Resource Adequacy in the 2030s

Modelling Approach

March 2025

Security of Supply

NESO
National Energy System Operator

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Introduction

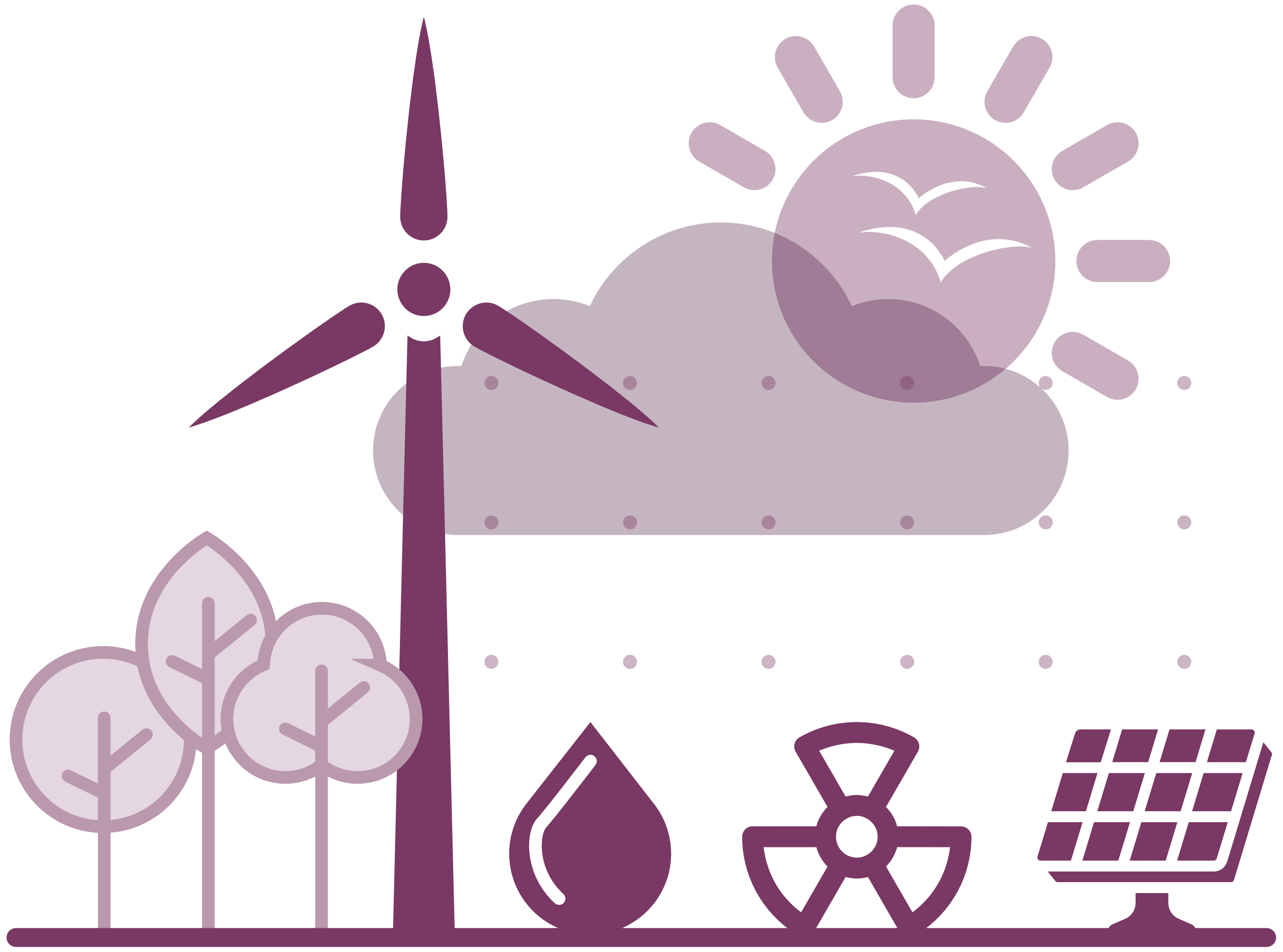
It is essential that we continue to deliver reliable electricity supplies to consumers as Great Britain's energy systems are decarbonised. This is particularly significant for the 2030s, as more renewables, new technologies and flexible resources are expected to be deployed on the power system.

NESO plays a key role through our primary duties, taking a proactive approach to identify potential risks and working with stakeholders to mitigate them ahead of time. This includes our ongoing work across multiple areas, such as resource adequacy, which ensures security of supply, and operability, which provides confidence that we can continue to operate a safe and secure system.

We intend to publish our next study assessing resource adequacy in the 2030s in spring/early summer 2025. This will build on our previous study with AFRY and reflect recent developments in the energy sector, particularly efforts to accelerate decarbonisation through the government's Clean Power 2030 Action Plan, which was informed by NESO's advice.

In this spotlight report, we explain how we intend to carry out our resource adequacy modelling. It is aimed at a technical audience with a greater interest in modelling approaches. We are publishing this now to help stakeholders better understand our modelling ahead of our upcoming resource adequacy assessment.

While our current resource adequacy work focuses on the electricity system, it is increasingly important to consider how the whole energy system provides reliable supplies. In autumn 2025, we will publish our first *Gas Supply Security Assessment*, a new responsibility assessing the availability, deliverability and reliability of gas. In the longer term, we may extend this work to hydrogen and integrate different energy vectors into a coherent energy security study.



How Resource Adequacy Fits into NESO's Wider Role

The National Energy System Operator

The UK's 2023 Energy Act set the legislative framework for an independent system planner and operator to be set up to help accelerate Great Britain's energy transition, leading to the establishment of the National Energy System Operator (NESO).

Primary duties

NESO will promote the following three objectives:

Security of Supply

Ensuring security of supply for current and future customers of electricity and gases.

Resource adequacy identifies risks to security of supply and how they can be mitigated.

Net Zero

Enabling the government to deliver on its legally binding emissions targets.

Resource adequacy identifies the clean technologies needed to ensure reliable electricity supplies.

Efficiency and Economy

Promoting efficient, coordinated and economical systems for electricity and gas.

Resource adequacy identifies the resources needed well in advance to enable efficient investment decisions.

Secondary duties

NESO will also have regard to:

Facilitating Competition
Creating and maintaining competitive energy markets and networks.

Consumer Impacts
Understanding what changes mean for consumers.

Whole System Impacts
Understanding linkages across systems.

Facilitating Innovation
Creating an environment that enables others to help solve energy challenges.

Engaging with Stakeholders

We continue to invite feedback and welcome engagement with stakeholders. We are happy to clarify any aspects of our modelling approach that may be unclear, either through direct communication or via appendices to the main report. In our evolving role as NESO, we also welcome thoughts on the future extension of this work to include the whole energy system.

Our contact email address is: Box.NetZeroAdequacy@nationalenergyso.com.

Table 1: Timeline of the ESO and NESO activities on resource adequacy in the 2030s.

Date	Activity
Dec 2022	First study, *Resource Adequacy in the 2030s*, published with AFRY
Mar 2023	Stakeholder engagement including round-table debates and bilateral discussions
Jul 2023	Published an update, *Planning for Further Studies*, reflecting themes from stakeholder engagement and outlining our intentions for the next study, a series of spotlights and establishing an expert advisory group
May 2024	*Spotlight: Exploring approaches and metrics to assess resource adequacy in a full decarbonised power system*
Jul 2024	*Demand-Side Response Spotlight Study* exploring the role of demand-side response (DSR) in resource adequacy
Nov 2024	NESO *Clean Power 2030* report published
Mar 2025	Spotlight setting out the modelling approach for our next study
Spring/Summer 2025	Next resource adequacy study, focusing on electricity security of supply in the 2030s

Overview

What is a resource adequacy assessment?

A resource adequacy assessment aims to understand the risk of an electricity system being unable to fully meet customer demand.

The future is uncertain, and it is difficult to predict supply and demand patterns with absolute certainty. It is important to reflect this uncertainty in our resource adequacy modelling. We achieve this by using scenarios and sensitivities. These do not cover every possible outcome but are designed to cover a wide range of potential risks that could impact security of supply. Many of these cases are framed as 'what if' scenarios to explore different risk factors.

It is important to run a large number of simulations for each case to reflect the variability in key factors like plant availability and weather. Plant availability is inherently random, as it is impossible to predict exactly when a plant will experience an outage. By running multiple simulations with different outage patterns, we can model this variability. Similarly, we assess weather variability by using different historical weather years. Our model currently uses 34 years of historical weather data from 1984 to 2018.

A resource adequacy assessment must quantify potential risks to security of supply using appropriate metrics. In Great Britain, the Reliability Standard is based on Loss of Load Expectation (LOLE), which represents the expected number of hours per year when demand exceeds supply, and Expected Energy Unserved (EEU), which measures the expected volume of supply shortfalls in megawatt-hours (MWh) per year. In May 2024, we published a spotlight on resource adequacy metrics, highlighting the importance of assessing shortfall risks separately for different years of historical weather patterns. Statistical evaluations of shortfall volumes, frequencies, depths and durations – for each historical weather year – will form a key part of our resource adequacy assessment.

1. Appropriate set of supply and demand scenarios that consider the range of future uncertainty.

2. Large number of simulations that reflect the variability in key factors such as plant availability and weather.

3. Determination of meaningful metrics to quantify the potential risks.

The need for a resource adequacy model

NESO uses a pan-European economic dispatch model of the power system, PLEXOS, which enables us to simulate the electricity market in Great Britain and Europe for every hour of the year through cost optimisation. This highly complex model includes thousands of individual power plants across Great Britain and Europe.

However, for resource adequacy assessments, detailed dispatch data is less important. Instead, the focus is on identifying periods of higher shortfall risk and understanding how different scenarios, stress tests and weather conditions affect this risk. This creates a modelling trade-off: we can either use a detailed dispatch model or simplify the model to reduce runtime and explore more scenarios, stress tests and weather conditions.

We have developed a simplified hourly dispatch model within PLEXOS for our 2030s resource adequacy studies. This enables us to assess security of supply across a broader range of scenarios and conditions. By using a sequential hourly model of dispatch – rather than a simpler capacity assessment – we can capture the intertemporal behaviour of energy storage and weather patterns, and we can assess metrics related to the nature of lost load events.

Key trade-offs and simplifications:

- **Economics:** Our resource adequacy model is not intended for full economic assessment. Market prices and profits cannot be derived from this approach.
- **Dispatch:** Detailed dispatch information is not provided, as the model uses a broad merit-order approach, grouping technologies with similar characteristics.
- **Interconnection:** The availability of supplies from Europe may sometimes be limited. We factor this into our model using the method detailed on page 22.
- **Network constraints:** Our resource adequacy model does not currently consider network constraints in Great Britain, but they may be included in the future. Since the network is most likely to be constrained during periods of high renewable generation, we generally do not expect transmission constraints to be a significant factor during supply shortfalls. However, these constraints could affect storage levels.

A broad modelling approach

Our hourly resource adequacy dispatch model is designed specifically for resource adequacy assessments.

Its primary output, for a given set of inputs, is the timing and volume of unserved energy. By running the model across a large number of different plant outage patterns, we can use these time series to assess security of supply risks. This can be done individually for each year of historical weather data (allowing us to draw conclusions about the impact of different weather types), or by averaging results across all weather data. The latter is used for calculating LOLE and EEU.

The dispatch model minimises expected operating and fuel costs in Great Britain over the course of a year, while ensuring a given security of supply level. A high cost is associated with any unserved energy. The model uses a broad merit-order approach, grouping technologies with similar characteristics. To avoid overly optimistic outcomes, only a limited amount of foresight is allowed at each step of the optimisation process. This is particularly important for long-duration storage (including hydrogen), which might otherwise allocate energy resources unrealistically perfectly throughout the year.

Since unserved energy events are more likely to occur in winter, for each future year of interest, we run simulations from 1 April of that year to 31 March of the following year. This approach means we model each winter in full within a single simulation, allowing us to observe whether energy stores are sufficiently replenished during spring and summer in preparation for winter.

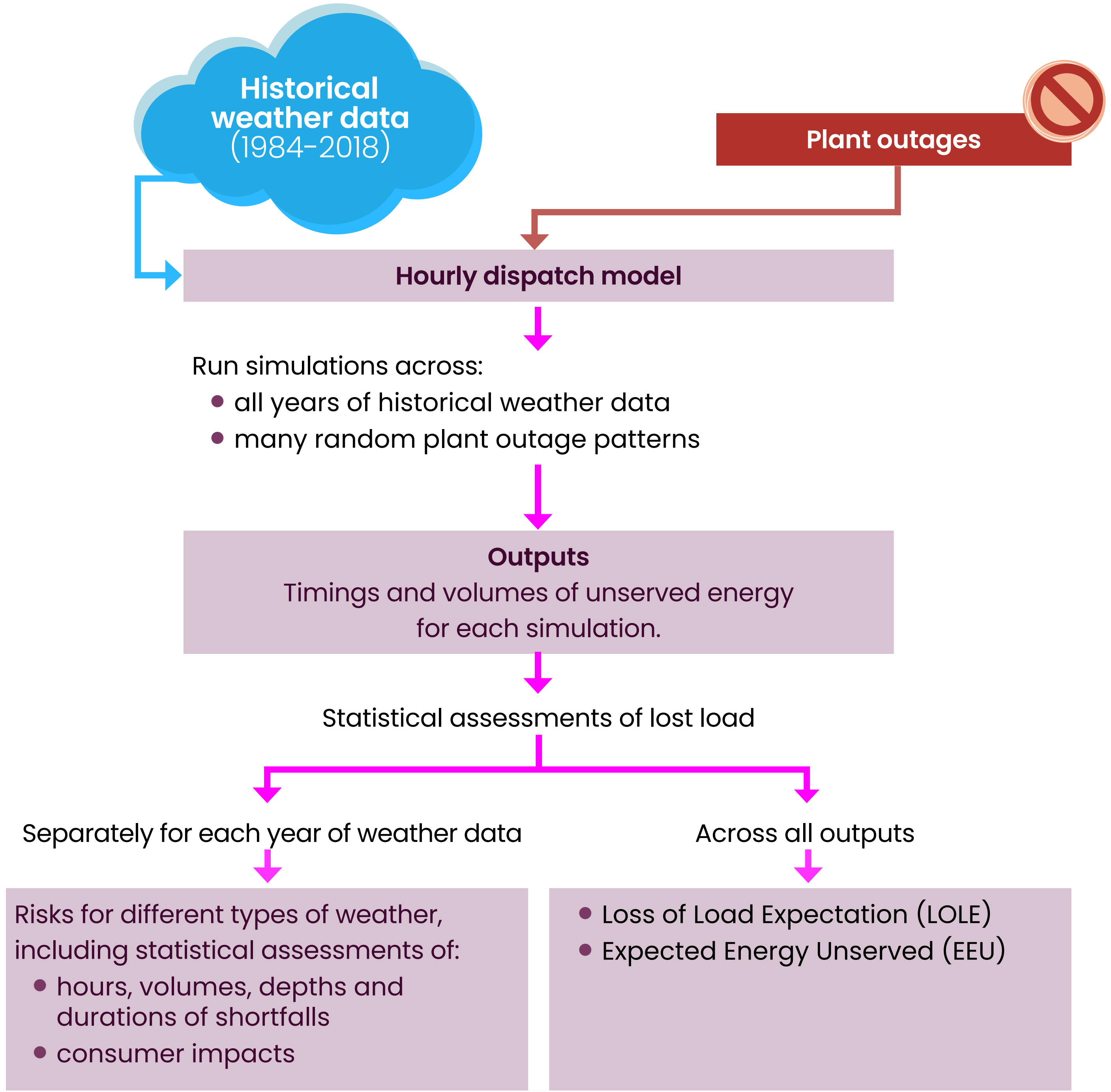


Figure 1: The broad modelling approach used to assess resource adequacy. We follow this approach for each scenario or sensitivity that we model.

Model Inputs

Model components

The main components of the resource adequacy model are shown in Figure 2 and described in more detail later. While we have specified different forms of generation and energy storage, this is not an exhaustive list – new technologies can be added as required.

Reserve margin: A reserve margin must be maintained at all times to ensure safe operation of the electricity system. In our model, this is assumed to be provided by gas, thermal, waste or biomass plants; however, in reality it could be provided by other sources as well. The reserve margin level will be set in line with NESO's latest assumptions.

Intended LOLE level: This input specifies a LOLE target for the model. In our modelling, we assume the intended LOLE level is well within the Reliability Standard of three hours per year, aligning with current reliability levels.

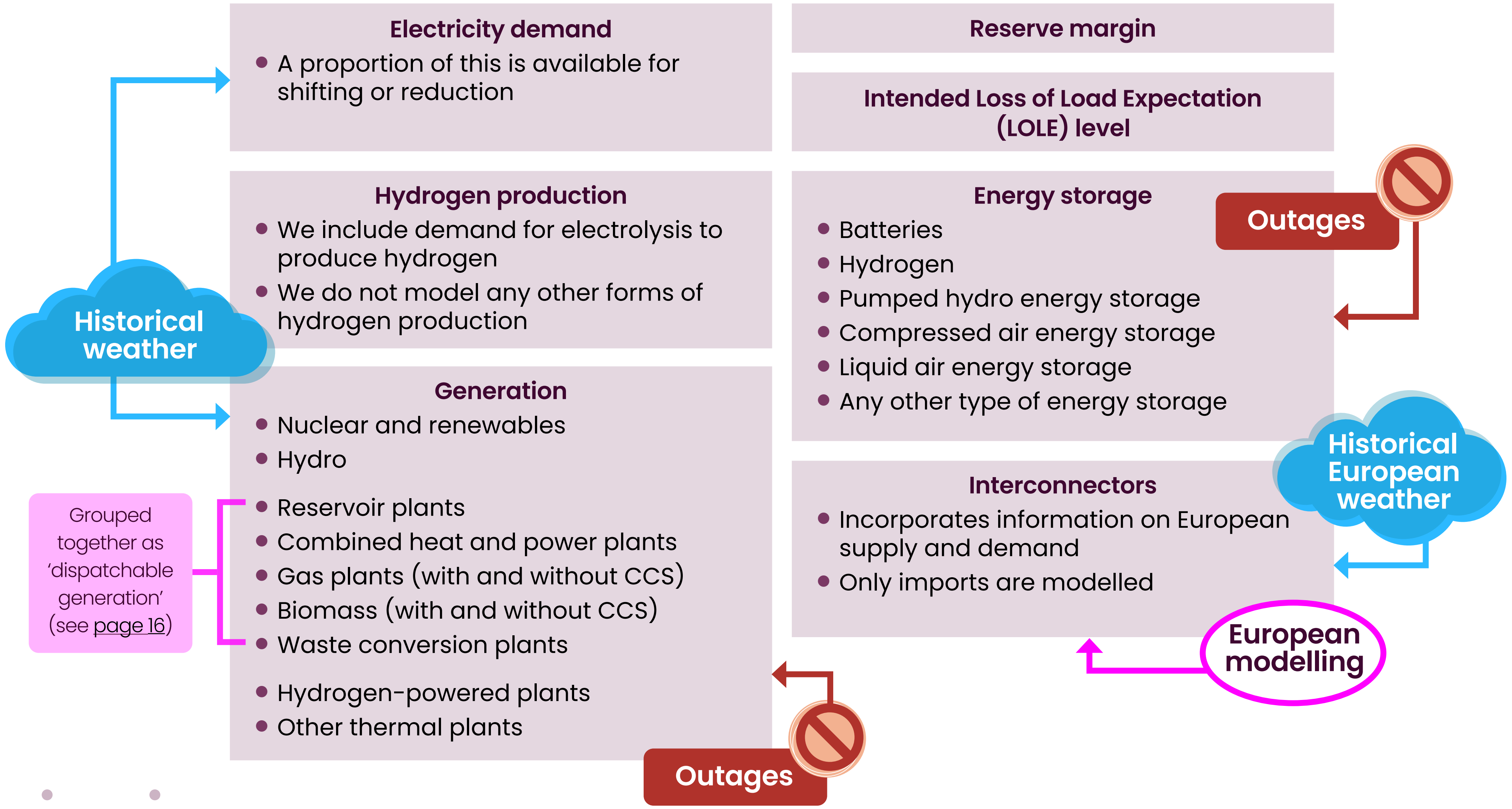


Figure 2: An overview of the key components included in the resource adequacy model.

Demand

Electricity demand
(excluding hydrogen production demand)

We use an hourly time-series of power demand that varies for each year of historical weather studied (1984–2018). For example, heating demand is higher during colder winters. For our next study, assumptions will align with the CP30 report for 2030 and the FES 2024 Holistic Transition pathway beyond that. Annual and peak demands will broadly match these pathways for a typical year of historical weather.

Some customer demand is considered flexible, meaning consumers will reduce or shift their demand in response to market signals. This behaviour can help balance supply and demand. These markets are described in more detail on page 14.

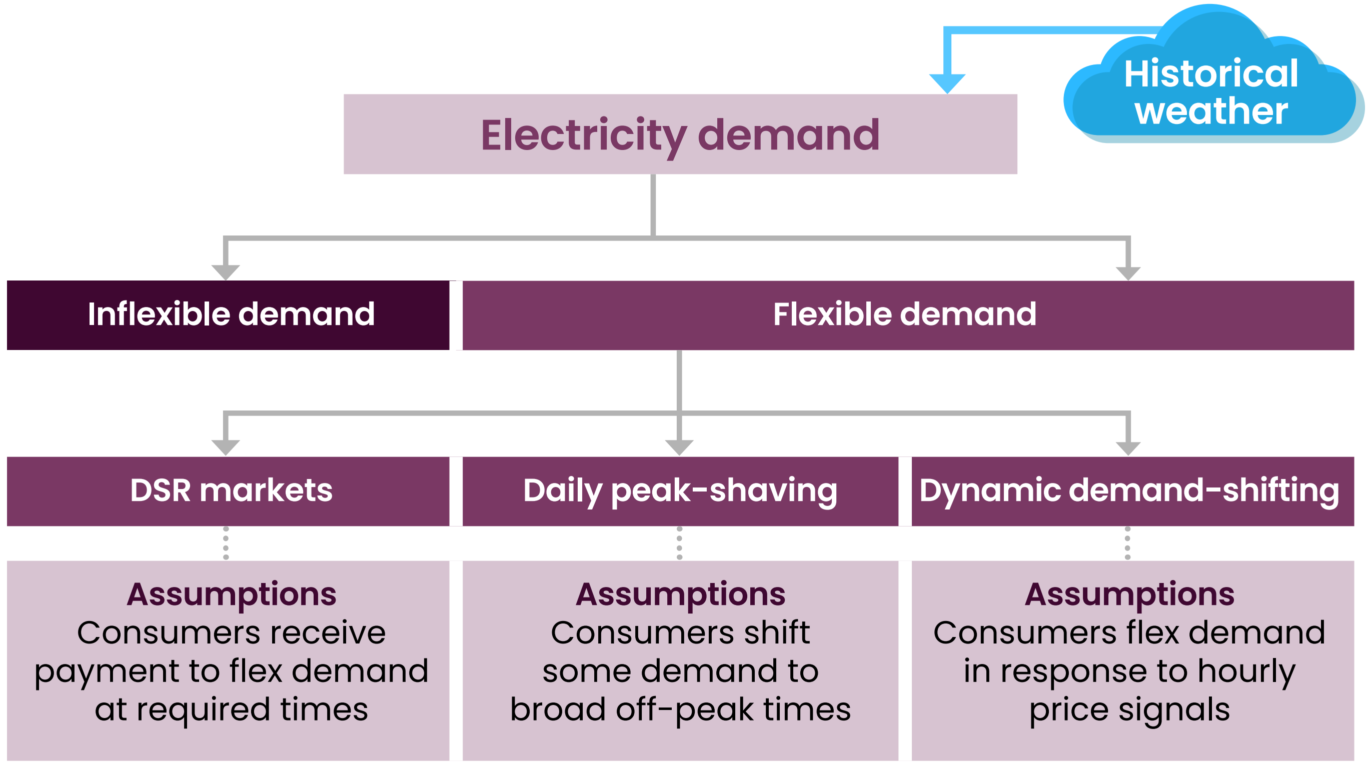


Figure 3: Illustrates the breakdown of electricity customer demand and the demand-side flexibility mechanisms incorporated in the model.

Hydrogen demand

Hydrogen could play a growing role in industry, transport and heating in the 2030s. Some of this hydrogen demand is likely to be met through steam-methane reformation (SMR) and imports, which do not affect the electricity system and are therefore excluded from our model.

Other hydrogen demand from these sectors may need to be met through electrolysis, which would increase electricity demand. In our model, this is represented as a constant addition to power demand across all times. While in reality, this demand would vary and might even provide a demand-side response service, fully capturing this requires a deeper understanding of future hydrogen industry behaviour. We plan to incorporate this into future studies as more information becomes available.

Electrolysis can also be used to fill hydrogen stores, which then convert the hydrogen back to electricity during more expensive periods. Overall electrolysis load, therefore, will be variable across the year. This is covered on page 20.

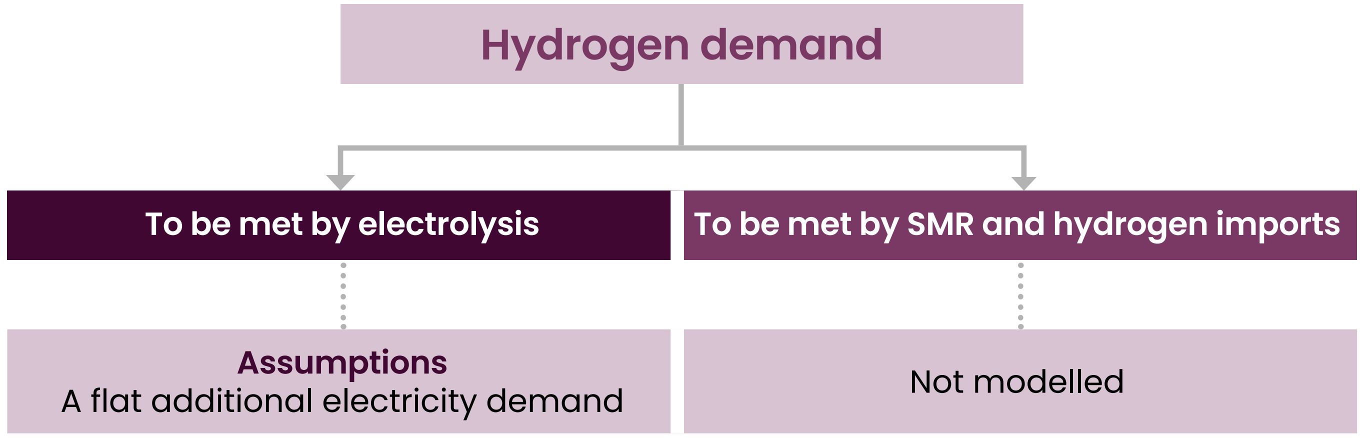


Figure 4: Outlines the two potential sources for meeting hydrogen demand and the assumptions used in the model.

Flexible demand

Some consumers may reduce or shift their demand in response to market signals. This has been demonstrated in recent trials of the Demand Flexibility Service (DFS) and through the uptake of time-of-use tariffs.

We model the following types of consumer participation:

- **Demand-side response (DSR) markets**, where consumers might adjust their demand on request in markets such as the DFS and the Capacity Market.

  How we do this: In our model, we assume that half of participating consumers will reduce demand, while others will shift their power usage by up to four hours. This assumption aligns with our *DSR Spotlight*.

  Since consumer participation is uncertain, we assume these services are only used during the most expensive periods. This means they are prioritised for preventing unserved energy or avoiding the use of stored energy reserves, rather than being treated as an everyday service.

- **Daily peak-shaving**, where behavioural changes may lead consumers to shift some of their demand to off-peak times. Time-of-use tariffs currently incentivise this behaviour, offering lower electricity prices at night compared to peak times.

  How we do this: Our model represents this type of participation as a set hourly profile. It does not dynamically respond to real-time costs but instead replicates consumer behaviour by shifting demand to broad off-peak times.

- **Dynamic demand-shifting**, where consumers might shift their demand based on real-time prices, which could be facilitated by smart metering and dynamic pricing.

  How we do this: In line with our *DSR Spotlight*, we assume that consumers will shift their demand by no more than four hours. This serves as a useful stress test for resource adequacy assessments, though further research is needed to refine our understanding of likely consumer behaviour.

Summary of flexible demand

Table 2: Summary of flexible demand.

Category	DSR Markets	Daily Peak-Shaving	Dynamic Demand-Shifting
Behaviour	Used only during the most expensive periods	Some demand is shifted to off-peak times	Dynamic hourly arbitrage based on hourly costs, to minimise daily demand costs.
Shifting or reduction?	**Both** Some customer demand is available for reduction, while some can only be shifted	Shifting only	Shifting only
Hourly limit of demand reduction (MW)	**Yes**	N/A	**Yes** Variable across the day based on assumed consumer behaviours
Daily limit of demand reduction (MWh)	**Yes**	N/A	**Yes** Weather-dependent for heating demand

Generation in Great Britain

Our model includes all forms of generating plants in Great Britain. To improve the efficiency of simulations, we have grouped these into categories based on similar operating characteristics, which are aggregated across each group (see Table 3 on the next page). In creating these categories, some technical properties, such as ramp rates and minimum up/down times, have been omitted. These properties should not significantly affect resource adequacy, and we believe the benefits of more efficient simulations outweigh these trade-offs.

Renewables (wind, solar and tidal)

These plants have very low running costs and will operate whenever possible. They are characterised by an aggregated power capacity, which is weather-dependent and varies hourly.

Hydro

These plants are low-cost to operate but are constrained by daily generation limits.

Reservoir

Reservoir-based generators have the same characteristics as hydro plants but also have a physical limit on stored water (or energy).

Hydrogen-to-power plants

These are assumed to be powered by hydrogen produced through electrolysis. Further details are provided in later sections.

Combined heat and power (CHP) plants

These plants primarily generate heat for industry use. They also generate electricity. We assume they are required to operate at minimum capacity at all times.

Dispatchable (gas, biomass, waste and other thermal)

These plants are relatively flexible and are primarily characterised by their power capacities. Biomass and waste conversion plants have an annual fuel limit applied. Running hour limits, which are binding for some technologies, are not included as inputs in our model. This group includes some plants fitted with carbon capture and storage.

Interconnectors and energy storage

Covered later in the report.

Nuclear

Nuclear plants operate whenever possible. We assume large, traditional nuclear plants are inflexible, operating at an output of at least 90% of their maximum capacity when generating. We assume small modular reactors are more flexible, operating at an output of at least 40% of their maximum capacity when generating.

Summary of generation in Great Britain

Table 3: Summary of generation in Great Britain.

Category	**Renewables** (Wind, solar and tidal*)	**Hydro**	**Reservoir Plants**	**Nuclear**	**Combined Heat and Power (CHP)** (Some biomass, waste and gas plants)	**Dispatchable** (Gas, biomass, waste and other thermal)
Maximum output level	**Yes** Hourly and weather-dependent	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Minimum output level	No	No	No	**Yes**	**Yes**	No
Daily energy limits (upper and lower)	No	**Yes** Weather-dependent	**Yes** Weather-dependent	No	No	No
Stored energy limit	No	No	**Yes**	No	No	No
Annual fuel constraints	No	No	No	No	**Yes** For biomass and waste plants	**Yes** For biomass and waste plants

* Tidal is not modelled as weather-dependent.

= Weather-dependent

Outages and planned maintenance

Unplanned outages

Unplanned plant outages can occur at any time. It is important to understand the impact such outages can have on security of supply.

Our wind and solar profiles already include an allowance for outages, as well as the cut-off wind speed above which turbines cannot operate safely.

For nuclear, CHP, interconnection and dispatchable plants, we model plant failures as occurring randomly and independently of each other. This means that it is possible for an unplanned outage to occur at any time, even if a plant has only just returned to service. For each simulation, we generate a randomly sampled outage pattern for each individual plant. The aggregate impact of these outages across each technology group is then used as an input to our model.

Outages for each technology are characterised by:

- **Duration of outage events** – Fixed for each technology, based on industry insight.
- **Expected annual outage hours (outage rate)** – The estimated number of hours a plant spends in outage each year.

Planned maintenance

Plants can also be unavailable due to planned maintenance activities.

In our model, these events are scheduled before running simulations using a function in PLEXOS that aims to place maintenance periods when margins are not expected to be tight.

We assume one maintenance event per year for each plant to which this applies.

Energy storage

All forms of energy storage can shift surplus clean energy to more expensive periods of typically lower renewable output. Storage also plays an important role in security of supply, storing energy during times of surplus to prevent load loss later.

The FES 2024 report states:

> **Electricity and hydrogen storage are vital to provide the adequacy needed to ensure a reliable whole energy system.**

Great Britain currently has energy storage in the form of batteries and pumped hydro energy storage. However, new technologies including long-duration energy storage and hydrogen have the potential to play a bigger role in future. By considering a mix of storage technologies with different dispatch durations and round-trip efficiencies, we can choose portfolios that best meet the needs of the electricity system.

With the exception of hydrogen (covered in the next section), we model each storage type using the following parameters:

- energy capacity (MWh)
- charging and discharging power rating (MW)
- charging and discharging efficiencies – the proportion of energy lost during the charging and discharging processes
- initial volume of stored energy (MWh)

Storage is also described in terms of:

- **Duration** – defined as energy capacity divided by discharging power rating
- **Round-trip efficiency** – defined as the product of the charging and discharging efficiencies

Any storage technologies that share the same parameters are grouped and modelled as a single store with aggregated energy capacity and power ratings.

Outages are modelled for pumped hydro storage, CAES and LAES.

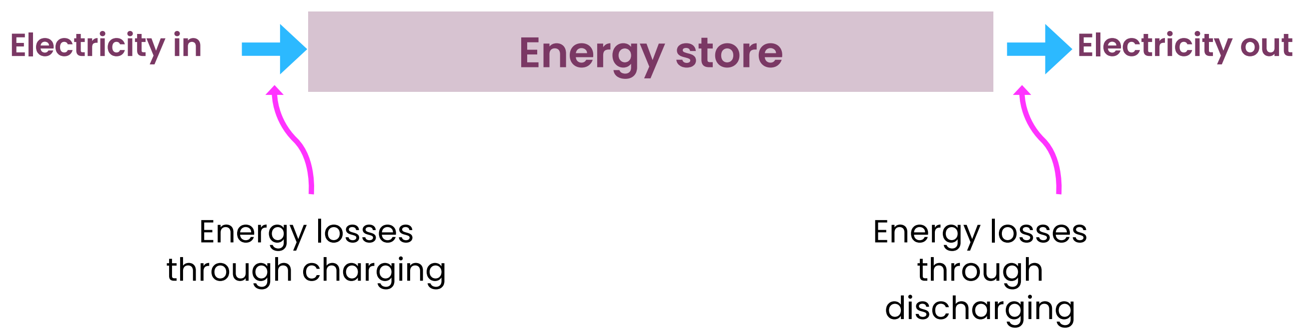


Figure 5: Energy storage and conversion process.

In later sections, we show that our model typically charges energy storage during periods of surplus renewables and discharges stored energy at other times to reduce reliance on other generation. In this way, storage helps to keep lower running costs and carbon emissions. More efficient, shorter duration storage (such as 4-hour batteries) cycles more frequently than less efficient, longer-duration storage (such as CAES and LAES).

Energy storage is also used in our model to proactively support security of supply by holding back some energy as a reserve. This is covered in more detail later in the report.

Hydrogen storage and hydrogen-to-power plants

Some of Great Britain's future electricity needs could be met by hydrogen-fuelled gas turbines. This hydrogen could be produced through electrolysis, steam-methane reformation or imported in liquid form.

Since electrolysis is the only hydrogen production method that affects electricity demand, we assume in our resource adequacy studies that all hydrogen required for electricity production is produced in this way.

For any future scenario that includes hydrogen-to-power capabilities, we assume that hydrogen is produced by electrolysis and stored in underground salt caverns. The stored energy is later used to fuel hydrogen power plants when required.

The parameters used to model these components are:

- storage energy capacity (MWh)
- power ratings for electrolysers and hydrogen-to-power plants (MW)
- conversion rates (or heat rates) – the proportion of energy lost during the two conversion processes
- initial volume of stored energy (MWh)

We do not consider the shared use of hydrogen stores with other industry, although we acknowledge this could have an impact. We also assume that hydrogen can be freely transported from electrolysis sites to storage facilities and from storage to hydrogen-to-power plants.

The 'colour' of hydrogen is not specified in our model. As long as it is produced through electrolysis, we do not differentiate between 'green hydrogen' (electrolysis powered by renewables), 'pink hydrogen' (powered by nuclear) or any other variant.

Outages are modelled for both electrolysers and hydrogen-to-power plants.

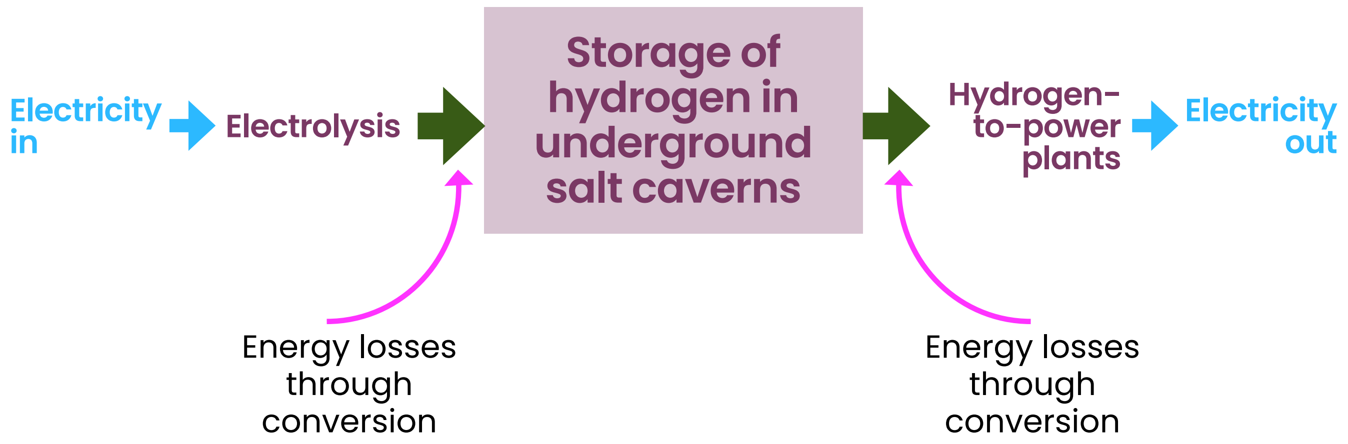


Figure 6: Hydrogen storage and conversion process.

As with other types of storage, our model charges hydrogen storage during periods of surplus renewables and discharges it to reduce reliance on other generation. Due to the low round-trip efficiency of the hydrogen storage process, other storage technologies are typically more economical and are prioritised where possible, subject to maintaining stored energy reserve levels. As a result, we expect hydrogen storage to cycle gradually, potentially on a seasonal basis.

Interconnection

Imports

There are times when imports from Europe may be needed to meet electricity demand in Great Britain. It is important to assess whether sufficient supply will be available in neighbouring markets, including consideration of correlated weather conditions.

To consider this risk, we assess the generation availability in Europe for each hour of historical weather data. From this, we calculate new hourly import capacities, which are then used as model inputs.

This approach captures times when neighbouring European markets may not be able to provide imports to Great Britain without the need for a full pan-European model in every simulation. The significant computational savings from this method enable us to explore more scenarios and stress tests, while improving resource adequacy assessments by considering more plant outage patterns.

A trade-off of this approach is that there may be interactions between energy storage in Great Britain and Europe that are not captured.

Table 4: Interconnection modelling parameters.

Parameters	Interconnection
Import power limit (GW)	**Yes** – Hourly and weather-dependent
Export power limit (GW)	Exports not explicitly modelled

Exports

There may also be times when Great Britain is able to export electricity to Europe. However, we do not model this explicitly and assume that exports would only occur when surplus electricity is available.

Since Great Britain would not typically export to Europe during periods of system stress, we do not expect this assumption to significantly affect our resource adequacy conclusions.

However, there are some scenarios worth highlighting:

- **Low margins in Europe** – In reality, if margins are low in Europe, Great Britain may choose to export electricity from energy storage to support European demand. Our model assumes this energy remains stored in Great Britain.
- **Economic incentives** – In some cases, it may make more economic sense to sell surplus electricity to Europe rather than storing it in Great Britain.

Both scenarios suggest that our modelled storage levels may be overly optimistic. However, we believe the impact on security of supply should be minimal, as our model allows for some level of future foresight, and ensures the maintenance of stored energy reserves when needed. This ensures that storage would not be depleted if doing so would lead to higher risk of shortfalls in Great Britain.

Assessing import availabilities

We have developed a methodology for assessing the availability of energy imports from Europe under different weather conditions.

The process starts with PLEXOS, NESO's pan-European market model of the power system. We scale demand in European countries until they each attain a LOLE of approximately three hours for each future year of interest. This is done without including DSR or interconnection with Great Britain to avoid over-estimating the contributions of these less certain factors. To account for network constraints between countries, we target this LOLE individually for each interconnected neighbour, while treating the rest of Europe as a single region.

Next, we increase demand in Great Britain to ensure it remains in a state of lost load at all times, even when interconnection is available. We also set the Value of Lost Load (VOLL) higher in Europe than in Great Britain, ensuring that when a choice exists, the model always sheds load in Great Britain before Europe.

With these adjustments in place, we run the full dispatch model for each year of historical weather data. Hourly import availabilities can then be read directly from the interconnector flows. Given the high demand in Great Britain, the dispatch model will send as much surplus energy from Europe to Great Britain as possible during each time step. Additionally, the lower VOLL in Great Britain ensures that if both Great Britain and Europe are at risk of lost load, we do not assume imports are available when they might not be.

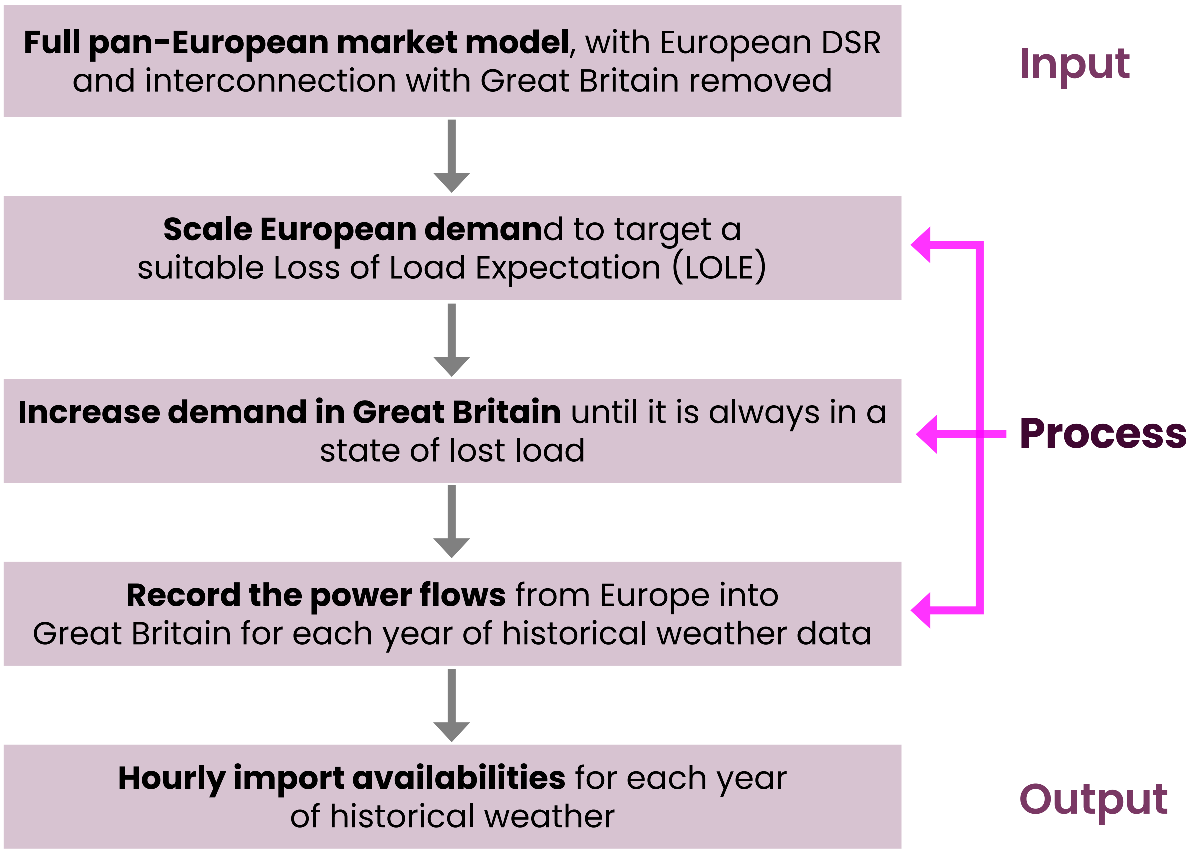


Figure 7: Process for assessing import availabilities.

Dispatch

How the model makes dispatch decisions

Cost optimisation

Our key assumption is that the power system in Great Britain will operate at its lowest expected annual running cost, subject to meeting the intended LOLE level. A high cost is associated with any unserved energy.

This approach represents the most cost-effective solution for consumers, assuming that suitable markets are in place. The model bases its dispatch decisions on this cost optimisation principle.

Since we model categories of technology rather than individual plants, we do not assign different costs to each plant. Additionally, because of our approach to electricity interconnection, we can assess the availability of imports but not hourly European market costs. Instead, we use a broad merit order of costs across the modelled technology categories, which is covered later in the report. As a result, our model may not replicate all dispatch decisions exactly compared to a more detailed market model.

This should not affect security of supply assessments, where we are not concerned with which plant is supplying at a given time, but rather with the timing and volume of potential supply shortfalls. The implications of this approach are discussed in more detail on the following pages.

Limited and rolling foresight

Our model assumes that supply and demand conditions over the course of the year are not perfectly known. Instead, we adopt a rolling horizon approach, which we think better reflects how real-time dispatch decisions would be made.

At each time-step, the model receives a good forecast for the near-term future but a less certain view of longer-term conditions, with this information updated at the start of each modelled day. As a result, dispatch plans are continuously updated as the model progresses through the year. This assumption is particularly important when long-duration energy storage is present in the system, as perfect foresight could lead to an overly optimistic assessment of security of supply.

The foresight in our model is limited as follows:

1. **Short-term foresight** – At the start of each day, the model can perfectly predict two days of hourly supply and demand. This is considered a reasonable timeframe for accurate forecasting, although it can be reviewed in future studies if needed.
2. **Longer-term uncertainty** – Beyond two days, the model can see different possible trajectories for supply and demand, each based on a different possible outage pattern and a different year of historical weather. However, it does not know which trajectory will be realised. This reflects real-world uncertainty, where at the start of the year, we do not know whether winter will be cold or mild, but we do have 34 years of historical weather data to guide expectations.

We use this longer-term information to determine how much reserve energy, if any, should be held back in storage to ensure we meet our intended LOLE level.

The impact of limited and rolling foresight

With energy storage playing a role in our resource mix, dispatch decisions of all technologies need to take into account their longer-term impacts. When foresight is imperfect, this dispatch must consider a range of possible future conditions, minimising the expected average cost over all scenarios. These decisions must also ensure that storage is not depleted ahead of potential deep shortfalls, in line with the intended LOLE level.

Our approach for making dispatch decisions is based on minimising costs over a two-day period of perfect foresight. The first day of the solution defines that day's dispatch decisions, after which the model updates the two-day forecast and progresses to the next day. This is done using the optimisation software PLEXOS.

However, real-time cost optimisation with only two days of foresight would fail to account for long-term storage value, preventing energy storage from being used to its full potential. To address this, we adjust the two-day optimisation problem to incorporate the expected long-term cost impacts of storage actions. Every time energy is placed into storage, it carries both a real-time cost and a long-term value. Later sections explain how storage costs have been adjusted in the model to reflect this.

We have also recognised that, when forecasts are uncertain, energy reserves may need to be held in storage. Without sufficient reserves, there may not be enough power to cover expected shortfalls. Our approach involves calculating the reserve levels needed to meet the LOLE target and applying a high penalty for failing to meet these reserves at the end of each two-day look-ahead period. This method is described further in later sections.

Our methodology is inspired by Dynamic Programming, which considers how different actions taken today affect the future state of the system. A key advantage of this approach is that dispatch decisions are continuously updated based on an evolving view of future conditions. Although our current implementation is relatively simple, we may explore enhancements in future work.

Modelled running costs

A merit-order approach

There is a high degree of uncertainty in operating and fuel costs over the long-term timescales that we are considering. This uncertainty is particularly relevant for imports, as the future development of the European power system is unknown. To account for this, we use a broad ordering of costs, as shown in Figure 8.

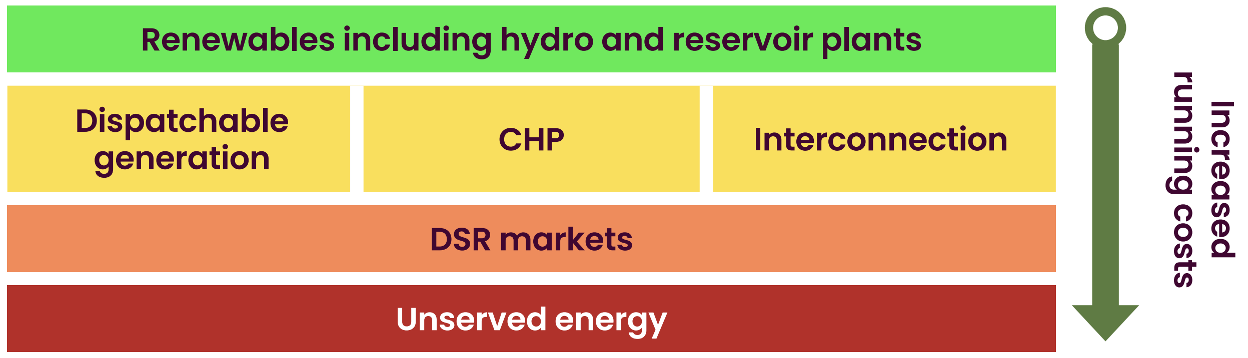


Figure 8: Merit order of generation and demand resources.

We also include operating costs for nuclear generation, though these do not affect outcomes as nuclear is considered must-run. Dynamic demand-shifting is assumed to have no running costs.

To reduce the risk of water depletion in reservoir plants, we assign them a slightly higher cost than other renewables. Similarly, biomass and waste-conversion plants have an annual fuel availability constraint. In our investigations so far, this fuel allowance has been more than sufficient, provided biomass and waste plants are used alongside other dispatchable plants. If, in future studies, we observe that the fuel constraint becomes a limiting factor, then we will assign these plants a slightly higher cost than others in the same category to reduce the risk of fuel shortages.

Storage costs

We assume that storage has no real-time running costs. However, in the model, a cost is applied each time a unit of power is charged into or discharged from a store. These costs are designed to reflect the long-term changes in expected value resulting from each storage action.

A negative cost per MWh is applied when storage is charging, reflecting the long-term expected benefit of storing energy. Conversely, a positive cost is applied for discharging, as this action results in a decrease in long-term value.

The cost structure is carefully designed to ensure that:

- storage charges when there is a surplus of generation from renewable and committed plants
- storage discharges to reduce reliance on other forms of generation or interconnection generation
- subject to maintaining reserve levels, the most efficient storage technologies are deployed first, minimising energy losses

Our approach to storage operation is considered reasonable, though it could be refined in future studies. In reality, there may be times when imported electricity is so cheap that it is preferable to charge storage with energy from Europe. Similarly, there may be cases where exporting stored energy to Europe would be economically beneficial.

These trade-offs are covered in more detail later in the report, along with a fuller explanation of storage dispatch decisions.

Energy storage dispatch

As a result of the modelling decisions and running costs outlined in previous sections, energy storage dispatch operates in two distinct ways:

- **Arbitrage** – Storage charges when surplus renewables are available and discharges to replace other forms of generation.
- **Stored energy reserves** – Some storage may hold back energy for unforeseen periods of system stress. This is a natural consequence of imperfect foresight and helps mitigate the risk of deep shortfalls.

The reserve level is calculated for different types of storage and introduced as a soft constraint (with a high penalty) at the end of the two-day optimisation period. It can only be overridden if load would otherwise be lost or if DSR would need to be used. DSR is treated as a last resort to ensure that the system remains secure without excessive reliance on consumer participation that may be uncertain.

To determine the appropriate reserve level, we iteratively run the dispatch model with different candidate reserve levels until we reach the minimum level that ensures the LOLE target is met. Ideally, if a larger dataset of weather conditions were available, we might carry out this exercise using a subset of data as a training set. However, given the limited sample size of 34 years of historical weather data, we instead use the entire dataset for this purpose.

A potential improvement to this approach would be to allow the reserve level to vary over time, perhaps seasonally. This would enable the model to update long-term expectations as the year progresses. However, for now, we take a more conservative approach, assuming that this information is not available.

The assumptions underpinning these decisions could be challenged, with interconnection being the clearest example. Our model does not currently account for hourly variations in import and export costs. If it did, the model might:

- charge storage using imported energy when costs are low
- discharge storage instead of importing energy when import costs are high
- sell stored energy to Europe rather than storing it, when the price differential between interconnection and other generation makes it economically beneficial

Each of these scenarios could affect security of supply assessments and introduce uncertainty in our modelling. However, maintaining stored energy reserve levels would ensure that the minimum security of supply standard is still met.

Finally, when storage is required to prevent shortfalls, there is often a choice of how to do this, with each option yielding the same EEU but potentially different LOLE outcomes. As a default, we assume that stores discharge only the energy needed for the first period of the event before moving onto the next period, and so on. This strategy requires the least foresight, making it a practical and reliable approach. However, we will also explore the impact of alternative strategies. On balance we consider our approach reasonable given the complexity and uncertainty involved.

The dispatch order

Dispatch decisions are made daily, minimising long-term and short-term costs over a two-day period, while only taking the solution from the first day. Once all costs and parameters have been set for the model, the optimisation software generates the solutions. However, a deeper understanding of these solutions is useful, so we outline the expected dispatch order below.

steps

1

Meet demand using must-run generation, including nuclear and combined heat and power (CHP), at its minimum power requirement, alongside available renewable generation. If demand is fully met and stored energy reserves are maintained at the end of the two-day period, proceed to Step 6.

2

If demand is still not met, use dynamic demand-shifting, provided this does not create a new shortfall elsewhere. If demand is fully met and stored energy reserves are maintained at the end of the two-day period, proceed to Step 6.

3

If demand remains unmet, discharge energy storage in order of round-trip efficiency, ensuring that this does not cause new shortfalls or violate stored energy reserve constraints. Dynamic demand-shifting actions may be rearranged at this step to co-optimise with energy storage. If demand is fully met and stored energy reserves are maintained at the end of the two-day period, proceed to Step 6.

4

Use interconnection and dispatchable generation to fill any remaining supply gaps and charge storage if needed to maintain reserve levels. Storage and dynamic demand-shifting actions may again be rearranged to improve the solution, for example charging storage via interconnection or dispatchable generation to prevent future shortfalls. If demand is fully met and stored energy reserves are maintained at the end of the two-day period, proceed to Step 6.

5

If shortfalls remain, use stored energy reserves to meet demand. If supply shortfalls persist, activate demand-side response markets to minimise unserved energy.

6

If, at this stage, surplus renewable or committed generation is available over the two days, it is stored in energy storage in order of decreasing round-trip efficiency.

At this point, demand has been met as much as possible. This determines the solutions for the entire day. The process then moves forward to the next day, repeating from Step 1.

Outputs

Outputs of the model

Security of supply metrics

The standard security of supply metrics used in our analysis are LOLE and EEU. These metrics are calculated for any given year and portfolio by running the dispatch model multiple times across all years of historical weather data and many randomly selected outage patterns.

- LOLE represents the average number of hours of supply shortfall per year.
- EEU measures the average volume of unserved energy across all simulations.

We will also present security of supply in other ways to provide additional insights into the underlying risk profiles, as well as the drivers and nature of potential stress events.

For example, in our *Spotlight on Security of Supply Metrics*, we highlighted the advantages of using weather-conditional metrics. Instead of averaging across all years of historical weather data, each security of supply metric is assessed individually against each year. This provides a clearer understanding of how shortfall risks vary with different weather patterns. Since our model has a quick run-time, we can accurately calculate weather-conditional metrics, allowing for a deeper understanding of the underlying drivers of risk.

Unserved energy events

Our model allows us to identify the underlying drivers of potential supply shortfalls. It also provides insight into how different portfolios of resources may behave under stress events and whether they are particularly vulnerable to specific risks.

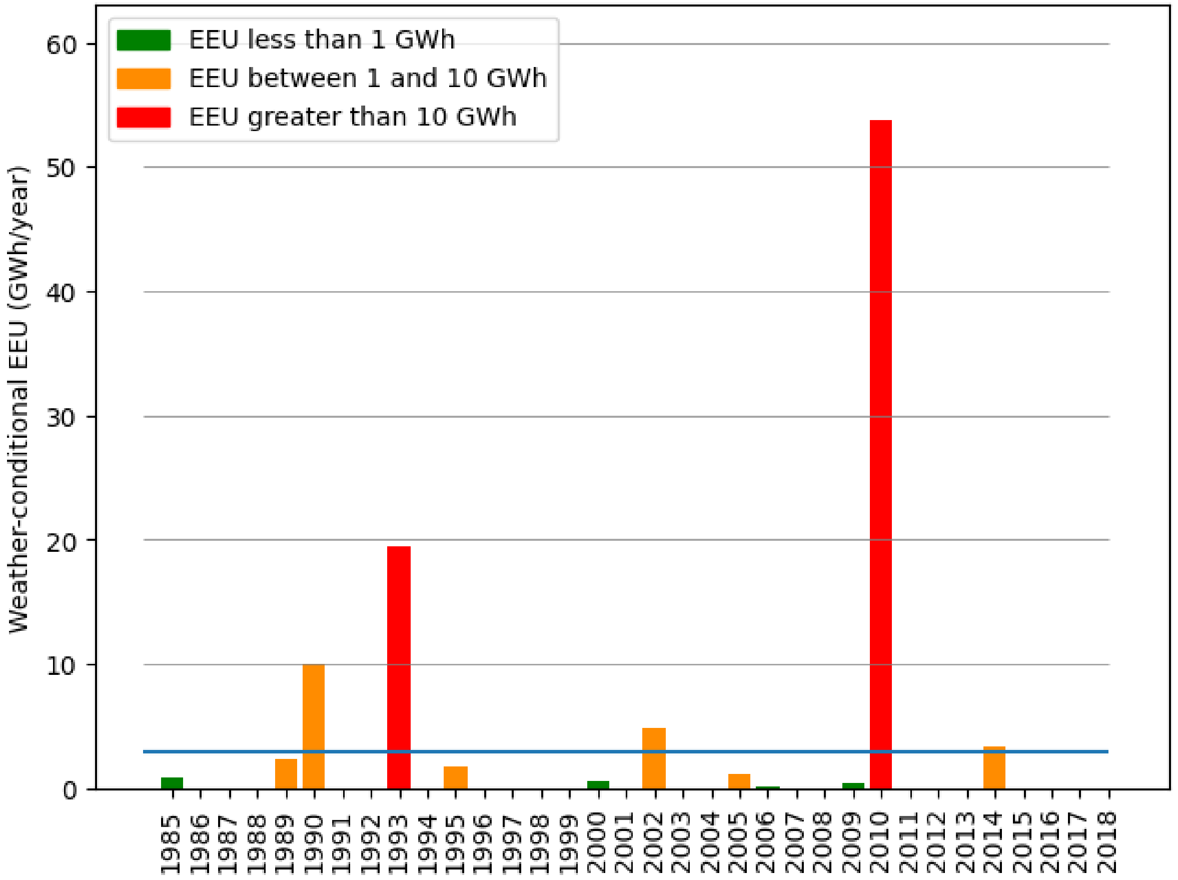


Figure 9: Illustrative example, taken from our *Spotlight on Security of Supply Metrics*, showing the variation of risk for a 2023/24 power system across different years of historical weather. The 'weather-conditional EEU' is the average volume of unserved energy, for a given year of weather data, across all simulations of randomly drawn plant outages.

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