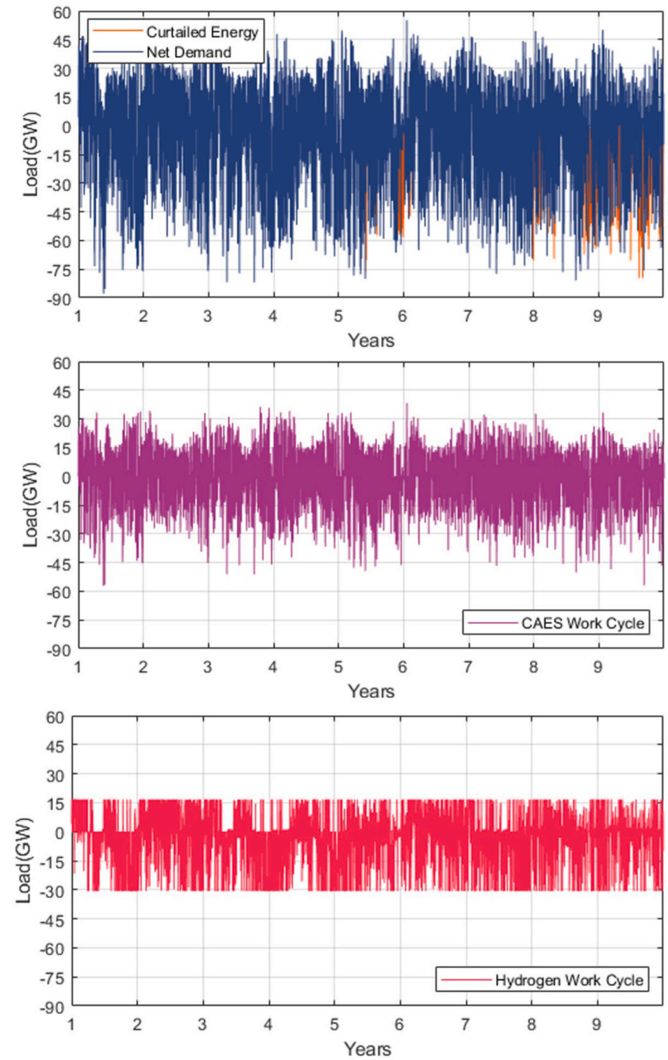


**Fig. 3.** Example of profile of net demand and work cycles for the medium (CAES) and long-duration ($H_2$) stores. This scenario considers $\boldsymbol{N} = 0.16$, $\boldsymbol{R} = 0.9$, $\boldsymbol{X} = 0.33$ and $\boldsymbol{\Omega} = 0.05$.

At this point, the scenario defined by the four variables $\boldsymbol{N}$,$\boldsymbol{R}$,$\boldsymbol{\Omega}$ and $\boldsymbol{X}$ has been modelled and we have all the information required to calculate the 'total cost of electricity' (*TCoE*) or 'total system cost'. The *TCoE* is a metric that represents the total average cost of producing and storing a unit of electricity. In this study, the calculation of the *TCoE* includes the cost of generating electricity and the capital expenditure related to the energy storage provisions (capacity and power), but it does not include transmission and distribution costs.

The cost of generating electricity is given by the levelized costs of conventional nuclear, wind and solar-PV power. The levelized cost of electricity (*LCoE*) is a lifetime cost that encompasses capital cost, load factors, efficiencies, operation costs, and other expenses associated with the generation of electricity.

The total cost of the energy produced from nuclear power ($C_N$)can be easily calculated via Eq. (4), where $E_D$ is the energy demand over the 9-year period analysed, and $LCoE_N$ is the levelized cost of conventional nuclear generation

$$C_N = (E_D * N) \bullet LCoE_N \tag{4}$$

From Eq. (2) we know how much energy is produced by the renewables ($E_{need}$). This includes the necessary amount to meet the remainder of demand after nuclear baseload and additional amount for loss-compensation and intentional curtailment. The total cost of the energy produced from wind ($C_W$) and solar-PV power ($C_S$) can be calculated via Eqs. (5) and (6)

$$C_W = E_{need} \bullet R \bullet LCoE_W \tag{5}$$

$$C_S = E_{need} \bullet (1 - R) \bullet LCoE_S \tag{6}$$

The capital cost of an energy store ($C_{store}$) can be calculated by means of Eq. (7). For many of the technologies that are well suited for medium and long-duration energy storage (CAES, LAES, pumped thermal, PHES, $H_2$ storage, etc.) the storage costs comprise an energy cost and a power cost. In most cases these two costs are independent of each other. In a CAES system for example, there is the cost of the underground salt cavern used to store air (energy cost) and the cost of the compressors and turbines used to charge and discharge the system (power cost). In Eq. (7), $\alpha$ is the cost per unit of storage capacity (£/kWh) of the particular technology, $\beta$ is the cost per unit power of the charging machinery (£/kW) and $\gamma$ is the cost per unit power of the discharging equipment (£/kW).

$$C_{store} = \alpha \bullet Size + \beta \bullet abs(P_c) + \gamma \bullet P_d \tag{7}$$

The capacity or '*size*' of the energy store is determined by integrating its work-profile and calculating the difference between the maximum and minimum points of the curve of accumulated energy over time. The discharge power ($P_d$) is the maximum value of the positive part of the work-profile whilst the charging power ($P_c$) is the minimum value of the negative part of the work-profile.

The system's *TCoE* is calculated through Eq. (8). Here $E_D$ is the total electricity demand over the 9-year period (3015 TWh), $C_W$ is the total cost of the energy generated from wind while $C_S$ is the cost of the energy produced by solar panels.

The calculation of the *TCoE* considers a fraction of the capex of the stores that is proportional to the 9-year period ($\tau$) that is being analysed. In Eq. (8) $\lambda$ represents the useful life of the energy stores.

$$TCoE = \frac{C_N + Cw + Cs + C_{CAES} \bullet \left(\frac{\tau}{\lambda}\right) + C_{H2} \bullet \left(\frac{\tau}{\lambda}\right)}{E_D} \tag{8}$$

Th study treats the electricity grid as a single node and focuses on determining the amount of storage capacity required to balance the system. At its core, the analysis performs an 'energy balance' in which all energy that was generated (except for the small fraction that is intentionally curtailed) must be consumed over the period analysed. Some of this energy is consumed in real time, but a fraction is stored and used subsequently.

Profiles of demand, wind, and solar PV generation that aggregate data for the whole country are used. Therefore, the study does not look at regional differences in demand and generation in detail. In other words, the model does not 'see' if at a given point wind is being produced in Scotland but there are demand peaks in London. This simplified model is only ensuring that all the energy that is generated is consumed, and if it cannot be used at the time of generation (anywhere else in the country) then it is sent to storage.

Although the real system does need to maintain an energy balance, this simplification implies a perfect transmission system. In reality, there will be congestion issues and transmission losses in the grid. The optimum location of renewable generation assets as well as conventional nuclear power plants needs to be carefully studied to minimise losses; however, it is out of scope for this work. An improper distribution of the generation capacity and lack of sufficient and robust transmission would entail an increase in the energy storage capacity that is needed.

The model assumes that the storage capacity is produced by 2 large, centralised stores ($H_2$ and CAES). This is another important simplification/assumption worth clarifying. In the real system, the total storage capacity will be provided by an array of small units distributed throughout the country, which most likely will sit alongside generation sites to avoid unnecessary transmission losses. The problem of determining where to install *x* amount of generation and/or storage capacity is of great importance as it has implications to the total system cost, such as the capex of transmission lines or curtailment due to congestion in those lines and should be carefully investigated. However, the distribution of the different storage units has little effect on the total storage capacity that is required, which is one of the main concerns of this paper. Therefore, it is considered beyond the scope of this work. As mentioned, the analysis centres on calculating how much storage capacity is needed to balance the grid. The ancillary services that can be provided by either conventional nuclear plants or the different energy stores such as inertia, frequency response, reactive power [65,66] are not quantified in the calculation of the total cost of electricity.

Another point worth mentioning is the electrical interconnection with mainland Europe. As the grid is decarbonised, this interconnection will help reducing (to some degree) the storage capacity required by geographically smoothening the variability both sides, demand, and generation. The interconnection will also allow the UK to access some pumped hydro storage capacity (available in the Alps and Scandinavia), which is a very cheap form of energy storage. This study does not take the interconnection into account as any prediction of when and by what amount it will be expanded, as well as its cost, has a high degree of uncertainty. In this regard, the figures obtained from analysing the UK as an isolated system are conservative.

## 4. Analysis of results and discussion

### 4.1. Effect of varying mix of renewables and storage technologies for a certain penetration of conventional nuclear power

In a previous study, the authors explored what a future net-zero electricity grid could look like if all the demand for electricity were met by a combination of intermittent renewable generation and energy storage with no contribution from nuclear power [37]. The present study expands on previous work by including conventional nuclear power into the energy mix.

In this section we use a (arbitrarily defined) nuclear baseload of 16% of the total electricity demand to explain the effect that varying the other system parameters (***R*** and ***X***) has on cost-influencing parameters such as the energy storage capacity and the rated powers of the energy stores. As explained in section 3, for a given value of ***N*** one must determine the values for ***R***, ***Ω*** and ***X*** that yield the lowest system cost. The trends observed can be compared to results presented in Ref. [37] where a penetration of 0% nuclear is assumed.

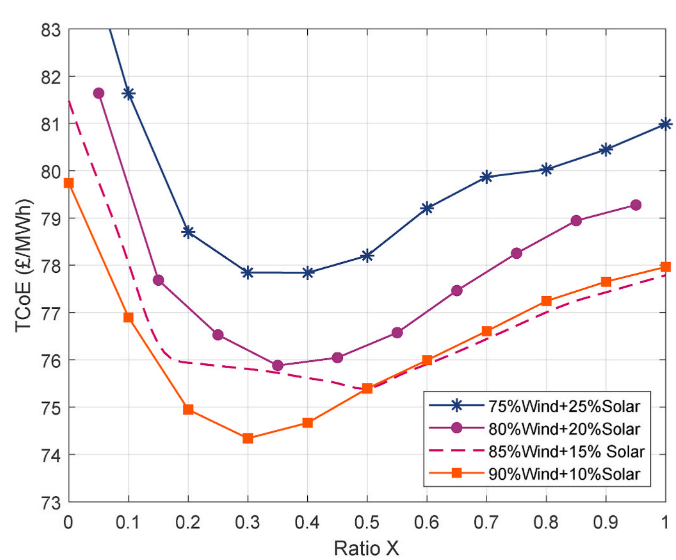


**Fig. 4.** Effect of different mixes of renewables and energy storage technologies on the total cost of electricity for a system considering a nuclear baseload of 16%.

Fig. 4 shows the effect of varying ***R*** and ***X*** for an ***N*** fixed at 0.16. Each one of the four curves plotted corresponds to a different value of ***R*** (0.75,0.8, 0.85 and 0.9). Each of the data points along the curves represents a specific scenario in which the amount of overgeneration ($\boldsymbol{\Omega}$) considered is the optimum for that particular combination of ***N***, ***R*** and ***X***. The performance and economic figures used for calculating the total cost of electricity are given in Table 1.

Increasing the fraction of the total renewable energy that is provided by wind leads to a reduction in the overall system cost or total cost of electricity (*TCoE*). In general, the profile of '*remaining demand*' (i.e., demand after nuclear baseload) has proportionally greater and more pronounced peaks during the winter months as the contribution of conventional nuclear power increases. This causes the mix of renewables to shift towards more wind.

It can also be seen that for any one mix of wind and solar PV power, varying ***X*** (i.e. the split of energy between $H_2$ and CAES) has a strong impact on the *TCoE*. There are two main reasons. Firstly, hydrogen storage and CAES systems have markedly different costs in terms of both, storage capacity and power conversion.

Secondly, hydrogen storage has a considerably lower efficiency than CAES (45 and 70%, respectively). Therefore, storage losses increase as the value of ***X*** reduces and more energy is passed through the $H_2$ stores. Renewables produce additional energy to compensate for these losses, which increases the cost of generation. Depending on the mix of renewables, the optimum value of ***X*** is found between 0.3 and 0.5.

Fig. 5 shows the behaviour of the storage losses with respect to ***X*** (for ***N*** = 0.16 and ***R*** = 0.9). When ***X*** = 0 and all the storage capacity in the system is provided by hydrogen, renewables produce an additional ~550 TWh to compensate for the storage losses. On the other hand, when ***X*** = 1 and CAES provides all the storage capacity, the supplementary generation required to compensate for storage losses is only ~200 TWh.

Fig. 5 also shows how the amount of permissible overgeneration (and curtailment) varies with respect to ***X***. The over-generated energy improves the match between the profiles of generation of demand, which in turn helps to reduce the storage capacity required by the system.

In general, $\boldsymbol{\Omega}$ is directly proportional to ***X***. At small values of ***X***, there is a considerable amount of extra generation in the system to compensate for the increased storage losses. This leaves little room for any further over-generation. In this study, 6 discrete values of $\boldsymbol{\Omega}$ were considered: 0%, 2.5%, 5%, 7.5%, 10% and 15%. This explains the stepwise behaviour seen in the overgeneration curve. The discretization was necessary to keep the multi-variable experiment at manageable level.

Fig. 6 shows how the storage capacities of both, hydrogen and CAES vary with respect to the ratio ***X***. The storage capacity provided by CAES is directly proportional to the value of ***X***, going from 0 TWh at ***X*** = 0 to ~41 TWh when ***X*** = 1. Conversely, the storage capacity of the $H_2$ store is inversely proportional to the value of ***X***. It goes from ~105 TWh at ***X*** = 0 down to 0 TWh when ***X*** = 1.

It can be seen in Fig. 6 that the storage capacity in the form of hydrogen at values of ***X*** close to zero is much larger than the storage capacity of CAES at values of ***X*** close to one. This is owed to the much lower roundtrip efficiency of hydrogen compared to CAES. Storing electricity in the form of hydrogen has a roundtrip efficiency of ~45% [67] (~80% electrolyser and ~55% turbine [68]) whilst CAES can achieve a much higher efficiency of ~70% [24,69]. Consequently, for a given energy output, $H_2$ will need a greater energy input and larger storage capacity than CAES.

Referring to Fig. 4, for a mix of 90% wind +10% solar, the *TCoE* is minimised when ***X*** = 0.33. The total energy storage capacity required for this value of ***X*** is ~98.9 TWh. $H_2$ provides 90.7 TWh whilst CAES provides the remaining 8.2 TWh.

As mentioned in section 3, the study treats the electricity grid as a single node and determines the amount of storage capacity required to balance the system. In reality, the total storage capacity will be provided by an array of small, distributed energy stores. A reasonable assumption is that the small stores could be collocated with generation sites. However, the amount or type of storage capacity that is needed to balance the grid (which is the main concern of this paper) is not affected significantly but the location of the stores, provided these are appropriately distributed.

The rated powers of the two energy stores are another important set of system parameters. In the case of hydrogen storage, two completely different '*power conversion*' technologies are used during the charging and discharging processes. During the charging phase, electrolysers are used to convert electricity into hydrogen. During a discharging phase, hydrogen is combusted in turbines to produce electricity [70,71]. These two very different technologies have very different costs per unit power. Grid-scale CAES systems also use different power conversion equipment for charging (compressors) and discharging (expanders). However, the two sets of machinery have similar costs as the compression and expansion processes resemble each other.

Fig. 7 shows how the rated charging (Pc) and discharging (*Pd*) powers of H2 and CAES vary with respect to ***X***. The figure considers values for ***N*** and ***R*** of 0.16 and 0.9, respectively. Charging powers are shown as negative values as they are dictated by the negative part of the

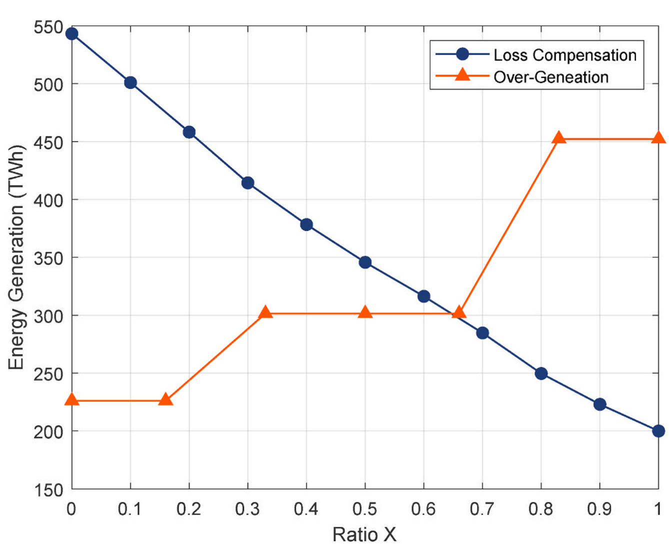


**Fig. 5.** Behaviour of additional components of renewable generation (loss compensation and over-generation) with respect to X for ***N*** = 0.16 and ***R*** = 0.9.

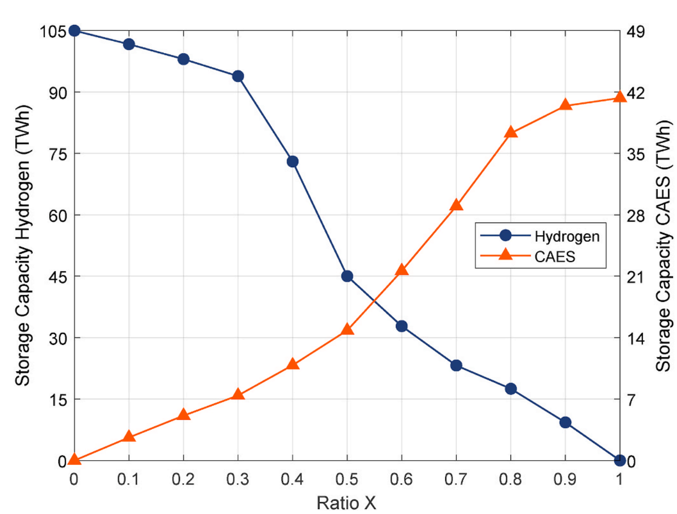


**Fig. 6.** Energy storage capacities required for different values of X (***N*** = 0.16 and ***R*** = 0.9).

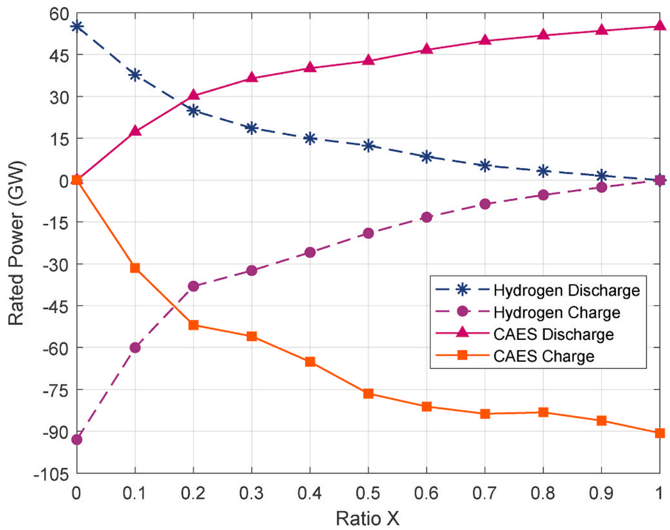


**Fig. 7.** Behaviour of the charge and discharge powers of both energy stores with respect to $\boldsymbol{X}$ ($\boldsymbol{N} = 0.16$ and $\boldsymbol{R} = 0.9$).

profile of net-demand.

The rated charge and discharge powers of CAES become greater as $\boldsymbol{X}$ increases. Inversely, the rated charge and discharge powers of the hydrogen store become greater as the value of $\boldsymbol{X}$ decreases. The maximum discharge power of either store is ~60 GW as this is limited by the profile of electricity demand (see Fig. 1).

Knowing the storage capacities, rated powers and amount of energy generated it is possible to calculate the overall system cost or '*TCoE*' for a specific scenario by means of Eq. (8). The costs shown in Fig. 4 are calculated using values provided in Table 1.

Fig. 8 provides a breakdown of the *TCoE* for a system configuration based on a $\boldsymbol{N} = 0.16$ and $\boldsymbol{R} = 0.9$. The main contributor to the overall cost is renewable generation (wind and solar combined) as it provides 84% of the total electricity demand plus an additional amount to compensate for storage losses and a further additional amount that is curtailed (between 5 and 15% of total demand). Depending on the value of $\boldsymbol{X}$, renewable generation accounts for 56–60% of the *TCoE*. The contribution of conventional nuclear power to the overall cost is constant at 14.8 £/MWh (as $\boldsymbol{N}$ is fixed here). Depending on $\boldsymbol{X}$, this represents between 18% and 20% of the *TCoE*.

The contribution of energy storage capacity to the overall system cost increases with $\boldsymbol{X}$ given that CAES has a higher cost per kWh than $H_2$. Conversely, the contribution of power conversion machinery to the total cost increases as $\boldsymbol{X}$ reduces, since $H_2$ is considerably more expensive per kW than CAES. Depending on the value of $\boldsymbol{X}$, energy storage (encompassing both storage capacity and power conversion) accounts for between 20% and 25% of the overall system cost. For a value of $\boldsymbol{X} = 0.33$, which achieves the lowest *TCoE*, renewable generation represents 58.6%, conventional nuclear power accounts for 19.9% and energy storage makes up the remaining 21.4%. Table 2 provides a summary of the technical parameters of the system configuration that achieves the lowest cost of electricity for a nuclear baseload of 16%.

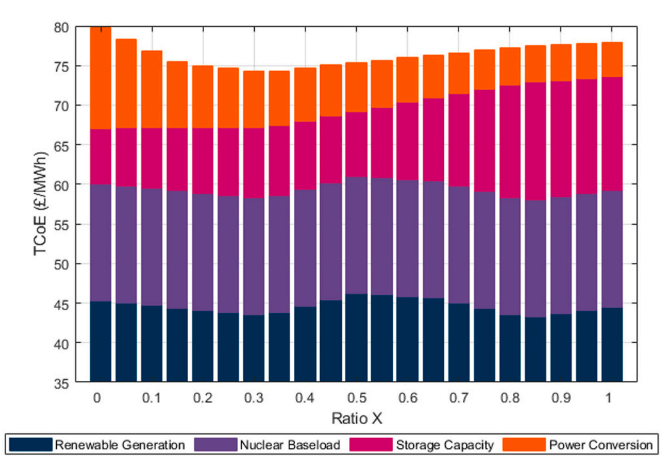


**Fig. 8.** Breakdown of the total cost of electricity for a system based on $\boldsymbol{N} = 0.16$ and $\boldsymbol{R} = 0.9$.

### 4.2. *Effect of an increasing contribution of conventional nuclear power*

Focusing on a fixed penetration of baseload nuclear power, the previous subsection discussed the effect that the three other system design variables ($\boldsymbol{R}$, $\boldsymbol{X}$ and $\boldsymbol{\Omega}$) have on some of the cost driving parameters, such as the energy storage capacity, rated charging and discharging powers of the energy stores, overall storage losses and energy over-generation. Here we will explore the effect of increasing the contribution of conventional nuclear.

Fig. 9 shows how the profile of '*remaining demand after nuclear baseload*' changes as the contribution of conventional nuclear power to the energy mix increases. The mean value of the remaining demand reduces as $\boldsymbol{N}$ increases. When $\boldsymbol{N} = 0$ the average value is 38.2 GW, while this drops to −2.4 GW for an $\boldsymbol{N} = 1$.

It can also be seen that the crest factor of the profiles increases as the nuclear baseload increases. The crest factor is the ratio of the maximum value (or amplitude) to the *rms* value of the profile and describes how extreme a waveform's peaks are. As the value of $\boldsymbol{N}$ increases, the demand peaks during wintertime become proportionally greater. In turn, this calls for an increased contribution of wind power to the energy mix and reduces the need for solar power during the summer months.

It is worth noting that at values of $\boldsymbol{N} \leq 50\%$, all the energy produced by conventional nuclear power is directly consumed. This is reflected by an entirely positive profile of '*demand after baseload*'. However, at values of $\boldsymbol{N}$ above 50%, some of the energy coming from the nuclear baseload needs to be stored. This is indicated by a profile with negative parts (see Fig. 9).

Fig. 10 shows how the profile of net-demand, which considers

**Table 2**
Technical parameters of the system configuration that achieves the lowest *TCoE* for a $\boldsymbol{N} = 0.16$

| | Parameter | Quantity |
|---|---|---|
| Demand and Generation | Total Demand over 9 years | 3015 TWh |
| | Nuclear Penetration | 0.16 |
| | Total Nuclear Baseload | 482.4 TWh |
| | Total Renewable Generation | 3115.8 TWh |
| | Base Renewable Generation | 2532.6 TWh |
| | Loss Compensation | 432.4 TWh |
| | Over-Generation ($\Omega \sim 5\%$) | 150.7 TWh |
| | Ratio *R* | 0.9 |
| | Energy from Wind | 2804.2 TWh |
| | Energy from Solar PV | 311.6 TWh |
| Energy Storage | Ratio *X* | 0.33 |
| | Total energy put into storage | 925 TWh |
| | Total output of $H_2$ | 279 TWh |
| | Total output of CAES | 213.6 TWh |
| | $H_2$ storage capacity | 90.7 TWh |
| | CAES storage capacity | 8.2 TWh |
| | $H_2$ rated charging power | −30.6 GW |
| | $H_2$ rated discharge power | 17.1 GW |
| | CAES rated charging power | −57.7 GW |
| | CAES rated discharge power | 38.0 GW |
| | $H_2$ utilisation (output/capacity) | 3.1 |
| | CAES utilisation (output/capacity) | 25.9 |
| | $H_2$ storage duration | 5313.7 Hrs |
| | CAES storage duration | 216.2 Hrs |

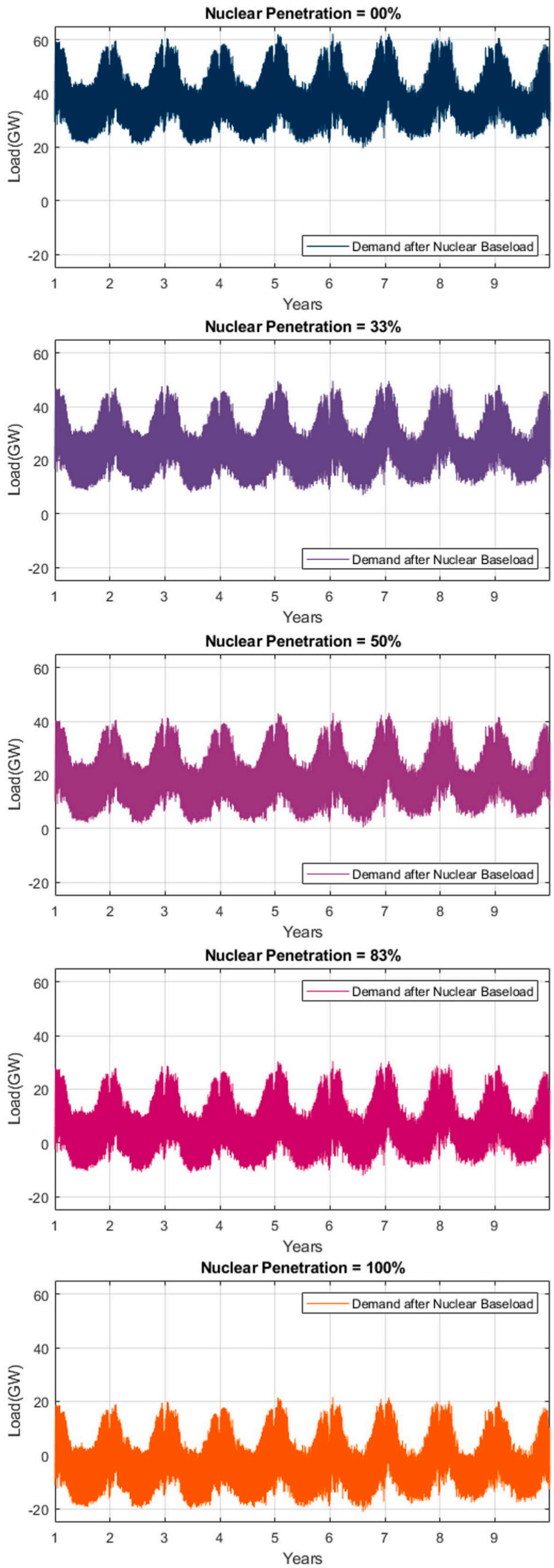


**Fig. 9.** Profile of *demand remaining after nuclear baseload* for different levels of nuclear penetration.

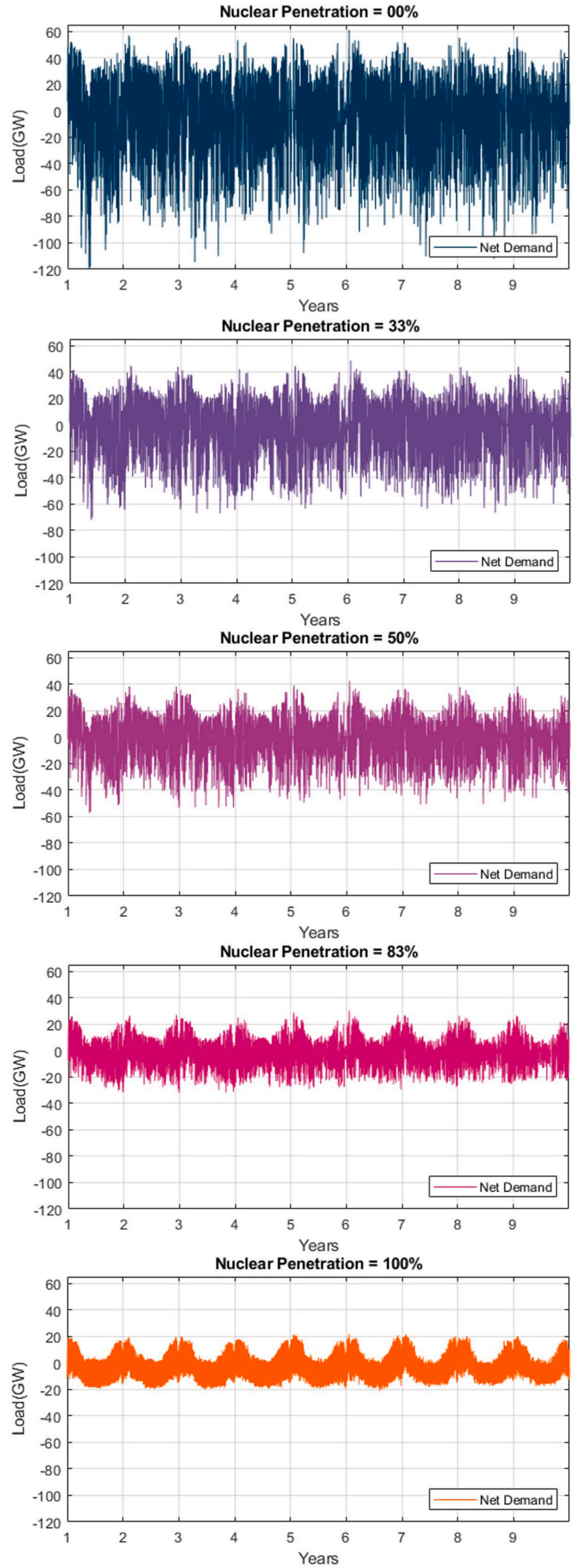


**Fig. 10.** Profile of net-demand (considering contribution of nuclear baseload and renewables) for different values of ***N***.

conventional nuclear and renewable generation, changes as conventional nuclear power contributes more to the energy mix. As $\boldsymbol{N}$ increases, renewables provide less energy. This reflects in the smaller peak-to-peak distances of the profiles of net-demand. The ratio of the minimum peak value to the profile's average value also reduces as $\boldsymbol{N}$ increases. For an $\boldsymbol{N} = 0$, this peak-to-average ratio is 24.3 while for an $\boldsymbol{N} = 1$, it is only 8.7.

Fig. 11 shows the effect that increasing the nuclear baseload has on the energy storage capacity required. Fig. 11a shows the required hydrogen storage capacity for different combinations of system parameters while Fig. 11b shows the storage capacity that will be provided by CAES. The curves shown consider the optimum values of $\boldsymbol{R}$ and $\boldsymbol{\Omega}$ for the particular value of $\boldsymbol{N}$.

Regardless of the value of $\boldsymbol{X}$ (energy split between two stores), the storage capacity required reduces as more conventional; nuclear power is introduced. For example, when $\boldsymbol{N} = 0.16$ and $\boldsymbol{X} = 0.33$, the required storage capacity in the form of hydrogen is 90.7 TWh. This reduces to 31.4 TWh when $\boldsymbol{N} = 83$. Similarly, when $\boldsymbol{N} = 0.16$ and $\boldsymbol{X} = 0.33$, CAES' storage capacity is 8.2 TWh. This reduces to 2.3 TWh when $\boldsymbol{N}$ increases to 0.83. T. Koivunen et al. [85] have also reported this behaviour. In a completely zero-carbon system, the requirement for energy storage is inversely proportional to the contribution of nuclear power. The reduction in the storage capacities of both types of stores is owed to the fact that an increase in the contribution of conventional nuclear power to the electricity mix improves the match between the profiles of demand and generation.

Fig. 12 shows how the rated charging powers of the CAES and hydrogen stores change with respect to $\boldsymbol{N}$. The curves shown consider the optimum values of $\boldsymbol{R}$ and $\boldsymbol{\Omega}$ for the particular value of $\boldsymbol{N}$. The figures show that the charging powers of both stores are inversely proportional to $\boldsymbol{N}$. As mentioned in section 3, the charging power ($P_c$) of a store is determined by the minimum value of the negative part of its work-profile.

For a value of $\boldsymbol{N} = 0.16$ and $\boldsymbol{X} = 0.33$, the hydrogen store has a power of −30.6 GW, which reduces to −11.3 GW when the penetration of conventional nuclear increases to 83%. Similarly, for a value of $\boldsymbol{N} = 16$ and $\boldsymbol{X} = 0.33$, CAES has a charging power of −57.7 GW. This reduces to −18.2 GW when $\boldsymbol{N} = 0.83$.

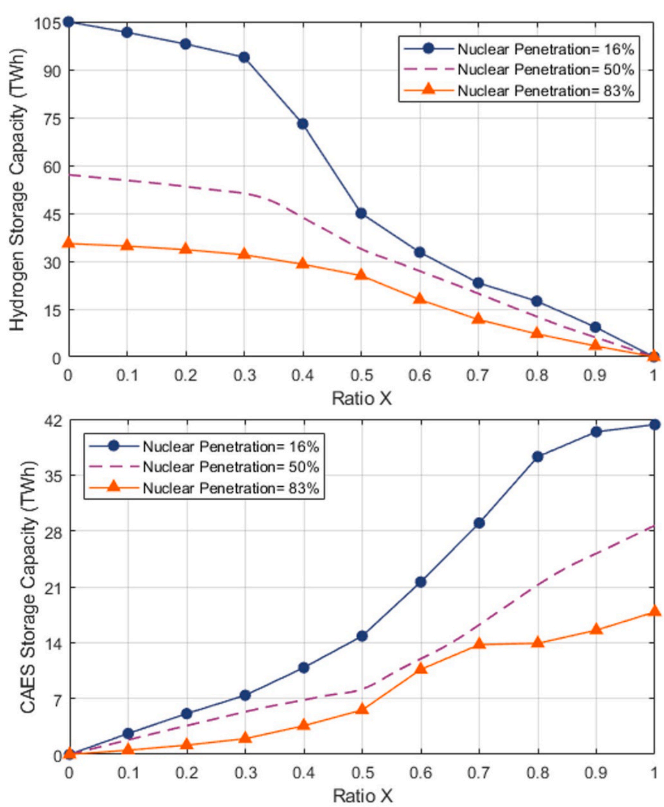


**Fig. 11.** Effect of an increasing nuclear baseload on the energy storage capacity required.

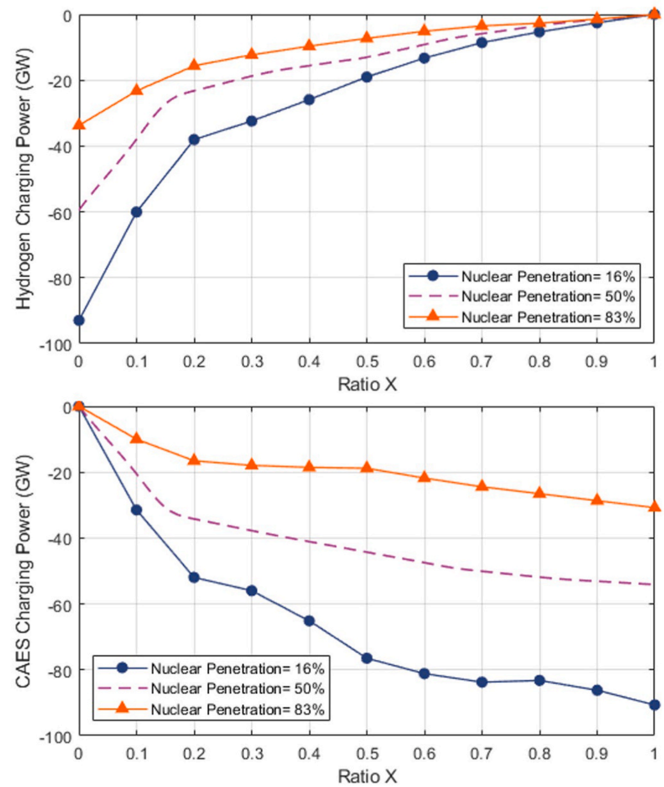


**Fig. 12.** Behaviour of the rated charging powers of the hydrogen and CAES stores with respect to $\boldsymbol{N}$.

The reason why the charging power becomes smaller as $\boldsymbol{N}$ increases is shown graphically in Fig. 10. As $\boldsymbol{N}$ increases and renewables provide less power, the profile of net-demand becomes compressed (i.e., smaller peak-to-peak value) and the minimum values found are closer to zero.

The discharging powers of the two stores are not shown in the figures; however, a similar behaviour is observed. As the contribution of conventional nuclear power increases, the discharge power of the stores reduces.

Fig. 13 shows the effect that an increasing nuclear baseload has on the overall storage losses. The curves shown consider the optimum values of $\boldsymbol{R}$ and $\boldsymbol{\Omega}$ for the particular value of $\boldsymbol{N}$. As mentioned, storage losses are inversely proportional to the value of $\boldsymbol{X}$. At smaller values of $\boldsymbol{X}$, more energy is passed through the hydrogen store, which has a lower roundtrip efficiency. Therefore, the system experiences increased losses.

Regardless of the value of $\boldsymbol{X}$, storage loses reduce for greater values of $\boldsymbol{N}$. The match between the profile of generation and demand improves as $\boldsymbol{N}$ increases. This reduces both, the amount of energy that passes through storage and the energy storage capacity that is needed. For comparison, ~931 TWh are put into storage throughout the complete 9-year period analysed when $\boldsymbol{N} = 0$, while the amount of energy that is sent into storage is ~372 TWh when $\boldsymbol{N} = 1$.

The optimum mix of storage technologies tends to move towards lower values of $\boldsymbol{X}$ (more $H_2$) as $\boldsymbol{N}$ increases, which translates into more storage losses due to a less efficient form of storage. Nevertheless, as $\boldsymbol{N}$ increases the overall losses reduce due to: *i*) the better match between the generation and demand profiles and *ii*) there is less energy that requires to be sent into storage.

Fig. 14 shows the electricity costs (*TCoE*) that can be achieved with different penetration levels of conventional nuclear power. Each one of

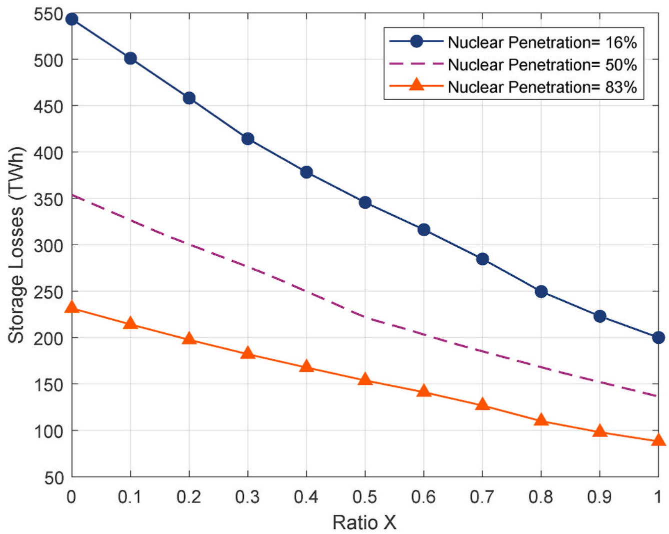


**Fig. 13.** Effect of nuclear baseload on the overall storage losses (optimum values of $\boldsymbol{R}$ and $\boldsymbol{\Omega}$ considered).

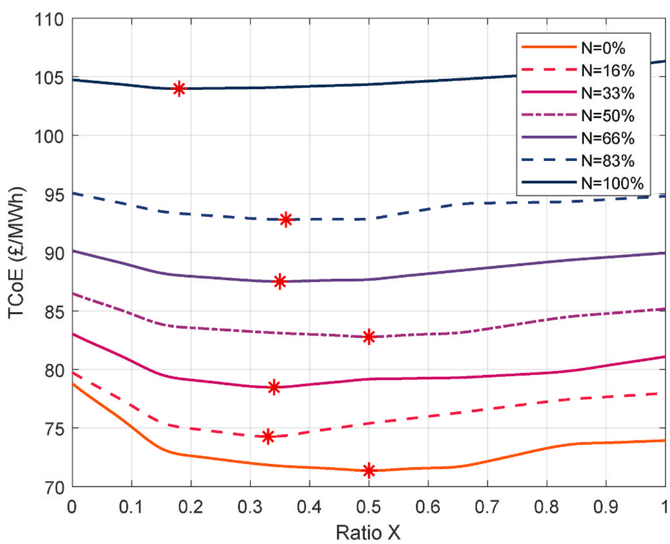


**Fig. 14.** Variation of the total cost of electricity with respect to penetration of conventional nuclear and storage mix.

the curves in the figure represents a different $\boldsymbol{N}$ value and considers the optimum values for $\boldsymbol{R}$ and $\boldsymbol{\Omega}$. In the figure, the optimum value of $\boldsymbol{X}$ for each individual level of $\boldsymbol{N}$ is indicated with an asterisk.

Fig. 14 reveals an important point. Regardless of the value of $\boldsymbol{N}$, trying to provide all the storage capacity that the system requires using a single technology (either $H_2$ or CAES) yields a higher *TCoE* than if a mix of stores were adopted.

We can see that in general, the optimum value of $\boldsymbol{X}$ moves towards more hydrogen as the contribution of conventional nuclear increases. This is linked to the fact that as $\boldsymbol{N}$ increases the overall amount of energy that needs to pass through storage reduces. Therefore, the system can afford using more of the less efficient but cheaper type of storage.

A big jump in cost is seen between $\boldsymbol{N} = 0.83$ and $\boldsymbol{N} = 1$. This is because for penetrations of conventional nuclear power below 100%, the renewables in the mix provide the additional amount of energy to compensate for storage losses. However, at $\boldsymbol{N} = 1$, this supplementary energy must come from conventional nuclear, which is ~2.3 times more expensive per MWh than wind.

Fig. 14 conveys a clear message. At a levelized cost of 92.5 £/MWh, a nuclear baseload is far too expensive for the UK electricity system. In contrast, solar PV and wind generation technology costs have reduced substantially over the last decade. Offshore wind strike prices for UK farms being built now (40 £/MWh) are substantially lower than the costs of new (conventional) nuclear generation, even before accounting for nuclear cost overruns [86], and the are expected to continue reducing.

Having a nuclear baseload will reduce the energy storage capacity that is required, as Fig. 11 shows. However, the savings in the capex of the stores are immediately overshadowed by the cost of generating electricity through conventional nuclear reactors. Therefore, as soon as a nuclear baseload is introduced to the mix the *TCoE* will increase. In a study carried out for Sweden, Kan et al. [87] concluded that the case with best economic prospects for nuclear power investment is when transmission capacity is optimal, combined with low cost for nuclear power and high cost for storage, which reinforces this paper's findings. The energy storage that a zero-carbon system requires reduces when the contribution of baseload nuclear increases. High costs of storage together with low nuclear costs would call for a greater use of nuclear power.

Fig. 15 presents in a simple way how the total cost of electricity increases with respect to $\boldsymbol{N}$. Each point in the curve considers the optimum values of $\boldsymbol{R}$, $\boldsymbol{X}$ and $\boldsymbol{\Omega}$ for a specific value of $\boldsymbol{N}$. The lowest cost of ~71.4 £/MW is achieved when there is no contribution of a nuclear baseload to the electricity mix. At $\boldsymbol{N} = 0.16$ a cost of ~74.3 £/MWh is observed, while this would increase to ~92.8 £/MWh if conventional nuclear power supplied ~83% of the total electricity demand.

The conclusion of this research aligns with other published work. Price et al. [86] examined the case for new conventional nuclear in the UK's net-zero energy system and showed that a nearly 100% variable renewable system with by long-term storage, very little fossil fuels and no new-build conventional nuclear is the most cost-effective system design. This suggests that the current UK Government policy towards nuclear is becoming increasingly difficult to justify. Price et al. also comment that: 1) new (conventional) nuclear power is not necessary to provide electricity system adequacy and security and 2) new nuclear (conventional) capacity is only cost-effective if ambitious cost and construction times are assumed, competing technologies are unavailable and interconnector expansion is not permitted.

Blakers et al. [88] carried out an hourly energy balance analysis for a 100% renewable energy Australian grid, in which wind and photovoltaics (PV) provides about 90% of the annual electricity demand and existing pumped-hydro and biomass provides the balance. The only low emission technologies considered are those that are being deployed in

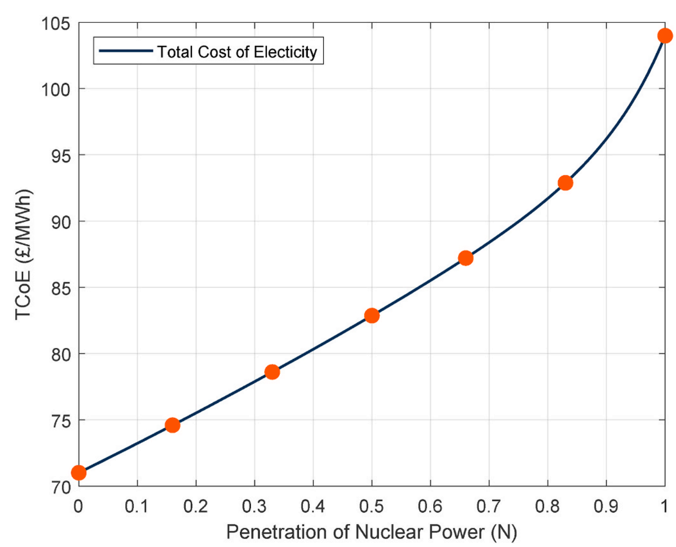


**Fig. 15.** Relationship between the total cost of electricity and the penetration of baseload nuclear power.

large quantities (>10 GW per year), namely PV and wind. On this basis, nuclear, solar thermal, geothermal and ocean energy are excluded. Nuclear energy is also excluded because of the unlikelihood of its deployment in Australia The relatively low *LCoE* (~US$70/MWh) calculated for a balanced supply of 100% renewable electricity based upon wind and PV, coupled with the large scale of these manufacturing industries, suggests that wind and PV will dominate the Australian grid in the future and it will be difficult for any other low emission technology (nuclear, solar thermal, geothermal, ocean and new biomass) to become competitive, neither on the basis of competitive supply of energy alone nor on the basis of supply of both energy and ancillary balancing services.

Child et al. [89] analysed the case of a 100% clean energy system in the Baltic region. The researchers employed an hourly resolved model that defined the roles of storage technologies (Batteries, pumped hydro, CAES, thermal storage and power-to-gas (biogas, biomethane or SNG) in a least cost system configuration. A system based 100% on renewable power represents the least cost solution and is cheaper than the current system based on nuclear power and fossil fuels. The authors report that cost savings are achieved from harnessing the flexibility of generation by various renewable energy technologies, from the interconnection of territories within the Baltic Sea region BSR and from the use of appropriate and low-cost energy storage solutions.

Child et al. [33] also carried an optimisation study for the European energy system aimed at minimising the total annualised system costs and the cost of electricity for the end user. The authors used a multi nodal model with hourly temporal resolution.

The results of the study show that a combination of flexible generation, interconnections and energy storage leads to reliable, affordable, and sustainable power, with electricity costs in the region of 60–70 €/MWh.

Flexible generation can be achieved by moderately increased levels of hydropower and capacities of dispatchable bioenergy and sustainable gas-based generation (SNG, biomethane and biogas). Interconnections between regions can reduce the need for generation and storage capacities by exploiting the natural complementarities between solar PV generation in the south, and wind generation in the northwest that result in lower variability in overall electricity generation.

Energy storage will expand significantly from current levels, with batteries primarily supplying short-term storage, and TES, A-CAES and Power-to-Gas providing seasonal balance. Nuclear reduces with time as existing plants are decommissioned between now and 2050. The authors consider that no new nuclear power plants will be installed due to high cost and sustainability reasons.

The results of the study by Child et al. [33] also show that the UK will need ~93 TWh of storage, of which more than half is provided by dispatchable gas storage. This aligns well with the findings of this paper and previous work [37], in which we report that ~50 TWh in the form of hydrogen will be needed for long duration storage. National Grid also estimates in their 'system transformation' scenario that by 2050, the electricity grid will need ~50 TWh of hydrogen storage [90].

Generally, one of the arguments in favour of introducing conventional nuclear power to the country's electricity mix is driven by the perceived reliability and energy security that having a baseload would offer as opposed to the intermittent generation from renewables. Although this argument is not wrong, energy storage technologies are already well developed and are technically capable of turning intermittent generation into dispatchable, reliable power. Moreover, this can be done at a lower price than what conventional nuclear generation currently costs. Perhaps a small nuclear baseload could provide people some peace of mind and act as a 'safety net'. However only a small contribution (<10%), can be justified in this way.

As mentioned earlier, research has been carried out to assess the feasibility of directly integrating thermal energy storage with nuclear power plants, so that their output is dispatchable rather than a baseload. This could potentially reduce the overall cost of nuclear power, enabling it to compete with variable renewables and contribute to a greater extent to the energy mix of the country.

A. Al Kindi et al. [10] carried out a techno-economic assessment of a flexible nuclear power plant in a future low carbon UK electricity system. The configuration studied is based on a 1610 MW (baseload) plant, to which 2 secondary steam Rankine cycles are added. Each of the secondary steam cycles is connected to the main nuclear power plant through a 2-tank thermal energy storage system based on phase change materials (PCM). The combined heat storage capacity of the two 2-tank thermal storage systems is 1950 $MWh_{th.}$ The upgrades offer the potential to increase the overall power output of the plant during peak load by 32% (relative to baseload nominal power), going from 1610 MW to 2130 MW.

The whole-system economic benefit of flexible nuclear plants comes from a reduction in the total system electrical infrastructure cost resulting from replacing conventional with flexible nuclear plant. Enhancing the flexibility of nuclear plants increases the capability of the system to cost-effectively integrate variable renewables, and on the other hand reduces the requirements for others means of flexibility such as batteries and hydrogen production and storage.

Al Kindi et al. [10]reported that net whole-system benefits of up to £42.7 m/year could be observed by upgrading a single plant. It is also pointed out that the value of this technology (flexible nuclear) is system dependent and varies considerably with system characteristics such as the generation mix, level of flexibility, etc.

Flexile nuclear plants could have multiple uses outside the electricity section, such as using the stored heat to match heating demand and to operate thermally driven processes like production of hydrogen or synthetic fuels. Research effort should be dedicated to exploring this in more detail.

P. Romanos et al. [11] carried out a similar analysis where they studied the integration of a 670 MW baseload nuclear plant (not intended for flexible operation) with thermal energy storage (TES) and two secondary power plants based on Organic Rankine Cycles (ORC). During off-peak demand, steam can be extracted from the main nuclear power plant to charge an array of PCM based thermal storage tanks. Subsequently, these tanks can discharge heat to a secondary ORC power plant to generate power in addition to that of the base nuclear plant.

This solution allows over-generation during peak demand, whereby the total power output is higher than the base plant's rated capacity thanks to the additional power delivered by the secondary ORC power plants. The authors found that the plant studied could deliver a maximum power of 822 $MW_{el}$ during peak times, which is 23% more than the base plant's nominal power. The integration with heat storage also allows for a 40% duration (i.e power output down to 406 MW).

Romanos et al. [11] highlighted that challenges relating to the development and integration of TES systems into nuclear power plants can be strongly facilitated by harnessing experience from existing '*Concentrated Solar Power*' plants. The authors also mentioned that the secondary ORCs used can have hot starts times of less than 10 min (and service. 10 s when already at temperature), which can significantly expand a nuclear power plant's capability to offer primary and secondary frequency responses and consequently higher profitability in ancillary markets.

Similar studies focused on integrating different types of thermal energy storage and secondary power cycles into existing nuclear power plants have been carried out by F. Carlson et al. [12–14], K. Amuda [15], A. Kluba [16] and C. Forsberg et al. [17]. Most of these studies conclude that higher outputs than the design point of the base nuclear plant can be achieved through the integration of TES and secondary power cycles. J. D. Jenkins et al. [91] and P. Denholm et al. [92] have investigated the benefits of nuclear flexibility in power systems with high penetration of wind and solar.

### 4.3. What if the cost of nuclear power reduces?

With an installed capacity of ~8 GW, conventional nuclear power currently supplies approximately 16% of the UK's electricity demand. However, almost half of the country's nuclear capacity will be retired by 2025 and much of the remainder shortly after that [93]. The possibility of refurbishing existing plants and integrate them with heat storage to extend their service life exists and should be explored, as the marginal costs of such existing assets is in the order of ~25 £/MWh [43].

In recent years the reputation of nuclear generation in the UK has suffered due to the controversy surrounding EDF's conventional nuclear plant currently under development in the south of England. Hinkley Point C has a 35-year government deal to deliver baseload power at 92.5 £/MWh [94], which is considerable higher than the current cost of wind and solar power in the country. Furthermore, the project has experienced numerous delays, and the overall cost is now estimated at ~£5 bn. Over the original budget [95]. Notwithstanding, the UK government emphasised in its recently published *Energy Security Strategy*, the need for expanding the country's nuclear generation capacity to deliver a clean electricity system by 2025. The document outlines for the construction of an additional 16 GW of capacity [8,96].

As demonstrated in subsection 4.2, new conventional nuclear generation cannot be economically justified at a cost of 92.5 £/MWh. However, if this figure reduces below a certain threshold, conventional nuclear power could very possibly have a role to play in a future UK net-zero electricity system. Fig. 16 shows the effect that a reduction in the cost per MWh of conventional nuclear generation with respect to the levelized cost of wind (40 £/MWh) has on the total cost of electricity (*TCoE*).

The curve at the top of the figure is the same curve presented previously in Fig. 15 and considers a cost of 92.5 £/MWh for nuclear power, equivalent to ~2.3 times the cost of wind. Each one of following curves considers the same system parameters and economic figures given in Table 1, but a lower cost per MWh for the contribution of nuclear power (with respect to the cost of wind).

It can be seen that at costs of 1.9× the cost of wind (~75 £/MWh) and above, the lowest *TCoE* of 71.35 £/MWh is achieved when conventional nuclear power does not contribute to the energy mix (i.e. $\boldsymbol{N} = 0$). However, at costs below 1.9× wind, having a small nuclear baseload in the mix starts to make economic sense. At 1.8× the cost of wind (72 £/MWh), the lowest *TCoE* of 71 £/MWh is achieved with a penetration of conventional nuclear power of 15%. At 1.6× the cost of wind (64 £/MWh), having a nuclear baseload slightly over 50% leads to the lowest *TCoE* of 68.5 £/MWh. Finally, at a cost of 1.5× wind (60 £/MWh), the lowest cost of electricity of 65.8 £/MWh is achieved through a penetration of conventional nuclear of 80%. At this point, nuclear power is still significantly more expensive than wind but the savings in energy storage capacity required offset the higher cost of generation. From an economic standpoint, it is sensible to supply most of the country's electricity demand through conventional nuclear power.

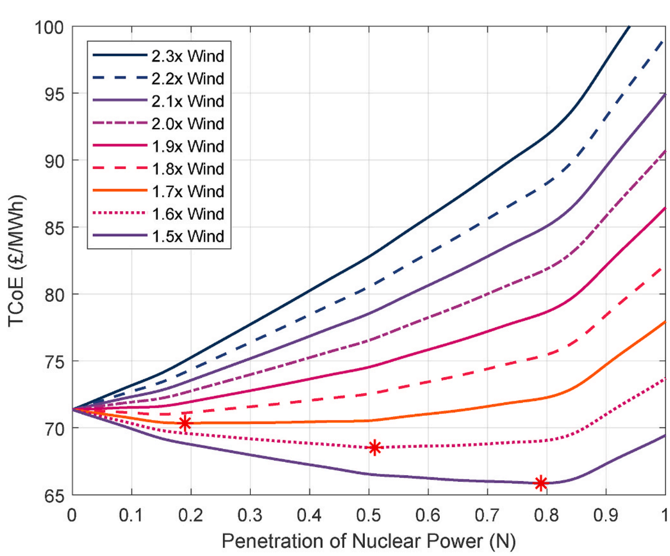


**Fig. 16.** Effect of a reduction in the cost of nuclear power on the total cost of electricity.

Rolls-Royce is developing a concept for factory-built nuclear power plants based on small modular reactors (SMR), which are similar to those used to propel nuclear submarines. The design philosophy behind these SMR power stations has a strong focus on modularisation and on maximising the manufacturing and assembly activities that are carried out inside a factory rather than on-site. This not only removes some of the cost and risk of complex construction programmes [97] but also allows SMRs to be built quicker than traditional reactors, shipped by container from the factory and installed relatively quickly on any proposed site [98].

Rolls-Royce's SMR nuclear stations will have a capacity of 470 MW, which is equivalent to ~155 onshore wind turbines or enough to power ~1.3 million homes. The modular plants will have an estimated service life of 60 years and are expected to occupy a 10-acre site, which is approximately 1/10 of the size of a conventional nuclear plant [97].

An additional feature of Rolls-Royce's modular nuclear stations is that one SMR could produce ~170 tonnes of $H_2$ or ~280 tonnes of a net-zero synthetic fuel per day, helping to decarbonise other sectors beyond the electricity grid [99].

The estimate cost of an SMR based nuclear station is ~£2.2 bn., although Rolls-Royce expects it could reduce to about £1.8 bn. This translates into levelized cost lower than 60 £/MWh (or 1.5× the current cost of offshore wind), which could make SMR technology very competitive against renewables. Advances in manufacturing and economies of scale could drive the cost down further [94,100]. Regulatory approval from the British government for the modular reactors Rolls-Royce is expected by 2024 with the first stations to start providing power to the national electricity grid by 2029 [101].

If the proposed SMR technology does achieve the expected costs of <60 £/MWh, nuclear power may have (as Fig. 16 shows) an important role in a future zero-carbon energy sector in the UK.

## 5. Concluding remarks

The reputation of nuclear power in the UK has suffered due to numerous problems surrounding the construction of Hinkley Point C, in addition to the agreed deal for it to deliver baseload electricity at 92.5 £/MWh over 35 years, which is 2.3× more expensive than what wind power currently offers.

Notwithstanding, the UK government has emphasised the need for expanding the country's nuclear capacity. One of the arguments is the reliability and energy security that a baseload offers as opposed to the intermittent generation from renewables.

However, energy storage technologies are already capable of turning intermittent generation into dispatchable, reliable power and this can be done at a lower price than what conventional nuclear costs. Wind and solar PV power in the UK have achieved costs that are ~56% and ~35% lower than the cost of conventional (baseload) nuclear and they are expected to continue reducing.

This paper has demonstrated that considering the current costs of conventional nuclear, renewables and energy storage technologies, the cheapest way to achieve a zero-carbon electricity system in the UK is through a combination of '*renewables* + *storage*' without having a nuclear baseload in the system.

Introducing a nuclear baseload will indeed reduce the energy storage capacity that is required in a zero-carbon system compared to a system based 100% on renewables. A nuclear baseload will also reduce the required rated powers of the energy stores. However, the savings in the capital cost of the energy storage infrastructure are overshadowed by the cost of generating electricity through nuclear reactors. Introducing a nuclear baseload to the energy mix will increase the total cost of electricity (*TCoE*).

This paper has also shown that the crest factor (a measure of how extreme a waveform's peaks are) of the profile of '*demand after nuclear baseload*' increases as more conventional nuclear power is incorporated into the system. As the penetration of conventional nuclear increases, the wintertime demand peaks become proportionally greater, which calls for an increased contribution of wind power and reduces the need for solar power during summertime.

When renewables provide 100% of the country's electricity demand, a *TCoE* of ~71.4 £/MWh can be expected. With a penetration of conventional nuclear of 16%, the cost of electricity increases to 74.3£/MWh whilst with a nuclear baseload of 83%, the TCoE will increase up to 92.8 £/MWh.

At a levelized cost of 92.5 £/MWh, conventional nuclear power is too expensive for a UK zero carbon system. A small nuclear baseload (<10%) could be justified for the purpose of providing a sense of 'security of supply'; however, this will entail an increased cost of electricity.

If the cost of nuclear power reduced below a certain threshold, it could have a role to play in a future UK net-zero electricity system. At a cost of ~1.8× the cost of wind, a small penetration of conventional nuclear makes economic sense. At this cost, a TCoE of ~71£/MWh can be achieved with a nuclear baseload of 15%, which is slightly cheaper than what is attainable through a system 100% based on renewables (71.4 £/MWh).

At a cost of 1.5× the cost of wind (60 £/MWh), a nuclear baseload of 80% achieves a TCoE of 65.8 £/MWh. At this point, nuclear power is still significantly more expensive than wind but the savings in the energy storage capacity required offset the higher cost of generation.

Rolls-Royce is developing small modular reactors (SMR) with a capacity of 470 MW. It is estimated that the cost of these nuclear stations could be in the region of ~£1.8 bn. This translates into a levelized cost lower than 60 £/MWh (or 1.5× the current cost of offshore wind), which would make SMR technology competitive against renewables.

If the SMR technology achieves the expected costs of <60 £/MWh and the costs of renewables do not reduce considerably during the following years, nuclear power could have an important role in a zero-carbon electricity system. With a cost of 60 £/MWh, nuclear power could potentially provide a baseload of up to 80% of the UK's electricity demand.

There is ongoing research on integrating conventional nuclear power plants with thermal storage. Coupling plants directly with storage (before electricity is produced) transforms them from baseload generators to 'load following plants. This is a promising avenue that should be further explored as it has the potential of increasing the cost-effectiveness of nuclear plants by: *i*) enabling them to have a dispatchable output and *ii*) offering the possibility of delivering process heat and integrating to wider energy systems. Existing conventional nuclear plants could also be retrofitted with thermal storage as part of refurbishment plans to increase their service life. Storing nuclear energy as heat before transforming it into electricity will also increase the overall efficiency of the system as the number of transformations is reduced. If 'nuclear + direct heat storage' achieves costs comparable to what 'renewables + storage' currently offer, it can have a considerable role to play in a future UK zero-carbon electricity system.

## Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

## Acknowledgements

The authors would like to thank the United Kingdom's Engineering and Physical Sciences Research Council (EPSRC) for supporting this work through the following research grants: 'Generation Integrated Energy Storage – A Paradigm Shift' (EP/P023320/1) and 'Sustainable, Affordable and Viable Compressed Air Energy Storage' (EP/W027569/1). The authors would also like to express their gratitude to the reviewers who contributed to improving the quality of this paper.

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