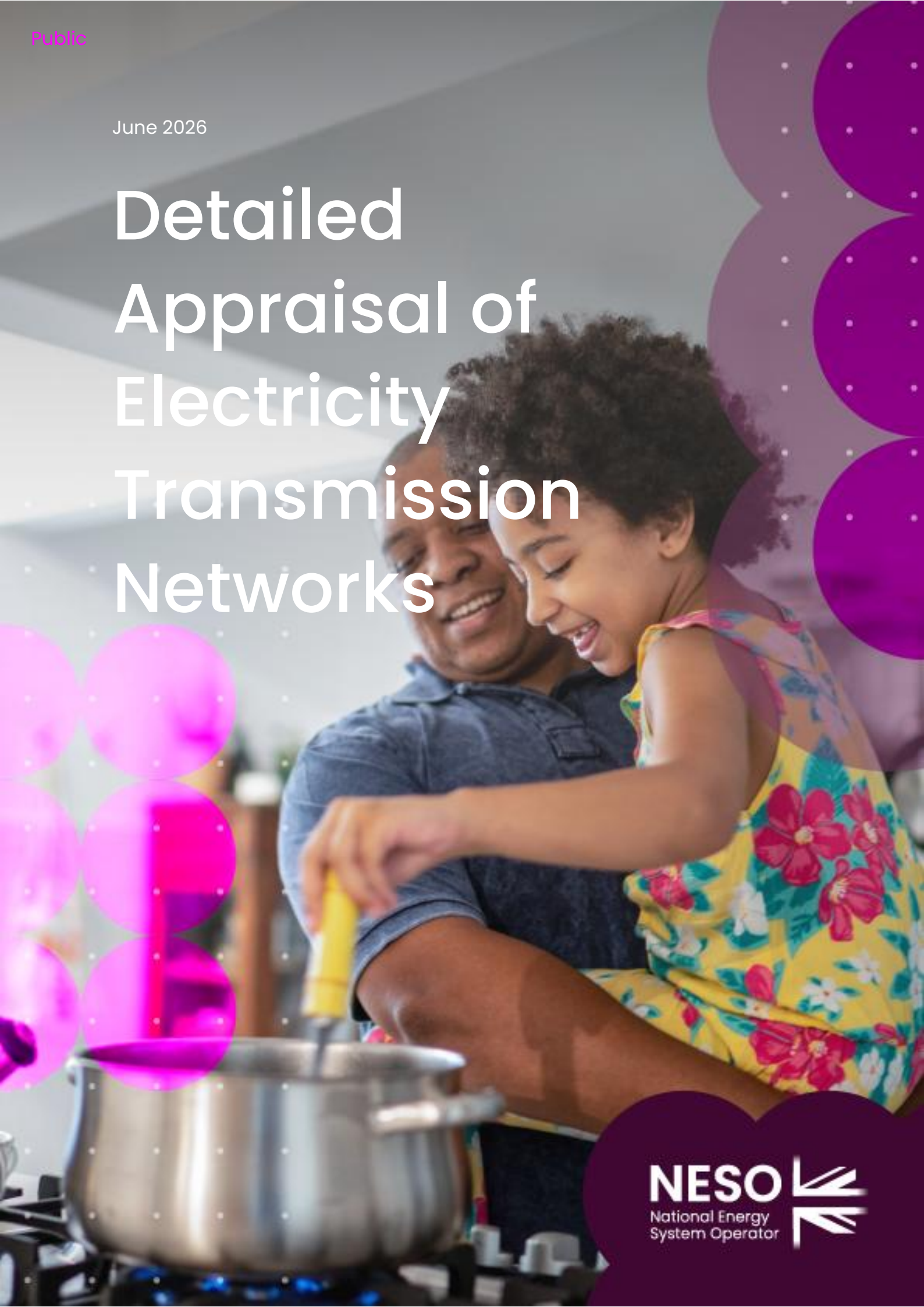
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June 2026

Detailed Appraisal of Electricity Transmission Networks



NESO
National Energy System Operator

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What this document covers

This detailed appraisal of electricity transmission networks explains what could drive decisions, and what different technology choices might mean in reality. It can also be read alongside the Electricity Transmission Design Principles, which give more detail and rationale for design choices as infrastructure goes through stages of development.[1]

- Sections 1 and 2 explain how the electricity transmission network operates and the key players involved in the electricity system. These sections introduce the main components of the electricity network and the different organisations involved.
- Section 3 dives deeper into why new electricity infrastructure is needed. It sets out the key drivers for network investment, including government targets, new connections, electrification and the need to maintain and replace ageing assets.
- Section 4 describes how decisions are made about new network solutions. It explains how future needs are identified and how different options are developed and assessed. It also considers the fine balances and decisions involved between cost, deliverability, environmental impact and system performance.
- Section 5 takes a closer look at specific technology choices, such as onshore versus offshore routes, overhead lines versus underground cables, and different substation technologies.

Further information

Footnotes in the document include external references to more specific information that is beyond the scope of this document. There are also text boxes titled 'Survey finding' throughout the document. In May 2026, we commissioned an independent survey of 2,020 electricity bill payers and industry stakeholders. The survey sought to discover more about people's attitudes towards, and knowledge of, the electricity transmission network. The boxes highlight specific findings from that survey that are relevant to the topic being discussed.

1 Electricity Transmission Design Principles (2025)

1. Key elements of the electricity transmission network



Generators produce our electrical energy

There are several types of generators – including large gas-fired power stations, nuclear plants and renewable sources, such as offshore and onshore wind farms, solar farms and hydroelectric schemes – in Great Britain.

Electricity is typically generated at voltages in the range of 11–25 kV before being transformed up to the 275 kV or 400 kV transmission voltage (and 132 kV in Scotland). In recent years, generation in Great Britain has become increasingly decentralised, with many smaller generators connecting directly into distribution networks rather than into the high-voltage transmission system.

Power, voltage and current

Electrical power (measured in watts, W, or kilowatts, kW) is defined as the rate at which electrical energy is transferred or consumed. Electrical energy is measured over time in watt-hours (Wh) or kilowatt-hours (kWh). A typical electric heater is rated at about 2 kW, which is the rate it uses electrical energy when switched on. If the heater was run for an hour, it would consume 2 kWh of energy. If used for half an hour, it would consume 1 kWh of energy. This rate of energy use depends on its voltage (volts, or V) and the flow of current (amperes, or A) of the electricity.

As an analogy – remember, analogies are always imperfect – imagine a water pipe feeding a fountain in a pond. The water pressure in the pipe is equivalent to electrical voltage. The water delivered along the pipe is equivalent to electrical current. The amount of water at a given pressure able to flow through the fountain every hour (buckets per hour) is equivalent to the electrical power (kW). The total amount of water collected in the pond at the end of the day (buckets) is equivalent to the total electrical energy used (kWh). So, a higher water pressure (equivalent to higher electrical voltage) delivers more water every hour (equivalent to more electrical power and more delivered energy).

Putting down the bucket, then, and getting back to electricity, it may now be a little easier to see why the transmission network needs to transmit a huge amount of voltage for the relatively small amount of voltage needed in people's homes and businesses. The voltage in your sockets at home only needs to be around 230 V to deliver the energy you use. The voltage in the transmission network needs to be more than 1,000 times higher (typically 400,000 V) to deliver the bulk of power needed by our towns and cities.

Transmission and distribution networks transport the electricity

Great Britain's electricity network has two complementary parts that work together to move electricity safely, reliably and economically, while minimising disruption to communities and the environment.

Transmission: The motorways of the grid

The transmission network (or 'grid') moves very large quantities of electricity over long distances across the country, from areas of generation to areas of demand. Think of it as the national motorway network, with high-capacity routes designed for moving large volumes efficiently.

This efficiency is achieved through the use of very high voltages. The reason for this comes down to how electricity behaves. When electrical current flows through a conductor, it generates heat, which is wasted energy. If we try to push more power through a conductor by doubling the current, this quadruples the energy lost to heat, making high current a costly way to move power.

We can instead transmit more power by increasing the voltage. We know that power equals the current multiplied by the voltage, and so if we cannot increase the current, we can increase the voltage to either transmit more power, or transmit the same power at a lower current, and therefore lower energy wasted as heat.

Great Britain's transmission network spans over 9,500 km, operating primarily at voltages of 132 kV in Scotland, and 275 kV and 400 kV across Great Britain.

Distribution: The local roads of the grid

Whereas transmission moves electricity in bulk across the country, distribution delivers it in smaller amounts to millions of homes and businesses. Think of it as a series of A and B roads. Most appliances in homes and businesses are designed to run on low voltages. That is why its voltage is reduced (or 'stepped down') by transformers before it reaches us, making it safe and suitable for everyday use. As a result, distribution networks are far more geographically widespread than the transmission system.

Because the distribution network is less about transmitting electricity in bulk, it operates at lower voltages than the transmission network. However, it is increasingly carrying electricity from smaller generators, such as solar panels and small onshore wind farms, connected directly at this level.

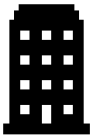
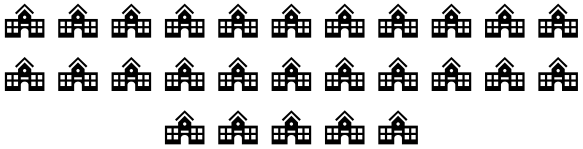
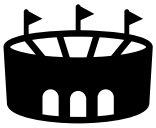
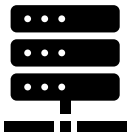
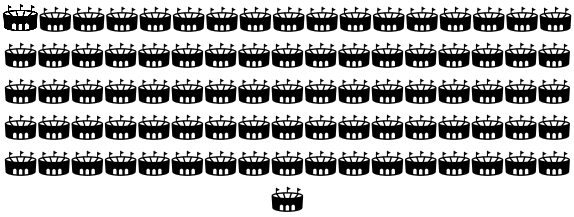
Different customers in the distribution network are connected at different voltage levels:

- starting at 132 kV in England and Wales for the largest industries and data centres

- stepping down through 33 kV and 11 kV (for large office blocks, hotels and light industry)
- before finally reaching 230 V for small offices, commerce and domestic premises

This document focuses primarily on the transmission network. Table 1.1 describes several distribution assets to illustrate some of the differences between the two designations.

Table 1.1 Power use comparison between different physical components of the grid

Consumer	Typical power rating	Equivalent to approximately…
 UK household	14–24 kW, (1–1.5 kW when averaged between all the households in the street)	
 Medium-sized UK school	20–35 kW	18 houses 
 20-storey high-rise office	500–1,000 kW (or 0.5–1.0 megawatts, or MW)	27 schools 
 Large (70,000+ spectators) UK football stadium	4,000–10,000 kW (or 4–10 MW) during a game	9 office blocks 
 Hyperscale data centre	200,000 kW (or 200 MW) to 1,000,000 kW (or 1 gigawatt, GW)	86 stadiums 
 Transmission line capacity (400 kV double circuit)	2,500,000–7,500,000 kW (or 2.5–7.5 GW)	8 data centres 

The physical assets of the electricity supply system

This section describes the structure of the electricity system and explains the purpose and appearance of the key physical assets within it. The electricity network is made up of substations, and circuits for transmission and distribution. Section 5 explores these assets in more detail.

The electricity supply system

The transmission network of Great Britain consists of over 460 (400 kV or 275 kV) substations, all connected by a network of high-voltage circuits running over some 9,500 km of transmission routes.

The transmission network supports all sectors of the economy and all the communities of Great Britain. The transmission system must operate with a very high level of reliability for consumers. To minimise the impact of any component failure, it is carefully designed with control, protection and monitoring systems. It also has redundancy in key network components to provide contingency in the event of a fault on one of the circuits. This is one of the reasons most British transmission routes comprise two circuits built in parallel rather than just one. The Security and Quality of Supply Standard (SQSS) sets out the strict safety standards that transmission owners (TOs) must adhere to.[2]

The bulk of these routes comprise 400 kV or 275 kV overhead lines (OHLs), supported by steel lattice pylons. In Scotland, however, 132 kV circuits are also classified as transmission rather than distribution, and some of these are supported by wooden poles instead of steel lattice pylons. Transmission circuits may also include some underground sections, (for example through urban environments).

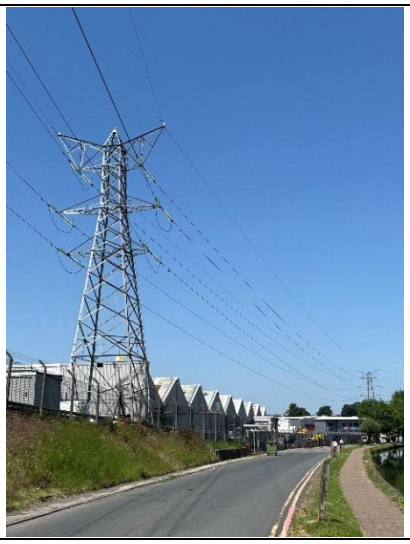
In some instances, circuits are installed partially offshore. In these cases, onshore infrastructure is still required to connect both ends of the offshore cable to substations, including converter stations at each end of the link.

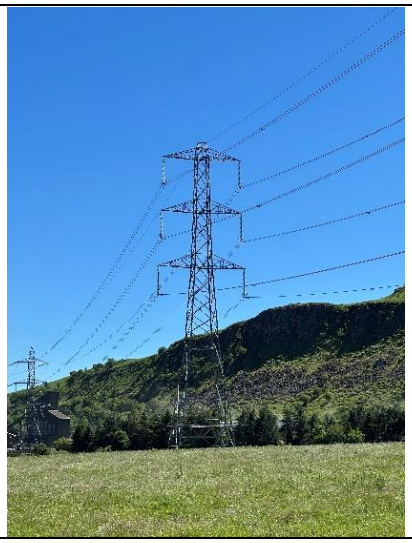
Overhead lines and underground cables

Overhead lines (OHLs) and underground cables (UGCs) are collectively known as 'linear assets'. They are the physical structures that carry electricity between substations. These assets include OHLs supported by towers (commonly referred to as 'pylons') or poles, as well as underground and subsea cables. OHLs are commonly used in rural areas because they are cheaper and easier to maintain. UGCs are widely used in urban environments and some environmentally sensitive locations (if appropriate), despite their higher cost and complexity. Each technology's technical limitations influence which is better in a

2 Security and Quality of Supply Standard (2026)

given scenario. The size and appearance of these assets are determined by the voltage level and power capacity of the circuit.

Transmission overhead lines	Distribution overhead lines
Transmission OHLs are the most visible part of Great Britain's electricity grid. Steel lattice pylons or monopole steel structures (known as 'T-pylons') suspend the high-voltage conductors safely above ground using porcelain or glass insulator strings (Figure 1.1). Transmission routes usually accommodate two parallel circuits. This design provides operational flexibility and enables maintenance and unplanned outages to be managed without interrupting supply. It also helps to reduce energy losses.	Distribution OHLs are typically supported by smaller steel lattice towers or wooden poles. They are shorter and more closely spaced than transmission towers. Unlike transmission circuits, distribution networks branch extensively to reach individual customers.
	
400 kV OHL route (2 circuits)	**132 kV lattice tower (2 circuits, England and Wales only)**



275 kV OHL route (2 circuits)



33 kV wood pole (single circuit, Scotland) OHL route

Figure 1.1: Examples of OHLs

Underground cables

UGCs are typically used in towns, cities and some sensitive landscapes, such as coastal areas (Figure 1.2). They reduce visual impact and provide additional protection against damage. However, they are more expensive and complex to install, maintain and repair than OHLs. Although their visual and general impact on the landscape is less than OHLs', UGCs have a greater impact on the environment and communities during the construction phase.



Figure 1.2: Example of an underground cable. Source: National Grid

The cables need to be separated from each other to enable heat dissipation. This requires significant earthworks along the cable construction corridor (Figure 1.3). This corridor can often be more than 100 m wide. It usually contains 12 or more individual cables.

Distribution UGCs are generally used in towns and cities, but increasingly also in rural or other sensitive environments. Like any electric cable, they generate heat as the current flows in them. The cables are housed in narrow trenches, which limits their number. To keep the current below the design levels, to control heat loss, each cable can only serve a limited number of properties.



Figure 1.3: Example of a route corridor, showing UGCs. Source: National Grid

Subsea cables

Subsea cables are used when electricity needs to be transmitted offshore, or when this is more practical than onshore alternatives. For example, they are used to:

- connect offshore wind farms
- link Great Britain to other countries (via 'interconnectors')
- connect islands to the mainland
- connect widely separated points on the onshore network – aiding power transfer from North to South

The short lengths (up to about 80 km) of offshore alternating current (AC) cables can be connected directly to the 400 kV AC network. This can be increased to 150 km if additional compensation is installed. Longer cable routes require high-voltage direct current (HVDC) technology to be used instead. An important aspect of using HVDC is the need to build AC–DC converter stations.

Substations

Substations are the key connection points within the transmission network. They are present at all voltage levels and, at the transmission level, perform several key functions, including:

- connecting generator customers and 'stepping up' (increasing) their voltage to the transmission network level using transformers
- 'stepping down' (decreasing) the transmission network voltage using transformers
- connecting large-demand customers (for example distribution networks, heavy industry, interconnectors and railway supplies)
- accommodating and connecting network power factor compensation equipment, which maintains the stability of the transmission system
- providing network operators with the flexibility they need for maintenance by allowing parts of the network to be switched in or out of service
- monitoring the health of the network
- quickly switching out of service any network component that develops a fault

Although substations may look similar, their size and housing depend on their location and intended purpose. When connected to the transmission system, generation substations step voltage up to very high levels so that electricity can be transmitted efficiently over long distances. Transmission substations interconnect major circuits and reduce (step down) the voltage to levels suitable for distribution networks. This is further reduced in stages by smaller distribution substations until it is safe for domestic and commercial use.

Substations are designed based on the type of switchgear they are using. Switchgear comprises the components responsible for controlling and protecting the network. Substations are typically either installed outdoors or indoors, and may house either air-insulted switchgear (AIS) or gas-insulated switchgear (GIS). Both enclosure options and both insulation technologies have their advantages. Outdoor AIS can often be the economic choice for new substation designs. However, the key benefit of GIS (that it has a smaller footprint than AIS) means it can, in some cases, offer a more economic and efficient solution.

Converter stations

Wherever HVDC is used instead of AC, a converter station is needed to convert between the two types of electricity. In Great Britain, the choice to use HVDC is usually made when transporting electricity over long-distance subsea routes, including:

- for interconnectors that connect Great Britain to other countries
- for offshore transmission connections to other parts of Great Britain (for example from Scotland to England or the Shetland Islands)

- for distant offshore wind generator connections

Converter stations are often large warehouse-size structures, typically located on or near the coast (Figure 1.4). A converter is sited at each end of the connection. Local community and environmental impacts need to be considered when siting. Each converter station houses advanced power electronic equipment, cooling systems and protection systems. The first station converts the AC electricity coming from a nearby AC substation to DC electricity. It also controls the flow and quality of this electricity being transmitted via the offshore HVDC cable. At the far end of the link, a second converter station 'inverts' the DC back to AC before feeding it into the nearby grid substation.

The converters can control the flow of power in either direction along their HVDC link. The voltage source converter (VSC) station can also help control power flows in other, parallel, parts of the wider electricity system.



Figure 1.4: A 320 kV HVDC converter station. Source: National Grid

2. Responsibility and accountability for planning and building electricity networks



The role of the system operator

NESO is an independent public corporation responsible for the operation and strategic planning of Great Britain's energy system.

We operate today's electricity system and design tomorrow's energy system. Every second of the day, NESO runs the electricity transmission system in real time. We balance supply and demand to keep power flowing safely and securely to homes and businesses.

Alongside this, we take a long-term view. We plan how the electricity network, and the wider energy system, needs to evolve to support decarbonisation, maintain security of supply and strengthen resilience.

We also coordinate across electricity and gas to manage resilience and emergencies. We develop energy markets, manage network connections and procure the services needed to keep the system stable. In doing so, we provide independent technical and strategic advice to the UK and devolved governments, the regulator and industry.

The infrastructure is owned and managed by private companies

These organisations build and operate the various physical components of the network to deliver power – from generation to transmission, distribution and eventually to the consumer (Figure 2.1). All parties are regulated. Network companies operate under comprehensive licence obligations.

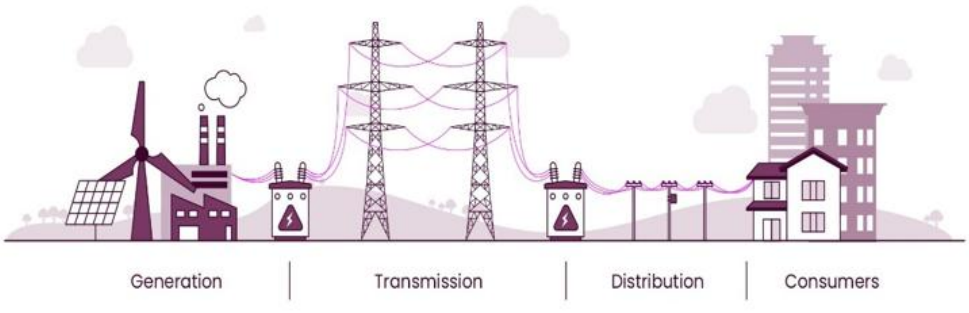


Figure 2.1: The relationships between generation, transmission, distribution and consumers

Transmission owners

Transmission owners (TOs) build, own and maintain Great Britain's main interconnected high-voltage electricity transmission network. They are responsible for designing, developing and delivering network reinforcements, maintaining assets and ensuring the

physical capability of the system. They earn regulated revenue and return on investment, determined by the regulator, the Office for Gas and Electricity Markets (Ofgem). This income is recovered through network charges. TOs do not operate the electricity system in real time.

There are three TOs in Great Britain. Each manages a different geographical part of the transmission network (Figure 2.2):

- National Grid Electricity Transmission (NGET)
- SP Energy Networks (SPEN)
- Scottish and Southern Electricity Networks Transmission (SSEN-T)

In the future, Ofgem intends to introduce competition into the ownership of new elements of the transmission network. When this occurs, the new companies working alongside the three incumbent TOs will be known as 'competitively appointed transmission owners' (or CATOs).

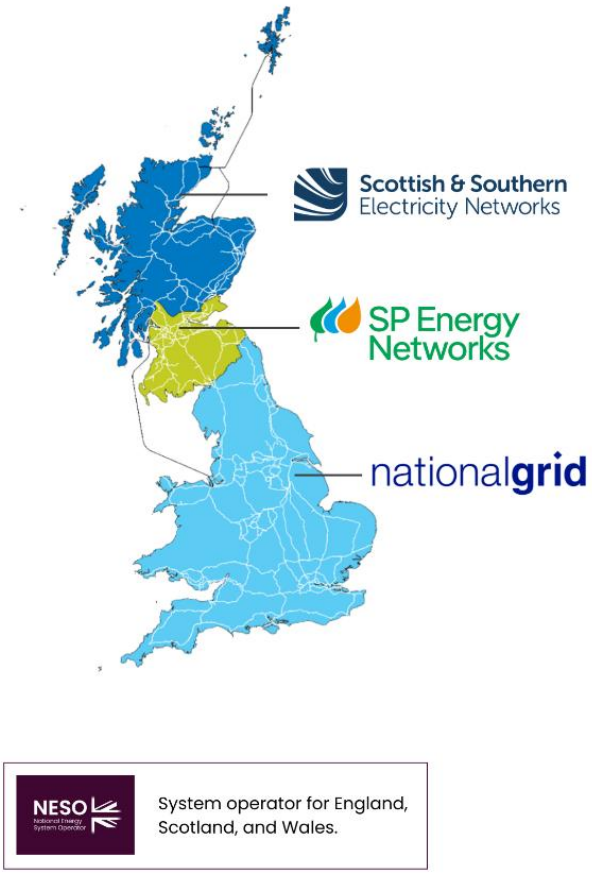


Figure 2.2: Map of transmission ownership in Great Britain

Onshore

Distribution network operators (DNOs) own and operate the local electricity networks that deliver power to homes, businesses and most industries. Their revenues and return on

investment are regulated by Ofgem and recovered through network charges. The DNOs also provide connections to the many smaller onshore generators, mostly wind farms and solar farms. Typically, such generators with outputs of less than about 50 MW would be connected to the distribution network at 11 kV or 33 kV rather than directly to the transmission network. However, the exact connection arrangements for any small generator depend on the capacity available at the desired distribution network connection point.

As the distribution networks take on more generation connections, they become less passive. This is because the power always flows one way, from the transmission network to consumers. It also means they become more active and complex. For this reason, DNOs increasingly need to develop a secondary role alongside that of traditional network owner, namely distribution system operator (DSO). DSOs must manage system planning, local flexibility and distributed energy resources to maximise the network benefits for consumers and generators. They must also avoid network overloads.

There are six DNOs in Great Britain. Each manages a different part of the distribution network:

- SP Electricity North West (SPENW)
- Northern Powergrid (NPG)
- Scottish and Southern Electricity Networks Distribution (SSEN-D)
- SP Energy Networks (SPEN)
- UK Power Networks (UKPN)
- National Grid Electricity Distribution (NGED)

Offshore

Offshore transmission owners (OFTOs) own and operate the transmission assets that connect offshore wind farms to the onshore grid. These assets are primarily offshore, but some elements are located onshore. They are appointed through competitive tender processes run by Ofgem, normally after the wind farm developer has finished building the transmission assets. The OFTO is responsible for financing, maintaining and operating these assets over its licence period. An example of this would be the Hornsea Two offshore wind farm. Here, the offshore developer originally built the offshore wind farm and the link to the onshore network. Following a competitive tender, the developer sold the offshore transmission element to an OFTO for them to operate and maintain.

Interconnectors are high-voltage electricity links between Great Britain and neighbouring electricity systems in other countries. Private developers own and operate them. Their role is to enable cross-border electricity trading, which can improve the security of supply and reduce costs. As Great Britain is an island, all the interconnectors must be built using subsea cables. Interconnectors operate commercially but within a regulatory framework set by Ofgem and international agreements.

Policy and regulation

Equally as important as the physical infrastructure of electricity networks are the governance structures which regulate the organisations participating in the electricity system.

The regulator

Ofgem (the Office of Gas and Electricity Markets) is a non-ministerial government department that acts as the economic regulator of the electricity sector in Great Britain. It protects consumer interests by regulating energy companies, including determining regulatory funding for network companies. Regulation sets limits and standards on companies where there is not enough competition to create those limits 'naturally'.

Governments

The UK Government, through the Department for Energy Security and Net Zero (DESNZ), determines overall energy policy, targets and the legislative framework set by the UK Parliament. The Scottish and Welsh Governments determine policy in areas of devolved responsibility.

Permissions

The Planning Inspectorate in England and Wales and the Energy Consents Unit in Scotland process consent applications for major transmission projects, including considering environmental and community impacts. In certain circumstances, some projects (typically substations and onshore converter stations) which fall under relevant Town & Country Planning legislation are decided by the Local Planning Authority. The exact method to gain consent depends on the type of infrastructure being proposed. In general, for transmission infrastructure these organisations make recommendations to the relevant decision-making authority (Secretary of State for England and Wales and Scottish Ministers in Scotland). They then make the final decision on whether a project receives consent to proceed.

3. Drivers for new electricity infrastructure



Long-term trends and government policy influence grid investment needs

Energy use across Great Britain is changing. For decades, electricity demand has been falling. It is now expected to double by 2050. New network investment is needed to connect new customers and respond to where electricity is increasingly generated and used. This investment is vital to support economic growth, jobs and future industries.

Long-term trends are driving this change. These include population growth; the falling costs of renewables, electric vehicles and heat pumps; industrial decarbonisation; and the expansion of high-energy data centres. Together, these shifts are increasing pressure on the grid and mean it must continue to develop to provide resilient, clean and affordable power.

The geographical distribution of energy resources and demand across Great Britain is a key driver of transmission network development. There are abundant wind energy resources in Scotland, and major demand centres are concentrated in England. As a result, there is a growing requirement to expand transmission infrastructure to connect generation and demand across the country.

Government is also important. It can often speed up or slow down these underlying trends, for example by introducing subsidies, taxes or new policies. In 2019, the UK Government set a legally binding target to reach net zero by 2050. In 2024, it set an ambition for at least 95% of Great Britain's electricity generation to come from low-carbon sources by 2030. The UK Government enacted policies to help achieve these objectives. These included:

- having 100% of new cars and vans sold being zero emission from 2035
- the Boiler Upgrade Scheme, which provides grants for electric heating
- laws aiming to improve the energy efficiency of appliances and buildings

These policies have a direct impact on demand levels for electricity. Figure 3.1 and Figure 3.2 outline historic and predicted energy consumption in the UK.

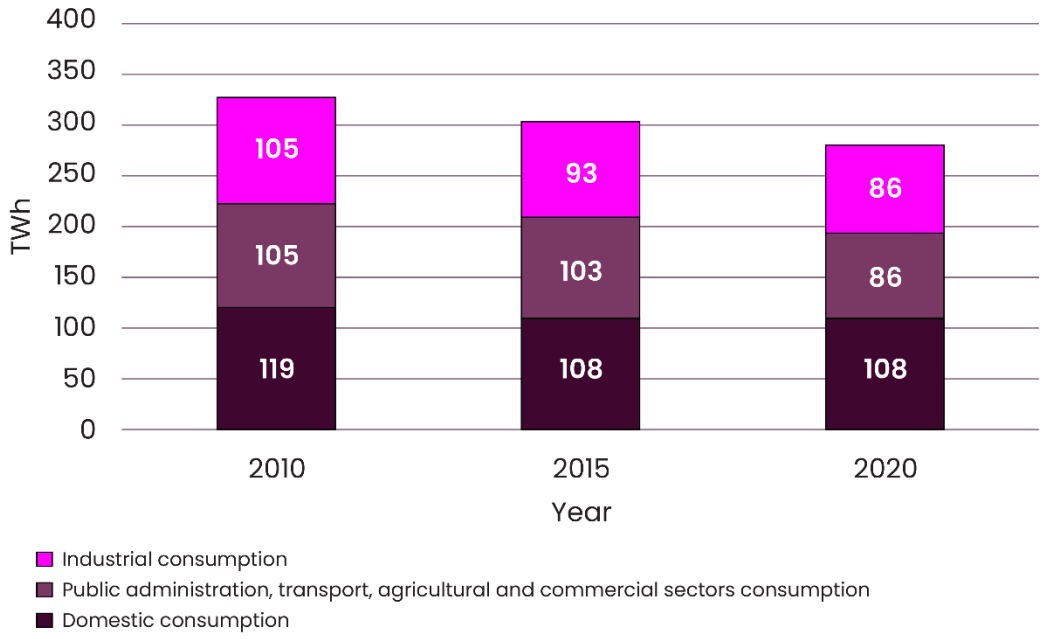


Figure 3.1: UK electricity consumption 2010–2020. Source: DESNZ

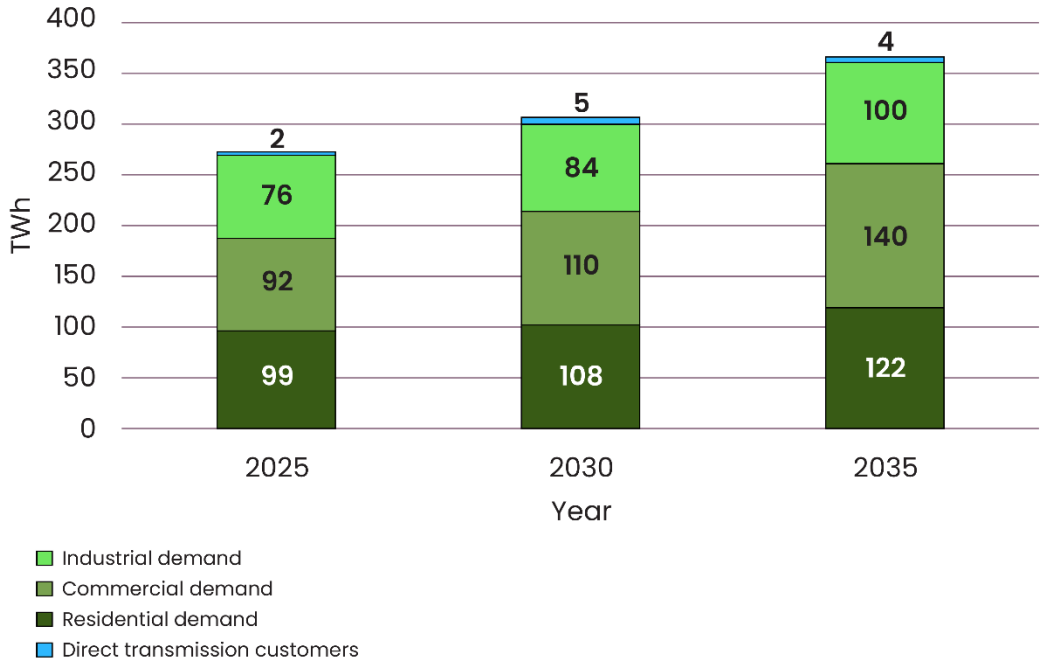


Figure 3.2: Great Britain's forecasted electricity consumption 2025–2035. Source: NESO

New connections

When a new connection is requested, the process is delivered jointly, with clear roles across NESO, the network companies and the connecting customer.

From individual requests to system impacts

First of all, network companies assess whether the existing network has sufficient power to accommodate the additional power flows. If it does not, reinforcement or new infrastructure may be required.

Because the electricity system is interconnected, the impact of a new connection is often not local. A single project can trigger the need for multiple upgrades across the network, particularly where power flows across constrained boundaries or over long distances.

NESO coordinates the overall connections process. It manages applications and the pipeline, carries out system-wide assessments and issues the connection offer in conjunction with the relevant network company.

All projects seeking to connect are placed into a process that determines the order in which they are assessed and offered connections. NESO and the TOs use detailed system studies and network models to understand how projects in the pipeline will affect the transmission system in a range of future scenarios. These studies inform decisions on sequencing, required reinforcements and which projects can progress efficiently. We make sure this is in line with system needs and strategic priorities - set by the UK Government and overseen by Ofgem.[3]

This process used to be on a 'first come, first served' basis, which worked when volumes were lower (Figure 3.3). Now that there are many more connection requests, we have introduced a more coordinated approach to ensure the right projects progress at the right time.

3 Electricity Ten Year Statement (ETYS) (2024)

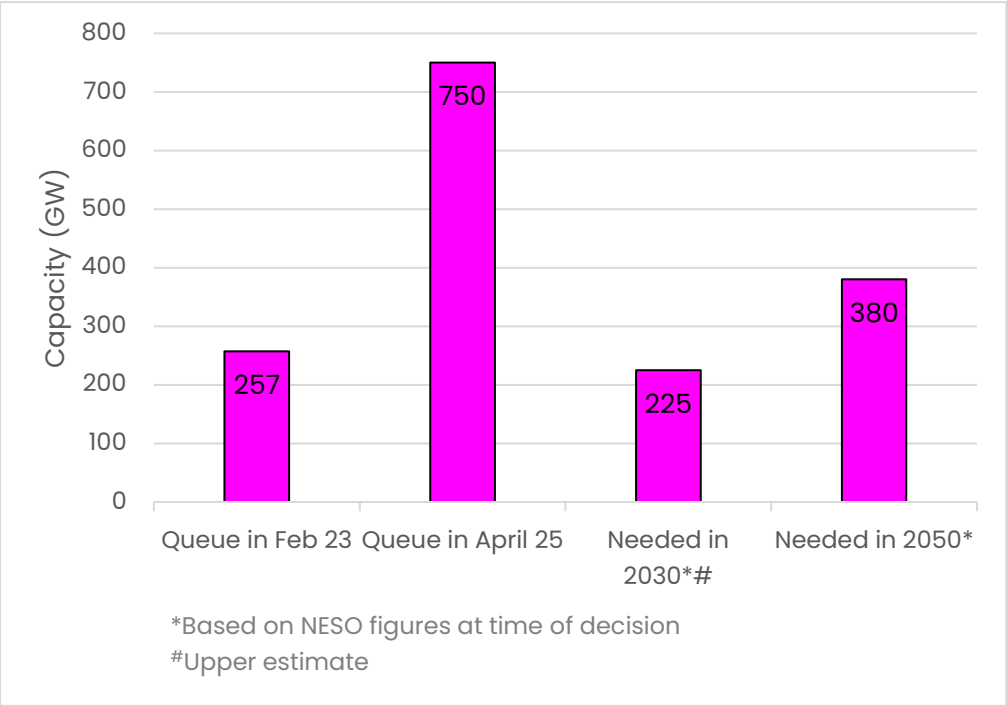


Figure 3.3: The 'first come, first served' approach. Source: NESO

Connections reform: Moving to a coordinated approach

The previous approach meant viable, strategically important projects were often delayed behind others that were less or even not viable. Projects that were at an early stage, less likely to proceed or not expected to be needed were blocking up the system.

We consulted extensively with industry about how best to reform the process for prioritising new connections. The result was a new connections framework, informed by government policy and regulated by Ofgem (Figure 3.4). It seeks to identify projects that are both ready to progress and needed to deliver a resilient, clean and affordable electricity system.

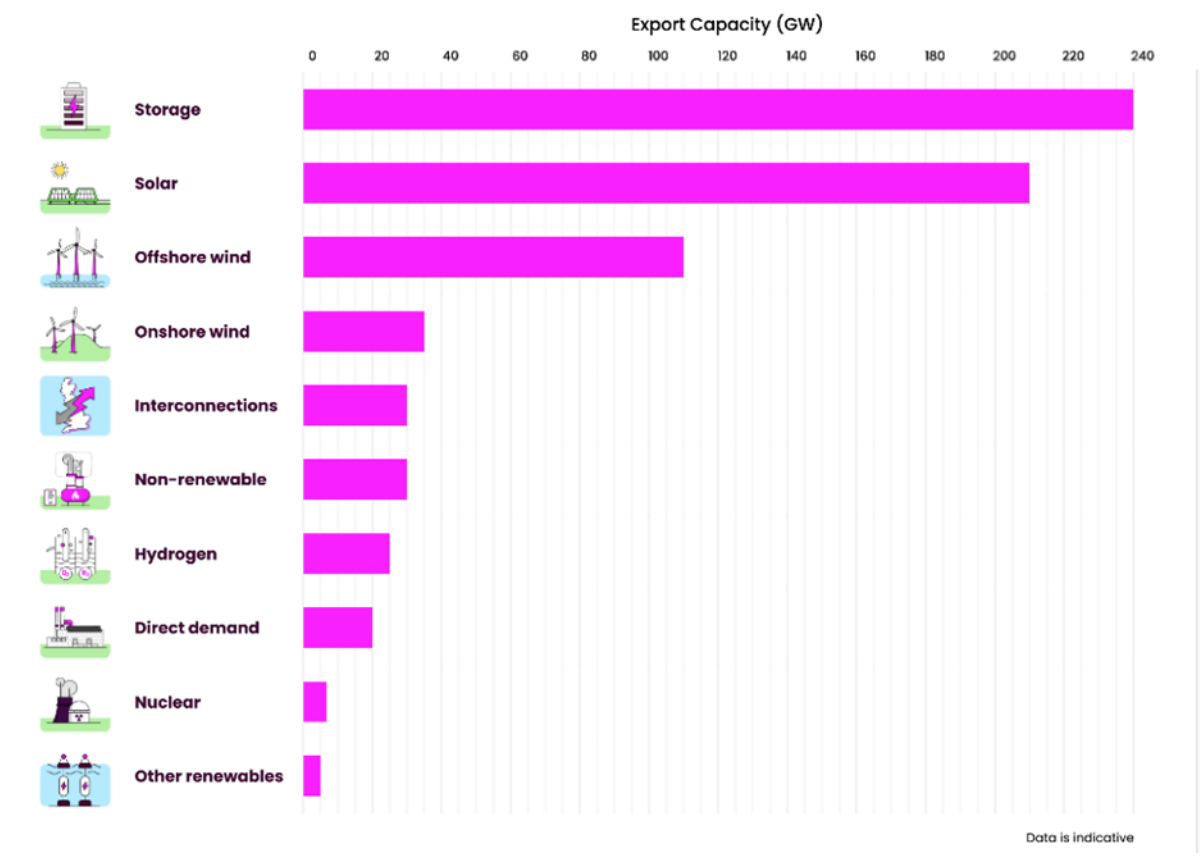


Figure 3.4: Why the connections process has been reformed and how roles are structured. Source: NESO

- Through the Clean Power 2030 (CP30) ambition, the UK Government has set the strategic direction for the energy system, defining the scale and type of infrastructure required to meet national goals.
- Ofgem has enabled and overseen the reforms through its regulatory framework, ensuring the changes deliver for consumers and are implemented fairly.
- Ofgem approved this new process in April 2025.
- The reformed process is being delivered through a joint programme between NESO, TOs and distribution network operators.
- NESO coordinates the overall approach, assessing which projects strategically align with government's Clean Power 2030 Action Plan and are ready to progress.
- NESO manages the pipeline and determines which projects move forward in line with the regulatory approval process.
- Network companies are responsible for designing, building and operating the physical connection infrastructure.
- They work with NESO on the connection offer and deliver the works required to connect projects to the system.

- Connections reform introduces a more coordinated and targeted approach so the right infrastructure is delivered at the right time.

The new delivery programme has streamlined connections reform, giving Great Britain what it needs (Figure 3.5). Projects that were unsuccessful in the last application window can reapply in a future application window, subject to meeting both readiness and strategic alignment criteria.

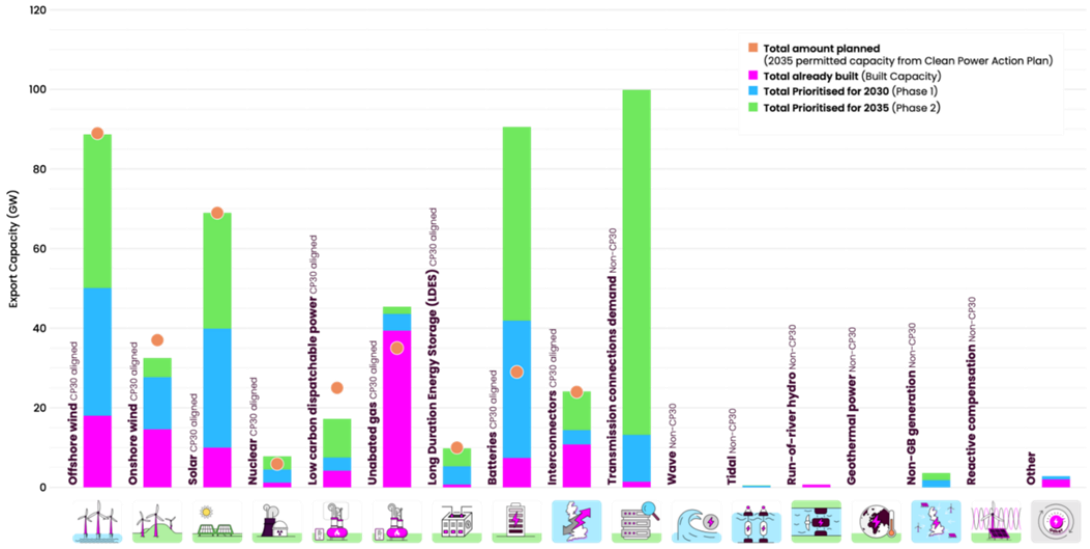


Figure 3.5: The new connections delivery pipeline. Source: NESO

- Connections reform alone is not a silver bullet.
- Transforming the grid connections process is a huge step towards unlocking further economic growth.
- But other measures are required for it to meet its full potential.
- To connect viable projects, more electricity network is needed.
- Around twice as much new transmission network (built by TOs) will be needed by 2030 than has been delivered in the past decade.
- Planning reforms are needed to ensure fast delivery, at scale.
- They must ensure communities are meaningfully engaged, and their views and expertise considered.

The demand challenge

Separate from the generation connections process, demand from large users (such as data centres) is still growing. That is why the UK Government and Ofgem needed to reform the demand connections process. They had to ensure the pipeline reflects viable, strategically important projects – rather than speculative applications.

NESO supports this work through its transmission connections and system planning roles. We provide independent analysis to help ensure the right projects move forward first. This helps to support a system that is resilient, clean and affordable for consumers.

Long-term changes in demand and generation create a need for investment

The identification of longer-term network needs is based on detailed modelling of how the transmission system is expected to operate under future conditions.

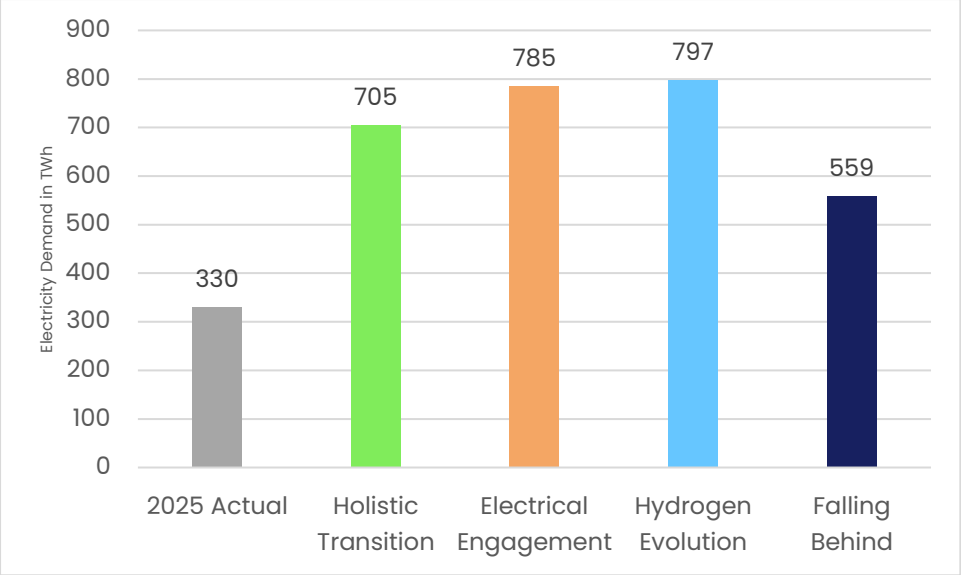
Planning for future system conditions

As the future is uncertain, we examine different potential pathways (called 'Future Energy Scenarios', or FES). Three of these pathways achieve the legal decarbonisation targets of 2050, while one pathway does not.[4]

Holistic Transition	Net zero is met through a mixture of electrification and hydrogen, with hydrogen mainly used around industrial clusters.
Electric Engagement	Net zero is met mainly through electrified demand.
Hydrogen Evolution	Net zero is met through fast progress for hydrogen in industry and heat.
Falling Behind	Considers a world where some decarbonisation progress is made against today, but at a pace not sufficient to meet net zero.

Under all FES pathways, electricity demand will be much higher in 2050 (Figure 3.6).

4 Future Energy Scenarios 2025: Pathways to Net Zero (November 2025)



Unavoidable increased demand

Even under NESO's most conservative 'Falling Behind' pathway, where Great Britain does not reach net zero, electricity demand increases by 70% in 2050 compared with today.

Figure 3.6: Electricity demand in 2050. Source: NESO FES 2025

Using the pathways, we develop a range of scenarios to define possible distributions of generation and demand across Great Britain. The pathways specify the total amount of generation and demand, its location, technology type and behaviour throughout the year. We then use this information to model how electricity would flow across the network. These studies do not predict a single future outcome but instead test how the network might perform across a range of plausible future system conditions.

Deciding what gets built where

The Strategic Spatial Energy Plan (SSEP) will provide a pathway for electricity and hydrogen generation and storage types.[5] Unlike FES, SSEP will set out a pathway to determine locations, capacities and timings of energy infrastructure needed in Great Britain. The plan will consider environmental, societal and spatial issues.

The first SSEP will cover the whole of Great Britain. It will map potential zonal locations, quantities and types of electricity and hydrogen generation and storage. This will help accelerate and optimise the transition to resilient, clean and affordable energy across Great Britain. The Secretary of State for Energy Security and Net Zero will decide the eventual pathway, with the final decision set to be published in 2027.

5 Strategic Spatial Energy Planning (SSEP) (2026)

Maintaining the network

Over time, wear and tear and environmental exposure degrade assets, and technological innovation can make them outdated. The bulk of the modern transmission grid was developed in the late 1950s and 1960s.

Many assets on the grid are more than 60 years old. The design life for transmission assets is usually about 40 years, although the average service life for transmission assets is longer, at 54 years.[6] This means there is an increasing need to replace the transmission assets that have been in service for more than 75 years.

Transmission owners (TOs) continuously monitor the health and performance of transmission infrastructure and equipment. They use a combination of remote sensors, inspections by maintenance crews and (increasingly) data collected by drones and satellites to do this.

If a potential problem is identified, there are three possible courses of action:

- Increase maintenance: No change to the asset, but an increase in maintenance and surveillance will prevent further deterioration and identify any further decline in asset condition.
- Refurbish the asset: This could include the replacement of small parts (for example the partial replacement of steelwork on a transmission tower) without replacing the entire asset.
- Replace the asset: An asset may be replaced if it is damaged, outdated or no longer functioning optimally – or it can be upgraded to align with new operational standards or planned network improvements.

From asset replacement to network reinforcement

In many instances, asset replacement is not like-for-like. When replacing an asset, TOs consider the future requirements that could impact the capacity of the new equipment. Where there is potential future growth in the area, TOs consider installing equipment of a higher capacity. This can prevent the need for further intervention on the network.

By coordinating work required on the network in this way, TOs can reduce the number of outages and the cost of maintaining and upgrading the network. It also reduces disruption for communities. This sort of forward-thinking investment can evolve into wider network upgrades, particularly where it aligns with identified system needs. When TOs identify opportunities for such investments, they are proposed and assessed alongside all network options – to ensure they are justified and deliver value for consumers.

6 Network Asset Management Strategy: A Risk-Based Approach to Asset Management (December 2024)

Making sense of what needs to be built

NESO is responsible for planning what Britain's transmission system will need in the years ahead. We do this by forecasting the capabilities the system must have to keep energy resilient, clean and affordable.

These requirements are called 'system needs'.[7] They detail what the electricity transmission system will need to deliver up to 20 years in the future.

We do this by dividing Great Britain's transmission system up into different zones (Figure 3.7). We then analyse how much electricity needs to be transported across the boundaries between each zone. We also look at how the network performs under different conditions, such as peak demand, high renewable output and fault scenarios. This analysis enables us to identify where and when the bottlenecks (or 'constraints') in the network will arise between the zones, where there is no capacity left for new connections or where the network may become unstable or challenging to operate.

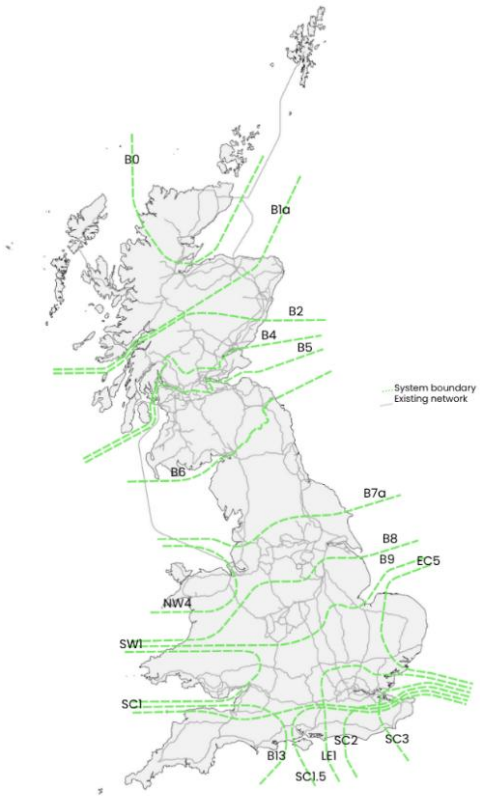


Figure 3.7: The boundary map of Great Britain's transmission system

7 Electricity Ten Year Statement (ETYS) (2024)

Network constraints

Network 'constraints' are bottlenecks that limit the amount of power the system can transport.

They occur when the transmission wires cannot transport enough power from areas of high generation to areas of high demand. This creates inefficiencies and pushes up system costs. Lower-cost generation that would normally meet demand has to be turned down and compensated. At the same time, more expensive generation closer to where electricity is needed is brought in to replace it. This can increase the cost of supplying the same level of electricity.

Figure 3.8 is a non-specific representation of a common occurrence on the network. It shows insufficient transmission capacity from the north to the south of Great Britain. To resolve this, cheaper wind energy in Scotland is paid to switch off and more expensive gas is switched on to replace it.

In the 'moderate wind' example in the figure, the supply and demand of electricity are equal, and there is just enough transmission capacity to transport the cheap wind energy to the demand centre. In the 'high wind' example, demand is higher and more wind generation is available. However, there is not enough transmission capacity to deliver all of the lower-cost wind power.

NESO instructs some wind generation to turn down to a level that the transmission system can manage and compensates the generators for lost output and revenue. Even after this, there is still a shortfall between generation (4 GW) and demand (6 GW). To balance the system, the control room instructs more expensive (often gas) generation on the other side of the constraint to come online.

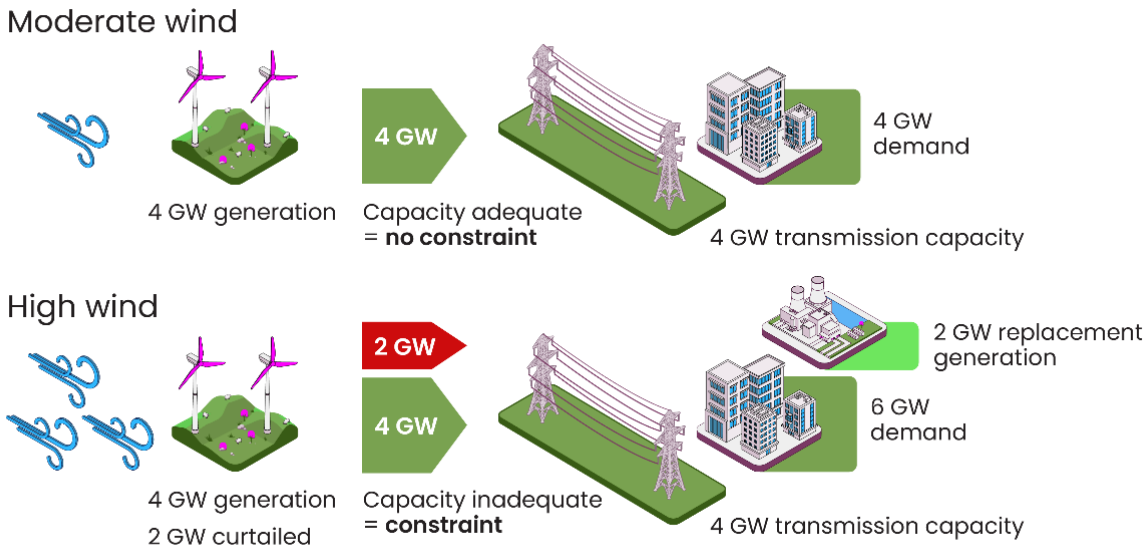


Figure 3.8: Examples of sufficient energy and constraints on the network

How we assess the different options

Our Future Energy Scenarios (FES) are used to provide a view of future demand and generation. We develop and use multiple scenarios to represent how generation and demand may evolve, ensuring that needs are not based on a single forecast.

Future demand and generation are entered into network models

We use detailed models of the transmission system to simulate how power flows across the network during different times of the year when the network is under greatest stress (such as peak winter demand). We include existing, ongoing (under construction) and planned network developments to ensure the analysis reflects the future system.

Models determine safety and reliability of cross-border transmission

We consider the technical standards governing the transmission system to test whether there are risks of assets being overloaded, or other risks to the reliability of the system. TOs provide the underlying network data and help us interpret the asset's capabilities and operational limits. These limits may result from circuits getting too hot or becoming unstable, or because safety margins have been exceeded.

Model outputs help us identify future network requirements

By identifying a system need, we can find the solution to address it. Rather than selecting a specific technology at this stage, we translate the identified issue into a set of functional requirements. These describe the performance that the network must deliver, ensuring that different types of solutions can be compared on a consistent basis, for example:

- the amount of additional transfer capability required between areas
- the need to maintain voltage, frequency and system stability within acceptable limits
- the ability to meet security standards under fault scenarios

Think of it like road planning

Instead of designing a road for today's traffic only, traffic planners consider how traffic might grow or change in the future – at rush hour, during public events or as new areas develop.

Electricity network planning works in a similar way. It tests how the system performs under different future conditions before deciding what upgrades are needed.

TOs support this by providing technical and operational insight. This helps to define realistic, achievable requirements that are consistent with how the network operates in practice.

A more active role

From 2028, we will have a more active role in the high-level design choices for new infrastructure. This will help to strike a balance between consumer costs, timely delivery, and community and environmental disruption from an early stage of network planning.[8,9]

It will involve defining high-level design choices for TOs to consider when addressing future network requirements. These may include:

- the broad geographical area in which a reinforcement could be required and where a connection or reinforcement will connect between
- whether the need should be met using upgrades to the existing network or new network, and its minimum capability, capacity and voltage
- whether the route should be predominantly onshore or offshore, or overhead or underground
- whether high-voltage alternating current (HVAC) or high-voltage direct current (HVDC) technology should be used

Survey finding

Respondents told us their top four most important factors to consider about new infrastructure are safety (68%), local environment and wildlife (59%), visual Impact (50%) and disruption during construction (50%).

Alternatives to upgrading the network

Before upgrading the network, it is important to understand whether the underlying problem of getting electricity from where it is generated to where it is needed can be solved in other ways.

Three options stand out: storage, co-location and flexibility. Stored electricity can cross constrained boundaries at a different time. Locating new demand near new generation means the electricity does not need to travel as far. Making demand more flexible supports the network being used more evenly. None of these fully replaces the need for new infrastructure, but each can reduce how much is required.

Storage

Electricity storage in Great Britain is mostly delivered by grid-scale batteries, but there are also four pumped-storage hydro facilities. These pump water uphill during low electricity

8 National Policy Statement for Electricity Networks Infrastructure (EN-5) (December 2025)

9 Centralised Strategic Network Plan: Methodology (April 2026)

demand to store energy, which can then be released downhill through turbines to generate rapid-response power during peak demand. Storing energy on both sides of a constraint can help reduce its impact by soaking up cheap power when there is excess generation or low demand. This can then be released later when it is needed. We have also run a series of Pathfinder projects that procure services from storage and other flexible assets to help manage specific constraints.[10] These projects are working with Ofgem and the wider industry on market arrangements that would enable more accurate payment for storage based on the network value it provides.[11]

Co-locating demand and generation

A second approach is to encourage large new electricity users to locate near major sources of generation rather than far from them. These large users include data centres, hydrogen electrolysers and industrial sites. Building a data centre next to a Scottish wind farm means its electricity does not travel hundreds of miles through a constrained network. Britain's single national wholesale price presents a challenge, however. Currently, a business pays roughly the same for electricity wherever it sets up. This means there is little financial reason to choose a windy, generation-rich area over one closer to existing demand. The Department for Energy Security and Net Zero (DESNZ) carried out a detailed review of alternatives, including locational or zonal pricing. This considered how prices would vary across different parts of the country to reflect network constraints. Following this, DESNZ decided to retain and reform the existing national pricing approach. Further reviews are now examining how the connections process and targeted locational charges can be used to influence where demand is located.[12] We have carried out and published analysis to inform the ongoing DESNZ review of how prices should be set.[13] We are also developing the Strategic Spatial Energy Plan, which aims to give clearer signals about where new generation and demand should ideally connect.

10 Constraints Collaboration Project (2026)

11 Ofgem: Super battery projects that maximise renewable-generated power enter next phase of Ofgem's green power storage scheme (September 2025)

12 DESNZ: Reformed National Pricing (2026)

13 NESO: Reformed National Pricing (2026)

Flexibility

'Flexibility' means shifting when electricity is used rather than how much. Examples include charging an electric car when wind output is high or pausing an energy-intensive process during peak demand. These actions help reduce strain on the network at critical times. We account for expected flexibility in our long-term planning assumptions, though estimating how much consumers and businesses will actually be able to offer is difficult.

We also operate the Demand Flexibility Service, which pays households and businesses to reduce consumption at certain times. At the same time, we are reforming the balancing and ancillary service markets so that smaller, distributed flexibility providers can participate more easily and more fairly alongside large power stations.

You can help to balance the grid

Our Demand Flexibility Service rewards households and businesses for shifting when they use electricity: using the dishwasher, EV charge or tumble dryer out of the busy late-afternoon peak or sometimes using *more* electricity when there is a surplus of cheap wind power.

When you take part, you are standing in for a gas power station that we would otherwise have had to switch on, or helping us absorb surplus power. In return, bill payers can earn cash rewards from their supplier.

The United Kingdom was the first country in the world to launch a service like this, and nearly 2.5 million homes and businesses have already joined it.

4. How new network solutions are chosen



Transmission owners lead the development of different options to meet network requirements

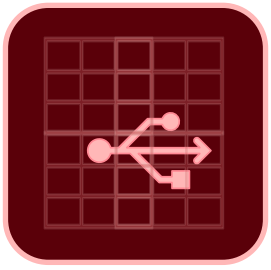
Where new or upgraded infrastructure is needed, transmission owners (TOs) lead the development of potential options to meet that requirement. Option development is not a one-off activity. Instead, TOs and NESO refine and reassess options before any commitment to build.

During this iterative process, TOs:



Update assumptions and underlying data

The latest data feeds back into the design process each year, so the understanding of the engineering problem, solution requirements and design constraints become more accurate over time.



Improve technical designs

Engineering details and configurations are refined, routes adjusted, equipment specified and site layouts optimised as the design matures.



Screen out weaker options

Options that are clearly less effective or likely to score very poorly against our assessment criteria are dropped, narrowing the field to the most promising options.

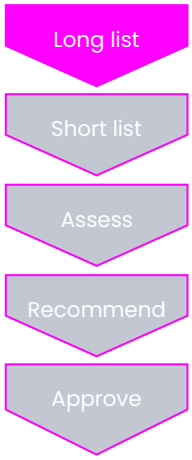


Combine or modify options

Where it makes sense, options are merged or reshaped to create stronger solutions from the long list of existing candidates.

This iterative process can be broken down into five stages.

A long list of options that aim to meet our requirements is identified and screened.

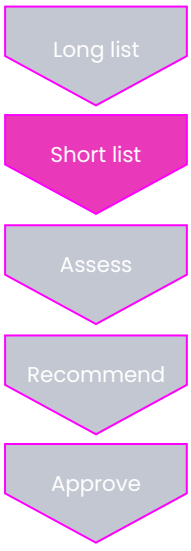


Potential solutions may include:

- upgrading existing assets to increase their capacity
- installing new equipment in substations to facilitate this increased capacity
- commercial solutions proposed by NESO where the behaviour of participants on the network can be adjusted to unlock more capacity
- building new infrastructure, such as transmission lines, subsea cables or substations

Each longlisted option undergoes a high-level evaluation to check whether it is technically feasible, what the indicative cost might be, whether it has the potential to have significant environmental and community impacts or difficulty obtaining planning permission, and how quickly it might be delivered. At the end of this process, the remaining options are shortlisted and then taken forward for further development.

Short-listed options go through a more detailed design process.



The TOs then undertake more detailed modelling of the shortlisted options to understand how the power flows on the network would change due to the potential solutions. They also assess how well these options might perform against our assessment criteria and the standards which ensure the reliability of the transmission system. This modelling is submitted to us for verification and validation.

At this stage, the TOs also produce high-level conceptual engineering designs and, in the case of new transmission routes, specify the start and end point of the option. The area examined for the potential route varies in width based on the maturity of the option. It represents the general area through which the transmission line could be built. The corridor can be further refined based on the limitations of the chosen technology (for example avoiding sharp corners), the need to connect to existing infrastructure and the need to avoid built-up and environmentally sensitive areas as far as possible.

Why are options refined over time?

Early options are often high-level and based on initial assumptions. As more detailed information becomes available (for example better cost estimates, engineering studies and system analysis), these options are updated and improved.

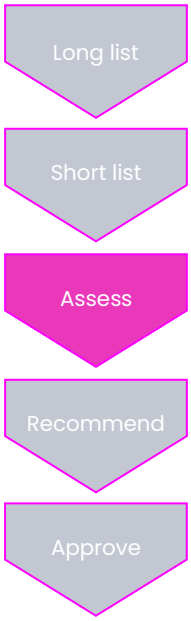
This iterative process helps ensure that decisions are based on the best available evidence and that the final options are technically feasible and deliverable.

TOs produce a cost estimation for each option over the whole life of the asset, including construction, operation and decommissioning. Another key consideration is how long it could take to deliver the new infrastructure. This is particularly important, as this has a significant impact on whether the option meets the network requirements within the planned timeframe.

The developed short-list options are taken forward to the next step, where we carry out an 'options assessment process' to compare the costs, benefits and impacts of each option.

We assess the options based on defined criteria and make recommendations

The options assessment process is iterative and conducted alongside the options development process.



We assess each option against a set of key criteria.

These criteria reflect both the needs of the electricity system and the wider impacts of network development. The key criteria are economic, environment and community impact, deliverability and operability.

The economic assessment uses cost–benefit analysis (CBA). We assess the overall cost and value of each option over its lifetime, including up-front investment, ongoing operational costs and the extent to which the option reduces the operational costs of the transmission system. Some options may have higher initial costs but deliver greater long-term benefits, so we focus on overall value rather than lowest cost. We conduct the economic assessment first to filter out any options that do not provide good value for money.

Economics

We use our pan-European market modelling tool to carry out our CBA process using the supply-and-demand mix of different long-term planning scenarios. We consider a wide range of commercial and network options made up of assets that could be either onshore or offshore. For network options, we also assume the appropriate asset life for each reinforcement (typically 40–50 years). There are several topics that we can attribute a monetary

Can modelling exactly predict the future?

No. These studies explore how the network might perform under a range of possible futures.

Consistent patterns include recurring constraints or stability issues. By identifying these, network planners can focus on needs that are likely to arise, even though the exact future system cannot be predicted.

value to (based on the Government's Green Book).[14] These can be societal costs, long-term carbon costs, operating costs and delivery estimation costs (when the asset switches on) – all of which are considered as we narrow the network options to find the best value for the consumer over the long term. For commercial options, we compare the cost to mitigate a local network constraint with the cost of building a new asset. Building new assets can take years, and so the benefits of doing this are considered alongside cost implications and feasibility.

Environment

Each option has environmental factors that we will need to consider. Whether it is a new overhead line (OHL) across the landscape, a substation extension, a new substation, a converter station or undergrounding, it has an environmental impact. The designer would have considered these environmental factors and, where possible, would look to reduce the impact on the environment and habitats. They would also seek further environmental protection by, for example, avoiding sensitive environments and historic sites.

Community

Similar to environmental impact, each option has community impact factors that we will need to consider alongside our public sector equality duty. This could be to bypass or underground through an area of historic importance.

Wider system considerations

A solution that fixes a problem in one area can create new issues elsewhere. By considering how options interact across the whole network, planners ensure that solutions improve overall system performance, not just a single part of it.

NESO and TOs assess how each option performs within the wider transmission system, rather than considering it in isolation.

In particular, we consider:

- how the option affects power flows across the network
- whether it reduces existing constraints or shifts them to other areas
- how it interacts with other planned or potential network reinforcements

Deliverability

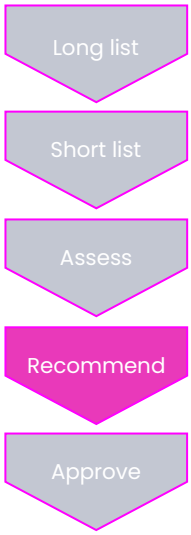
Deliverability is based on NESO's and TOs' experience of delivering network options. This includes installation complexity, and the time needed for design, development and construction. The designer provides an estimate year of when the option could go live. They consider procurement of the assets, organising works personnel, how complex it is and keeping the transmission system secure so that the lights stay on. There are often complications in the design process (for example challenging terrain, offshore wrecks) that might require updating the design, cost and programme projections.

14 The Green Book (February 2026)

Operability

We are obligated to ensure the transmission system is resilient, clean and affordable for all foreseen circumstances. When we want to connect, for example, substations, OHLs or new technologies, we have to confirm that they will not disrupt customer supplies. And 'customers' can be anybody, from large power station generators to domestic consumers. We conduct extensive studies, testing each option under different fault scenarios. An option can only be recommended when it complies with the Security and Quality of Supply Standard (SQSS).[15]

NESO make recommendations on which options best meet the requirements based on the assessment criteria.



When determining the combination of options that provides the best performance across all assessment criteria, economic value may sometimes be the deciding factor. At other times, factors such as deliverability, environmental impact or system performance may play a more significant role.

Different options will perform differently across the assessment criteria. For example, one option may have a lower cost but greater environmental impact. Another may be more expensive but deliver stronger system performance or be easier to construct. We explicitly consider these balances and recognise that no single option is likely to be best in all respects. We also consider the local benefit an option could bring to an area and how the recommendations collectively enable the efficient development of the system.

Why isn't there always a clear 'best' option?

Different options can perform better in different ways. For example, one may be better economically, while another may have a lower environmental impact or be quicker to deliver. Choosing between options involves considering these balances and making a judgement about what delivers the best overall outcome.

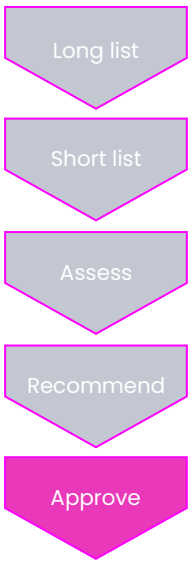
We do not assess all options in the same detail from the outset. Instead, we screen options early, removing those that are clearly less effective or not feasible. We work with TOs and other stakeholders to refine the better options and technical design, and check important assumptions.

15 Security and Quality of Supply Standard (2026)

Ofgem decides whether TO-proposed projects receive funding approval

Before making a submission to Ofgem, TOs develop the design in greater detail, refine cost estimates and delivery plans, and carry out more detailed environmental and planning assessments.

Ofgem regulatory approval is a key step to secure funding for the project.



Projects commonly receive funding in progressive phases, with larger initiatives generally starting with limited financial resources to enable development of their plans. On demonstrating satisfactory progress, additional funding may be allocated to advance through subsequent planning and approval stages. Smaller projects typically use established funding pathways. Full funding is provided once a project is confirmed as necessary and prepared for implementation. Ofgem assesses whether the proposed solution addresses a system need, represents value for money and is supported by technical and economic evidence. Ofgem may challenge assumptions, request further justification or require refinements before approving funding. This independent review provides an important check that ensures decisions are robust, transparent and in the interests of consumers.

Our recommendations inform the proposals that TOs make for regulatory approval and help Ofgem reach a decision.

Who decides what gets built?

NESO ensures supply meets demand, while strategically planning and coordinating the design of future electricity networks.

Ofgem decides whether and when investment is funded.

TOs develop detailed designs and deliver projects, including securing planning consent.

Planning authorities determine consent decisions.

The Centralised Strategic Network Plan

We are moving to a more holistic approach through the Centralised Strategic Network Plan (CSNP).[16] This approach is designed to improve how options are assessed to improve deliverability and to make the process more transparent for the public.

In future, NESO will assess a wider range of options when a need for network investment is identified. This will give greater visibility of the alternatives considered and a clearer explanation of why certain options perform better than others. For the first time, we will also be able to develop and test our own options. This will allow us to compare them directly with proposals submitted by TOs and identify solutions that best support a resilient, clean and affordable energy system.

We will also carry out a Strategic Environmental Assessment, along with a Habitats Regulation Assessment and Marine Conservation Zone Assessment at an earlier stage.[17] This means environmental impacts can be considered in more detail before TOs move into detailed design, supporting better outcomes for communities and the environment.

16 Centralised Strategic Network Plan: Methodology (April 2026)

17 Strategic Energy Planning Environmental Assessments (2026)

Public

5. Key design considerations, costs and balances



Linear assets

Electricity can only power our homes, offices and industries if it has a complete, uninterrupted circuit. That circuit allows the electricity to flow from generators to where it is needed — kettles, computers, phone chargers, electric vehicles, data centres and hospitals — and then back again.

This principle applies to all types of generation. It does not matter whether the electricity comes from gas, offshore wind or sunlight captured by solar panels. We have a highly interconnected transmission network where power flows from generation to demand across multiple parallel paths. When there is no continuous path, electricity cannot flow and energy cannot be delivered.

Across most of the world, these circuits are made using copper or aluminium wires. These metals are used because they conduct electricity very efficiently, helping power flow reliably from where it is generated to where it is needed.

Despite the use of low-resistance conductors, electrical energy still experiences some losses as it flows from generator to customer, heating the wires in the process. The higher the flows of electrical current, the hotter the wires become. Using larger wires would reduce the resistance and thereby lower the temperature of the wire, but wires thick enough to carry the amount of electricity we demand would be impractical to make and use. Thankfully, however, it is possible to reduce the electrical current and still transmit the energy we need. This is done by raising (known as 'stepping up') the voltage at which it is transmitted over long distances, and lowering (or 'stepping down') the voltage again locally before it is distributed to our homes and workplaces. Running these circuits at a higher voltage therefore means they can carry more power.

For high-voltage alternating current (HVAC) transmission, the highest voltage in Great Britain is 400 kilovolts (kV), although parts of the network run at 275 kV and, in Scotland, 132 kV. For high-voltage direct current (HVDC) transmission, the highest voltage in Great Britain is 600 kV.

AC and DC flows: Electricity can be transmitted either as alternating current (AC) – where the current flows backwards then forwards, repeating this 50 times a second – or as direct current (DC) – where the current flows in the same direction all the time. DC does have advantages for a few, very specific, electricity transmission applications, which we discuss below. However, AC is particularly appropriate for transmitting electricity across the country's highly meshed transmission network. This is because the supply voltage can be changed anywhere along a circuit route by inserting a transformer. The DC equivalent to an AC transformer would require a much larger installation of complex power electronics, which would not be cost effective.

Comparison of route asset technologies

A transmission owner (TO) must choose how to fulfil the requirements of a transmission customer. The customer could be a new generator, a new demand centre or an energy storage supplier. These choices are made for technical and cost reasons, and to mitigate the impact on communities and the environment. The following sections explain the technical choices available to the designer, and the likely impacts of each choice.

Onshore (HVAC overhead lines) and offshore (HVDC subsea cables)

Great Britain benefits from some of the world's best onshore and offshore wind energy resources, especially in Scotland and the North Sea.[18] However, electricity demand tends to be concentrated in the south of the country. This means much of the renewable power generated must be transported over long distances to reach its greatest points of demand.

To deliver this power, the options include routeing it onshore, mostly with overhead lines (OHLs), or offshore, using undersea cables. But because onshore and offshore transmission options have their own distinct electrical and physical characteristics, they cannot be easily compared. For this reason, system planners must navigate a complex set of factors when choosing which approach to take. Table 5.1 compares the two options.

Survey finding
Respondents told us the most important issues for deciding between OHL and UGC were environmental impact (48%), safety (47%) and reliability (48%).

Table 5.1: Onshore or offshore?

	Onshore	**Offshore**
How do they transmit power?	Via high-voltage alternating current (HVAC) overhead lines (OHLs)	Via high-voltage direct current (HVDC) subsea cables
How visible are they?	Pylons, conductors (wires) and substations are visible across the countryside, especially up close	Subsea cables are hidden from view Require onshore converter stations and substations, which are visible, especially up close
Do they take up much land?	Each pylon has a small physical footprint Land between pylons below OHLs is largely usable (with height restrictions)	Converter stations can take up 8–18 hectares (depending on capacity)

18 wwindea.org

		Subsea cables may affect commercial fishing near the cable (especially bottom trawling)
Are planning and consenting complex?	Often complex, owing to onshore route restrictions	Similarly complex, owing to offshore route restrictions
Which is quicker to construct and deliver?	Quicker construction Careful route selection and planning consent for long-distance routes can extend overall delivery timelines	Slower and more complex to construct, often require favourable weather conditions.
Are they easy to maintain and repair?	Require only periodic inspection and maintenance Exposed to weather damage like ice, lightning and storms Easily accessible by ground, drones or helicopters Repairs typically take hours to days	Require less cable maintenance once installed Converter stations require regular maintenance Occasional reburial of cable may be needed Exposed to accidental damage (for example ships' anchors and fishing gear) or potential malicious damage Require specialist vessels and remotely operated vehicles (ROVs) to locate and repair faults Although faults can be rare, outages can last for many months
Can they be expanded?	Higher capacity can be introduced through larger or specialist conductors that can operate at higher temperatures Easier to extend and make new connections using standardised components	Each cable system limited to approximately 2 GW Multiple cables and converter pairs needed for equivalent capacity to OHLs Can be extended to form multi-terminal links if designed with sufficient space and the technology allows for it
What are the environmental considerations?	Have a range of potential impacts on landscape, communities and habitats	Seabed disturbance and impact on sensitive marine environments during construction

	Risk of bird collision, particularly in sensitive locations for bird populations Potential for flexibility and micro-siting when considering tower placement, access tracks and temporary haul roads Less carbon-intensive construction	Fewer environmental impacts during operation Additional impact of onshore converter station More carbon-intensive construction
Cost	Variable Depends on application Typical lifetime cost of £3.72m–£9.2m per kilometre	Variable Depends on application Typical lifetime cost £7.7m–£18.8m per kilometre

Overhead lines and underground cables

In the majority of onshore situations, OHLs are the most cost-effective way to transport electricity in bulk over long distances. They are relatively straightforward to build, operate and maintain. However, because they are visible, their routes and designs are carefully chosen to reduce impacts on the environment and local communities.

UGCs can provide an alternative transmission solution when OHLs are unsuitable, for example in designated landscapes or physically constrained locations. However, they are more complex to install and typically cost more than the overhead alternative. OHLs produce electric and magnetic fields (EMFs), and UGCs produce magnetic fields. In both cases, the allowable field strengths are tightly regulated and kept within established and conservative safety limits.

These considerations – efficiency, cost, environmental impact and safety – underpin how decisions are made between OHLs and UGCs.

Table 5.2 compares the two options, and Figure 5.1 demonstrates the physical differences.

Survey finding
41% of respondents had a positive view of OHLs, with a notable proportion holding a negative view (21%). In contrast, three quarters (75%) were positive about UGCs. However, after learning more about the different technologies, when asked if their view had changed, over half (53%) felt more positive about OHLs, while 40% felt more positive about UGCs.

Table 5.2: Overhead or underground?

	Overhead lines	**Underground cables**
How big are they?	Pylons are approximately 46 m high (about half the height of Big Ben) Typically, up to four pylons per kilometre Carry multiple, visible conductors (wires)	Buried cables are between 10 cm and 15 cm in diameter Temporary construction corridor Minimal long-term visual impact (While largely invisible once installed, UGCs still require some overground infrastructure. This can include large voltage control equipment and cable sealing ends where the cable connects to substations, and small earthing kiosks placed above ground along the route of the cable)
Land use	Small footprint at each pylon leg Land between pylons largely usable (with height restrictions)	Wide continuous working corridor temporarily dug Usable after land reinstatement (excavation restrictions apply)
Planning and visual impact	Strong policy preference in general Visible in landscape despite mitigation	Used more frequently in designated landscapes or densely populated urban areas High short-term visual impact that reduces over time
Construction and delivery	Localised works at pylon sites Overhead stringing of conductors	Extensive trenching and haul road Significant temporary land disturbance
Maintenance and repairs	Low routine maintenance Periodic inspection and repainting	Low routine maintenance Joint inspection and testing required
Future expansion	Relatively straightforward Involves uprating conductors and minor tower upgrades	Limited Upgrades difficult Typically requires new cable installation

Environmental considerations	Have a range of potential impacts on landscape, communities and habitats Bird collisions are the greatest environmental risk, and so TOs work hard to avoid sensitive bird habitats and use flight diverters to reduce this risk further Potential for flexibility and micro-siting when considering tower placement, access tracks and temporary haul roads	Reduced landscape and visual effects during operation Increased ground-based impact during construction Less opportunity for micro-siting once a route has been selected Construction can impact ground-based habitats and species, hedgerows and buried archaeology Construction effects can be reduced by mitigation and reinstatement
Cost	Variable Depends on application Typical lifetime cost of £3.72m-£9.2m per kilometre	Variable Depends on application Typical lifetime cost of £13.97m–£39.32m per kilometre

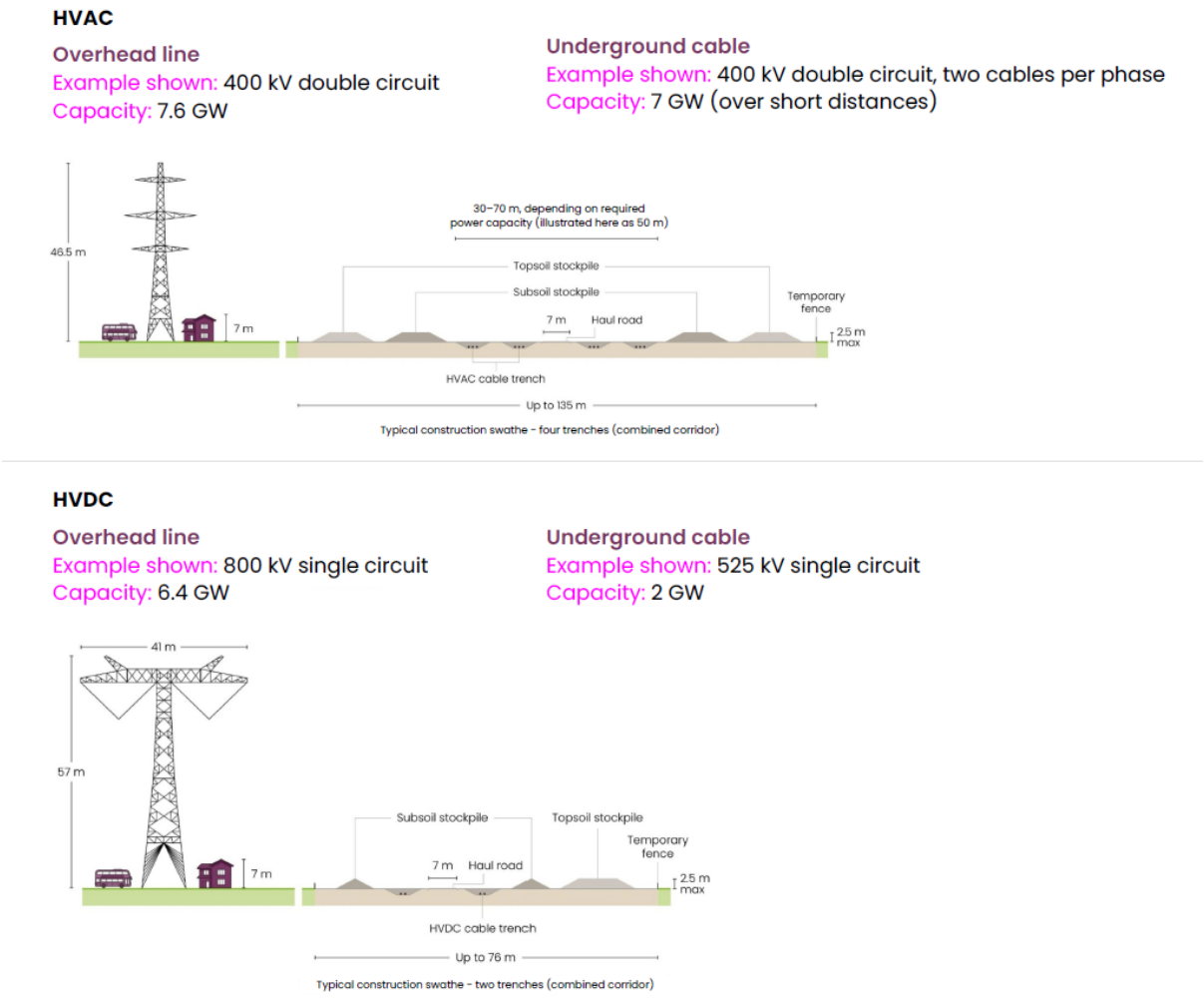


Figure 5.1: Comparison of HVAC and HVDC transmission technology. Please note that we do not currently operate overhead line HVDC on the GB transmission network. Source: NESO

Overhead lines

The overhead transmission line is the principal technology used to build electricity transmission networks around the world. There are overwhelmingly good reasons for this, although there are some downsides, too.

The infrastructure

An overhead transmission line is a set of high-voltage conductors safely insulated from the ground by air. These conductors only require mechanical support at intervals along the line's length by insulators attached to support structures.

In the UK, an OHL generally comprises:

- painted steel lattice support towers (pylons) with three lattice arms on each side, and a peak – though there are alternative designs and materials
- insulators (strings of porcelain or glass disks, or polymer materials) that hang from the ends of the pylon arms to support the conductors

- high-voltage conductors, normally arranged in bundles of two, three or four wires, depending on how much electrical power is to be carried
- a single earth wire (a low- or zero-voltage conductor) supported at the tower peaks to conduct away lightning strikes
- concrete foundations for each tower leg, to ensure structural stability
- conductor fittings – spacers and Stockbridge dampers (which reduce conductor clashes and vibration in strong winds)

On flat, open terrain, OHLs normally have around three to four spans per kilometre. For these conditions, the pylons will be spaced at about 300–350 m intervals along the route.

The heights of OHL towers are governed by the need to provide a safe clearance between the lowest conductors in the middle of the span and anything or anybody on the ground below them. For this reason, where an OHL passes over high ground, the pylons there may exceed the average height, whereas when the OHL passes through a valley the pylons may be shorter than the average height.

An OHL is normally the cheapest way to safely transmit high-voltage electricity in bulk, over long distances. Some smaller or more remote generators can connect to local distribution substations, such as solar, battery and hydroelectric generators. Indeed, for some rocky or mountainous terrains, such as in Scotland or North Wales, OHLs are the only way to transmit electricity.

Do we really need six sets of wires in the sky?

OHL pylons have six arms to support two separate, 3-phase circuits.

The 3-phase supply

- It is true that one electrical circuit only needs one 'go' and one 'return' connection.
- Indeed, the earliest generators used a single copper wire winding with one end being the 'go' and the other end the 'return'.
- Designers later discovered they could have all the benefits of three generators by squeezing three windings into a single machine.

It turns out that, through careful design, the three generators provide their full outputs while sharing just three connections. This 50% saving in conductor costs has been adopted around the world for AC systems. It is known as the '3-phase supply'. This is why AC pylons have multiples of three arms.

Two separate circuits

Three arms on one side of a pylon support one 3-phase circuit. The three arms on the other side of the pylon support another, completely independent 3-phase circuit. Benefits of this 'double circuit' approach include:

- Greater capacity: Transmission capacity and efficiency are improved along a route by including a second circuit in the initial design.
- Lower energy losses: By having more than one route for the electricity to flow, electric currents in any circuit are lower, so conductor heating is reduced.
- Operator flexibility: Taking one circuit out of service for maintenance does not impact customer supplies, since the other circuit still operates.
- Improvements to supply reliability: If one circuit has a fault, the other circuit can immediately pick up the load.

Overhead line impacts

Construction of overhead lines

Pylons require foundations. Once completed, steelwork is delivered and assembled, mainly on site, and with a crane. A temporary roadway protects surrounding fields from compaction caused by the heavy vehicles used during the pylon's construction (Figure 5.2). Once all the pylons are in place, the wires are pulled into place for each straight section of the OHL (Figure 5.3).



Figure 5.2: Temporary stone access track to pylon construction area. Source: National Grid



Figure 5.3: Pylon under construction. Source: National Grid

Impact of overhead lines

Steel lattice transmission towers (pylons) are the starting presumption for new OHL routes. The relatively open silhouette of lattice towers make them easier to see through. This means the landscape behind them, especially wooded or moorland areas, can be seen more easily, reducing the OHL route's visibility. When developing route options for new OHLs, developers can encounter areas of particular sensitivity. These may include

settlement areas, designated landscapes, protected habitats and Heritage Coasts (specific areas whose undeveloped character must be protected by local authorities). UK planning policies assign varying levels of 'protection of amenity'[19] to these areas. Those developing new lines should endeavour to avoid or minimise the impacts on the amenity value of sensitive areas. It is important to balance the benefits of following the hierarchy of designated protections in national planning policies against the technical feasibility and the costs of routeing an overhead line to avoid areas of amenity value. As such, there are ways for developers of transmission infrastructure to lessen the visual impact of OHLs:

Alternative tower designs

These include monopole and shorter steel lattice towers. They can reduce landscape disruption and lessen the OHL's visual impact in certain highly situation-dependent settings. However, they are often more difficult to construct and maintain. Additionally, their increased costs must be weighed against their effectiveness.

Landscape-led approach

The routeing of an OHL should follow a landscape-led approach. This means considering competing factors to minimise the line's overall impact on communities and the environment while delivering the technical need. For example, the OHL could avoid prominent skylines or ridgelines (Figure 5.4). It could use trees or hills to reduce its visibility or perceived height. However, routeing the OHL through lower-lying areas may bring infrastructure closer to settlements and properties, and so the developer has to balance competing considerations along the route.

Undergrounding

Where a proposed transmission route must pass through a designated landscape and re-routing is not feasible, underground cables (UGCs) can be considered as an alternative to OHLs. Before using this underground solution, the TO will carefully assess the advantages and disadvantages of using a UGC. The assessment of potential underground solutions must carefully balance the advantages and disadvantages of undergrounding. These include environmental impact, costs and associated technical issues within the context of relevant obligations.

19 'Protection of amenity' means safeguarding the living conditions, health and general wellbeing of neighbouring residents and the surrounding community from the negative impacts of a new development or change of use.



Figure 5.4: An OHL route taking lower ground to minimise 'skylining'

Overhead line operations and maintenance

OHLs enable flexible grid operation and can accommodate significant short-term overloads under emergency conditions. However, they are more susceptible to lightning strikes than UGCs. In such events, automatic switching systems at substations rapidly isolate and restore the circuit, typically returning lines to service within seconds without lasting damage.

Specialist maintenance teams use helicopters and drones to inspect OHL infrastructure and identify maintenance requirements. Where intervention is needed, engineers access the assets by climbing towers or using specialised equipment. Vegetation management is also carried out using forestry machinery to prevent encroachment on conductors and structures, ensuring safe and reliable operation.

Overhead line costs

As with all electrical transmission equipment, separate cost estimates can be made for the capital build costs and the lifetime operating costs – that is, the costs of heating losses in the conductors over their operating life. There are two key variables when assessing these costs:

- the design rating of the equipment (its maximum power-carrying capacity)
- the anticipated loading of the equipment (the amount of electricity it is expected to carry most days)

Table 5.3 compares the average lifetime costs for a typical 400 kV OHL in Great Britain (based on an independent report published in 2025).[20]

Table 5.3: Typical lifetime costs* of a 400 kV OHL of low, medium and high rating.

Route length	Low rating (≈2,500 MW)	Medium rating (≈5,000 MW)	High rating (≈7,500 MW)

20 'A comparison of electricity transmission technologies: Costs and characteristics' (2025)

3 km	£3.72m/km	£5.97m/km	£9.20m/km
15 km	£3.18m/km	£5.35m/km	£8.31m/km
75 km	£3.02m/km	£5.05m/km	£8.03m/km

*Costs based on 2023 prices.

The estimated construction capital and lifetime operating costs in Table 5.3 vary between 69% capital and 31% operating costs for the short route, low-rating OHLs to 37% capital and 63% operating costs for the long route, high-rating alternative.

In practice, unit cost estimates vary widely, depending on many external factors associated with specific projects. However, the figures given in the table represent a central, or 'expected', estimate in each case.

Underground cables

Where the use of OHLs is technically impossible or inappropriate, high-voltage UGCs are a viable alternative. For example, UGCs can offer a good solution to the challenge of finding urban transmission routes (often installed in tunnels). They can provide a technically feasible solution when a new OHL is deemed unacceptable, for example within a designated landscape. Three documents provide further guidance on when it is appropriate to use UGCs. They are:

- for England and Wales, the UK Government's National Policy Statement for electricity networks infrastructure (EN-5)
- for Scotland, the Scottish Government's National Planning Framework 4 (NPF4)
- NESO's Electricity Transmission Design Principles (ETDP)

The infrastructure

OHL conductors are insulated from the ground by a large air separation. UGC conductors, on the other hand, are separately covered with a thick layer of very pure, flexible plastic – normally cross-linked polyethylene (XLPE). This provides the insulation between the high-voltage conductor and the ground. Further metallic, plastic and sometimes steel wire layers are then wrapped around the outside of the XLPE layer (Figure 5.5).

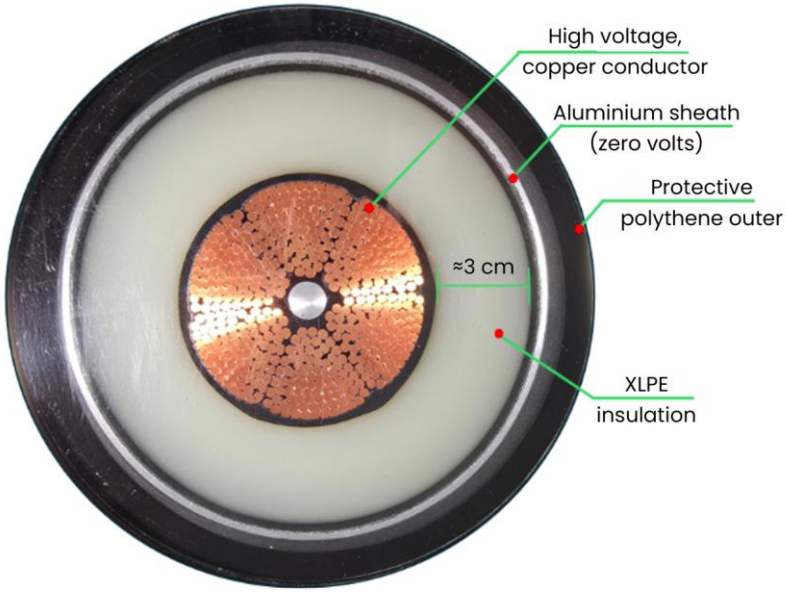


Figure 5.5: Cross-section of a 400 kV, 2,500 square millimetre copper cable with XLPE insulation

The high-voltage power transmission that takes place inside a UGC requires a highly refined design. Manufacturers must pay meticulous attention to build quality that considers all aspects of the UGC's installation and operation. During installation, great care needs to be taken when the cable is pulled into its trench and buried. Operators cannot overload the cable, either. In part, this is because of the risk of overheating. The cable's trench contains special heat-conducting backfill to keep the temperature as low as possible. Without this, unexpected loads on the transmission circuit can relatively easily raise the temperature above the normal safe maximum limit.

Underground cable impacts

Cable burial

As with OHLs, three UGC conductors (often referred to as 'cores') form a 3-phase AC circuit. Accordingly, UGCs are usually buried in threes, in a trench about 1.2 m wide and a little over 1 m deep. During construction, the area of land used is a lot wider. Special thermally conducting backfill is brought to the site to surround the cables in the bottom of the trench. This is to allow heat to dissipate and the cable's temperature to stay within limits during operation. The rest of the trench is then backfilled with the spoil originally created when the trenches were dug. Meanwhile, surplus spoil is carried away from the site to be deposited at agreed, environmentally acceptable locations. The last construction task is to reinstate the land to as close to its former condition as possible. This includes reinstating topsoil, fences, hedges and tracks.

How many trenches?

As with OHLs, because of the heat emitted by heavily loaded cables, frequently more than one conductor core is required to carry the current for each phase of a circuit. This means separating the trenches for these cores by several metres to enable the heat from each core and each trench to escape. A two-core-per-phase cable circuit would thus require six cores, or two trenches. System planners may consider installing a second circuit

alongside the first. If financially justified, it could futureproof the energy transfer capacity of the route and enhance operational flexibility and security. Such an installation would result in 12 cores and 4 trenches, as shown in Figure 5.6. The number of cores is based on the transmission capacity required from the network. More cores would therefore require more trenches and a wider swathe than depicted in the figure.

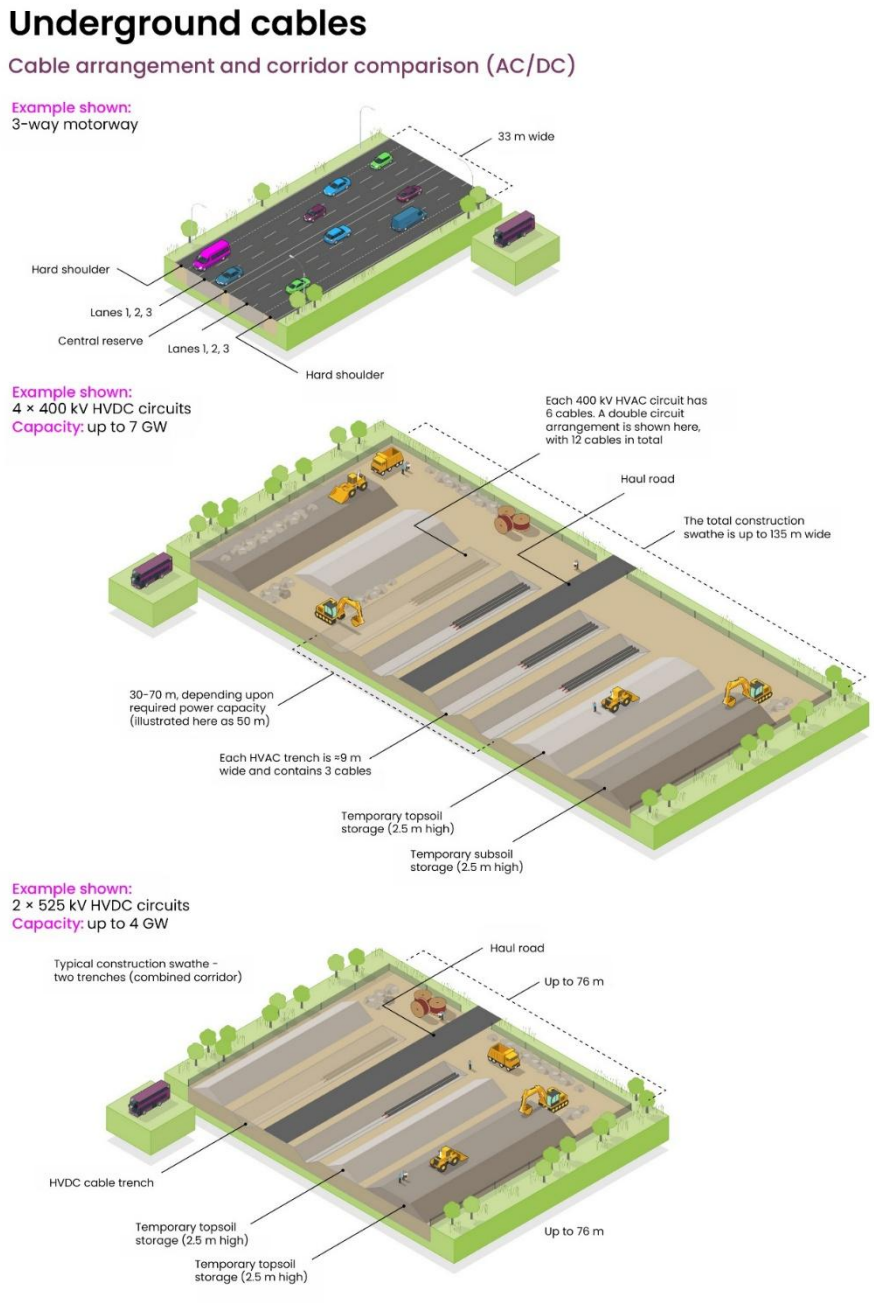


Figure 5.6: Comparisons of AC/DC cable arrangements

UGCs can be deployed in a wide range of terrains. In rural environments, they are likely to be buried. In urban areas, they may be installed in pre-prepared cable trenches. Cable ducting could also be used to protect the cables or to make installation easier. There are, however, a few circumstances where UGCs are impractical, such as in rocky or

mountainous areas. They are also inappropriate in areas of peat, rare flora or rare fauna, because during construction the areas of the swathe that are not excavated are covered with a temporary haul road and driven over by heavy loads. Whereas OHLs 'fly over' most of the land, leaving it untouched, UGCs are much more invasive. A UGC corridor is essentially a swathe dug into the countryside (Figure 5.7). For this reason, where sections of a transmission route are undergrounded with this technique, the UGC could take a different route from that of the OHL.

That said, cable construction disturbance levels may be much lower where a UGC crosses linear features of the landscape, such as roads, railways and rivers. In these cases, and where a submarine cable is brought ashore across a beach and backshore, the horizontal directional drilling (HDD) technique is frequently used to avoid disruption to the service or environment in that locality.

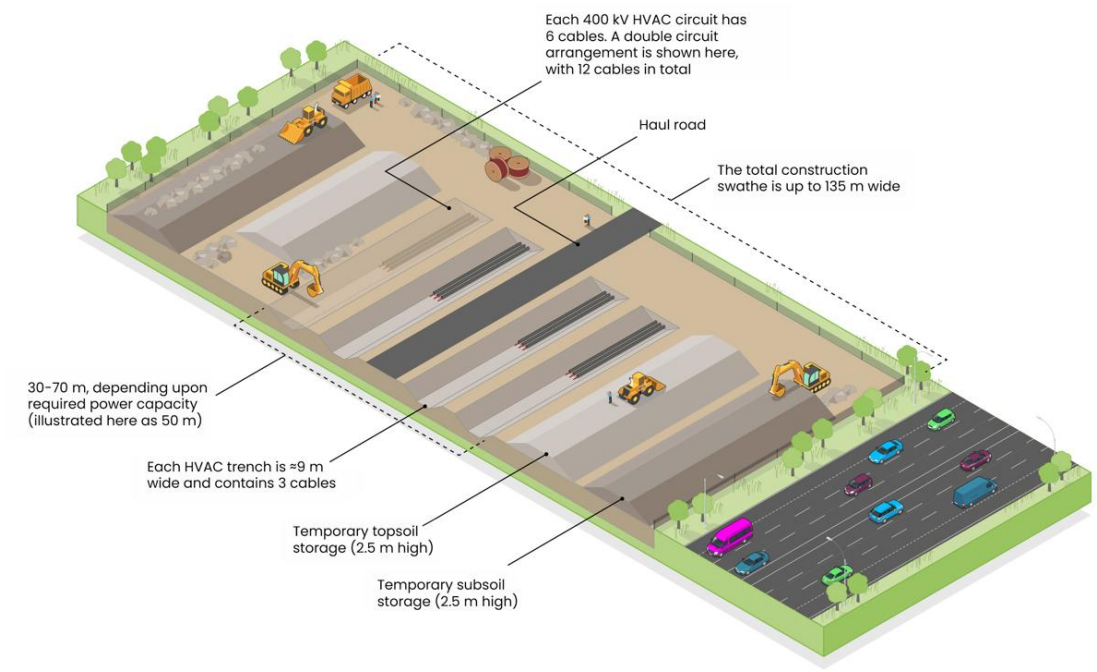


Figure 5.7: An example of a UGC route corridor

Cable tunnels

In large urban environments, a tunnel may be bored beneath the existing infrastructure to bring the transmission supplies to the heart of a city with minimum disturbance to surface activities. Locations do still have to be found for tunnel head houses and shaft access from which machines can be lowered before digging the tunnel. In this situation, a 3–4 m diameter tunnel would be constructed, and six cable cores would likely be cleated to the walls of the tunnel (one circuit = three cores) on each side. However, depending on its size and the frequency of cooling shafts and fans along its length, a tunnel may limit the power capacity of the cables. This operational limitation – along with the capital expense

of the tunnel, the need to transport and accommodate the tunnelling spoil and the operational risks of tunnelling – makes this a solution of last resort.

Visual impact

The trenches and site traffic are likely to be very visible during construction. Of course, this depends on the geographic topology and available viewing points. Once construction is completed, the land is often reinstated to its former use.

One unavoidable visual impact, however, occurs where an OHL transitions to a UGC. At each end of the UGC, a terminal tower (an extra-strong pylon) is needed to support the ends of the OHL and to connect the OHL to the UGC. This requires equipment at ground level, which is surrounded by a safety fence to create a 'sealing end compound'. Depending on the size of the compound, this installation can resemble a small substation.

While largely invisible once installed, UGCs still require some overground infrastructure. This includes large voltage control equipment and sealing end compoints, and small earthing kiosks along the route. Earthing kiosks, painted to blend into their surroundings, are 1.2-1.5 m high and 0.75-1.3 m wide (about the size of a small chest of drawers) and typically appear every kilometre along the route

Following reinstatement of the land above new UGCs, most normal farming and recreational activities can resume. However, activities within the cable swathe that penetrate the ground beyond the depth of a plough – for example building, fencing or tree growth – will be strictly controlled or prohibited. Cable routes will be inspected periodically to ensure that the circuits remain safe to the public and reliable.

UGCs create magnetic fields but no electric field. Levels of magnetic field strength are normally highest at ground level immediately above the cables. The levels fall away very quickly as the distance from the cables increases.

Underground cable operations and maintenance

Long cable lengths

UGCs in AC networks become less effective as the overall route length increases. This technical constraint means that cables over a few kilometres in length are likely to require additional equipment to compensate for this constraint. The compensation equipment can be accommodated at the ends of the cable route or, in the case of a very long cable, also part way along the route. However, network designers try to avoid very long cables because, apart from the operational complexities they may introduce, the compensation equipment is costly, takes up extra space and causes further heat loss to the environment. Such equipment can also appear similar to small substations. So, on long routes and in sensitive landscapes, locations for these features would also need to be found.

Reliability

XLPE UGCs are very reliable. They are capable of periodic overload where an urgent need arises. The degree of allowable overload, however, depends on its duration before the electrical currents are returned to normal levels. Should a cable be taken out of service

due to a fault, the circuit needs to remain de-energised until the reason has been established and its health confirmed. It can take time to locate a fault, and it can take much longer to repair than an equivalent OHL fault. This is partly because of the excavations needed before the repair can begin and partly because specialist cable jointing skills are required. Joints are also required at regular intervals, which can affect reliability, particularly for longer circuit lengths. These factors, alongside the need to store spare sections of cable long term, inevitably increase costs. At the same time, extended repair outages risk impacting the network's ability to supply its customers – a risk that can be offset by installing two circuits at a time.

Underground cable costs

As for OHLs, separate cost estimates can be made for the capital procurement, installation and lifetime operating costs – that is, the operational costs plus the costs of heating losses in the UGCs over their operating life. There are two key variables in assessing these costs:

- the design rating of the equipment (its maximum power-carrying capacity)
- the anticipated loading of the equipment (the amount of electricity it is expected to carry most days)

Table 5.4 outlines the indicative build plus lifetime operating costs per kilometre of a typical UGC in Great Britain.[21]

Table 5.4: Typical lifetime costs* of a 400 kV UGC of low, medium and high rating

Route length	Low rating ≈2,500 MW	Medium rating ≈5,000 MW	High rating ≈7,500 MW
3 km	£16.71m/km	£28.08m/km	£39.32m/km
15 km	£14.85m/km	£25.00m/km	£35.01m/km
75 km	£13.9m/km	£23.61m/km	£33.14m/km

*Costs based on 2023 prices.

Of these estimated costs, the split between construction capital and lifetime operating costs varies very little between 88% capital and 12% operating costs for the short route, low-rating UGCs to 86% capital and 14% operating costs for the long route, high-rating alternative.

In practice, unit cost estimates can vary widely, depending on many external factors associated with specific projects. However, the figures given in Table 5.4 represent a central, or 'expected', estimate in each case.

21 'A comparison of electricity transmission technologies: Costs and characteristics' (2025)

The operating cost and whole-of-life comparisons, in particular, rely on the assumptions about the amount of load that the circuits will carry over the course of their lives. In practice, these figures will vary from project to project.

Survey finding
44% of respondents told us they would find it acceptable to pay higher energy bills to fund UGC cables if they cost significantly more than OHL – 30% said it was not acceptable, with 25% neutral in their opinion.

Offshore transmission

HVDC technology enables much longer offshore transmission routes than HVAC.

Most of the British electricity network is onshore, but there is a history of relatively short-distance offshore links dating back many years. These links use subsea high-voltage alternating current (HVAC) cables to connect smaller islands to mainland Britain.

Using HVAC technology, the practical route length over which subsea cables can operate reduces as their system voltage rises. At 400 kV, unless special costly compensation equipment is installed along the route, the technical limitations of modern AC transmission cables restrict the route length to around 80 km (or up to 150 km if additional compensation is installed).

Increasingly, offshore high-voltage direct current (HVDC) links are being used to transmit power over longer distances. This technology enables long-distance transmission of electricity using underground and subsea cables without the AC restrictions mentioned above. Great Britain's transmission system now has three operational offshore HVDC transmission links, with two more links currently under construction (EGL1 and EGL2) and a further two (EGL3 and EGL4) in their planning phase. Additional links may also be developed to meet future network needs.

HVDC does not stop there. In addition to the HVDC links within Great Britain's transmission system, HVDC interconnectors (international transmission connections) link Great Britain to Northern Ireland, the Republic of Ireland, France, the Netherlands, Denmark, Belgium and Norway. Closer to home, the first offshore wind farm to connect to Great Britain's transmission network using HVDC technology was Dogger Bank A in 2023, with more such connections now under construction. As interconnectors and offshore wind farm HVDC links are owned, built and managed separately from the main transmission network, they are not described further in this section.

Can we put all new transmission offshore?

Offshore transmission works well for long-distance, point-to-point connections, such as national or international links where no intermediate stops are needed. Rather like a cable car connecting two mountain tops, it provides a quick and easy path between peaks but cannot serve the community in the valley between them.

Onshore transmission, by contrast, is more like a motorway that can have junctions at towns and villages along the way. It can be routed close to major demand centres, link up

with existing infrastructure in multiple places along the route and provide shorter connections.

There is also a physical constraint present in offshore transmission. When planning and constructing an offshore transmission link, every onshore connection requires cables to cross beneath the shoreline and coastal strip, and suitable landing points are scarce. Much of Britain's coastline is environmentally fragile, affected by erosion or home to communities already impacted by previous infrastructure developments. Offshore transmission cables are also much harder and more expensive to repair if something goes wrong, and so having too many offshore links potentially increases wider system security.

The economics compound these physical constraints. Connecting offshore HVDC cables to the onshore AC network requires a large and expensive warehouse-size converter station at every junction point. Providing intermediate connections along an offshore route would therefore mean multiple such stations – which would have a significant impact on coastal communities, not to mention additional cost. There is one operational multi-terminal HVDC link in northern Scotland and further multi-terminal links planned. However, the technology to efficiently control HVDC systems with more than two terminals is still maturing, which makes multi-point offshore networks more difficult to build and operate than point-to-point options.

For these reasons, offshore transmission, be that domestic or international, is best reserved for long-distance, point-to-point links. Simply put, it cannot replace a substantial onshore transmission network to serve inland towns and cities.

Why do HVDC cables work better than HVAC cables over longer distances?

When electricity is conducted through a wire (also known as a 'conductor'), the wire gains an electrical charge. This charge grows the higher the voltage, the longer the route and the closer the wire is to the ground. The greater the charge, the more current is needed to create it. This charging current (or 'reactive current') is 'parasitic' – that is, it exists all over the transmission network but does not contribute to transmitting power itself.

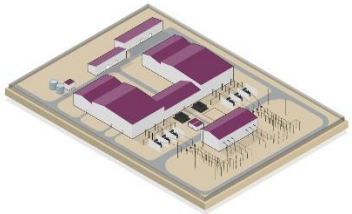
With HVDC, operational voltage does not change much after startup, so this parasitic charging current occurs only once, and briefly, at switch-on. After that, it has no further impact on the connection's ability to transmit real power, even over very long distances.

For HVAC, it is a different story. In the UK and Europe, voltages alternate between positive and negative 50 times a second, so parasitic charging current flows continuously. Since the heating effect of any current limits the real power a connection can carry, charging current reduces the capacity delivered to customers.

For 400 kV AC OHLs in Great Britain, charging currents are small because the conductors are high above the ground. But 400 kV AC cables sit barely 3 cm from the earth or seabed through their insulation, so charging currents are much higher. As a result, underground and subsea cables over certain lengths may need special compensation equipment to stop their charging currents overwhelming the useful power flowing through the connection.

The infrastructure

The main components of an offshore HVDC transmission link are:

	**Underground and subsea HVDC cables along the chosen route of the HVDC link** As well as the main underwater sections, the route includes a cable landfall site (where the cable goes from underwater to underground) and a section of UGC to get to the converter station.
	**An HVAC/HVDC converter station** This is positioned at each end of the HVDC link to convert AC electricity to DC electricity at one end of the link and to convert it back again to AC (known as 'inverting') at the other end of the link. This also includes an AC substation to step up (increase) the voltage of the AC electricity to match the transmission network.

	**HVAC OHLs (or UGCs)** These connect the converter stations to a new or existing substation on the onshore AC network.

For more information, refer to the earlier section key elements of the electricity networks system.

Offshore transmission impacts

Onshore environmental surveys and offshore seabed surveys are conducted to help find the best conductor route and the best locations for converter stations. They typically take 1–2 years to complete. The project must secure planning permission, environmental and regulatory consents, and land rights to proceed. This 'permitting process' runs alongside the surveys and typically takes 4-5 years to complete. Once the route is selected and all permits and rights are secured, the construction of the converter stations can begin. Then the subsea and UGCs are installed.

Converter stations

Construction of converter stations

It takes about 3–5 years to build an HVDC converter station. The process requires:

- earthworks to clear and level the site
- construction of the main buildings to house the sensitive converter equipment

These first two steps take about 2–3 years to complete. They are then followed by:

- installation of the converter equipment
- connection of the converter to the AC substation and to the HVDC cable
- commissioning the whole connection

These last three steps take about 1–2 years to complete.

Additional landscaping of the site is also carried out to help the converter station blend into its environment.

Visual impact and land take of converter stations

The converter stations and the associated infrastructure that is required where the cable makes landfall are the most noticeable visual aspects of offshore solutions. The ground area of each HVDC converter station can be as large as Wembley Stadium, being typically between 4 and 9 hectares (roughly the size of 5-14 football pitches) – see Figure 5.8. The size varies, depending mainly on the capacity of the transmission link and the HVDC technology used. Converter stations that use voltage source converter (VSC) technology

generally have a much smaller footprint compared with those that use line commutated converter technology.[22]

There is one converter station needed at each end of the HVDC cables. This means the total area taken up by the converter stations is 8-18 hectares (11-25 football pitches) per HVDC link. Because each subsea HVDC link has a lower maximum capacity than an OHL, multiple HVDC links and pairs of converter stations are needed to provide the equivalent capacity to a high-capacity onshore route.

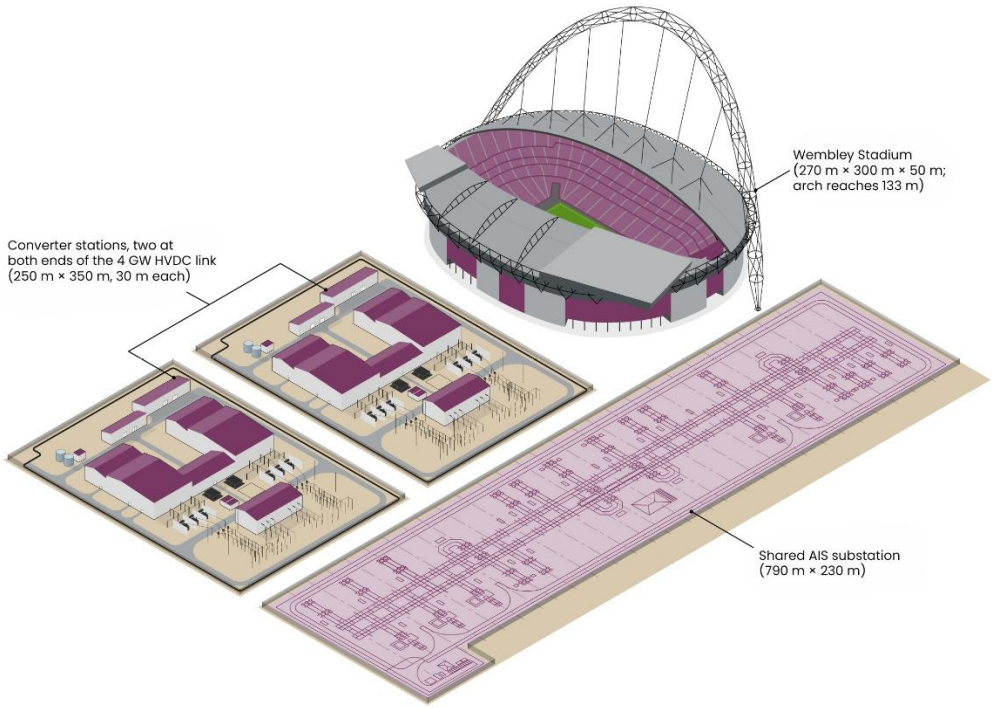


Figure 5.8: Comparison of converter links and associated infrastructure with Wembley Stadium

Two 2 GW converter stations and their associated HVDC links would provide a transmission capacity of 4 GW, which is at the lower end of the 2.5–7.5 GW capacity of a double-circuit, 400 kV OHL. The plan view of two such converter stations (bottom left, each nearly 9 hectares, or 22 acres) and their associated substation (top, around 15 hectares, or 38 acres) are compared with that of Wembley Stadium (6.8 hectares, or 17 acres). In practice, the converter stations may be sited separately from the substation.

As well as the converter stations, new or expanded substations and OHL or UGC routes are needed to connect the converter stations to the onshore transmission network.

In summary, the visual impacts of onshore and offshore transmission are different. Although the majority of an offshore transmission route is invisible from land, it still requires significant visible onshore infrastructure.

22 National Grid, High Voltage Direct Current Electricity technical information (2010)

Noise impacts from converter stations

Some equipment will produce noise, usually a steady 100 Hz hum, along with various degrees of related higher pitches.[23] The noise's impact depends on several factors, including the proximity of neighbours and ambient noise levels. However, the local council is obliged by the Environmental Protection Act 1990 to protect people from any industrial or machinery noise source that is "prejudicial to health or a nuisance". Substation designers and constructors take this into account, controlling noise before it becomes a nuisance or prejudicial to health.

First, developers compare background sound levels in the proposed development area with the predicted noise levels from the new converter station. If the noise could cause an unacceptable impact to nearby properties, designers are required to find ways to reduce the noise. This typically involves:

- choosing quieter equipment during the design phase
- enclosing remaining sources of noise within noise-insulating buildings, known as 'acoustic enclosures'
- ensuring buildings or earth banks adequately screen the affected properties from the source

Then, once a converter station is built and operating, monitoring is carried out to check that agreed noise limits are being met. Planning conditions usually require this monitoring to continue over the long term.

Installation of subsea cables

To find the best route for subsea cables, surveyors consider the depth, seabed conditions, obstacles and other infrastructure the cables must navigate. They also consider the presence of sensitive habitats and fisheries.

Offshore cables are installed on the seabed by special cable-laying vessels (Figure 5.9). These use large turntables to store the cable while sailing from the manufacturing plant to the installation site. Some cable-laying vessels can carry 11,000 tonnes of cable on two turntables (Figure 5.10). This is equivalent to some 130–160 km of 525 kV HVDC cable (about the distance from London to Birmingham). Future ships will be able to have up to twice this capacity.

23 SSEN-Transmission (2011)



Figure 5.9: A typical cable-laying vessel

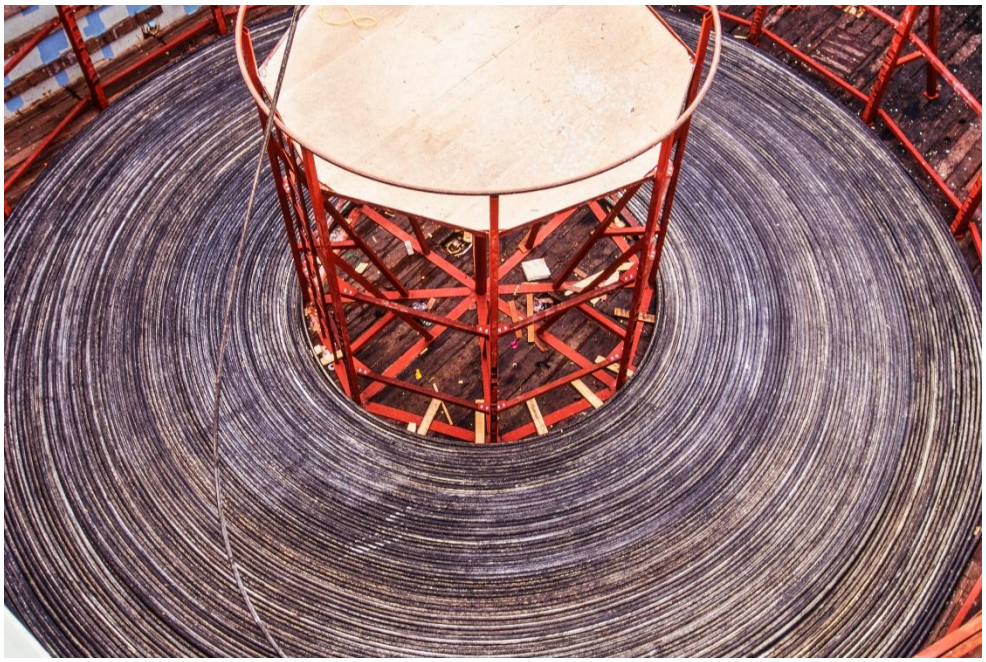


Figure 5.10: A cable-laying turntable

There are two stages to installing the cable: laying and burial. The cable must be buried to protect it from damage by fishing vessels, ships' anchors and seabed movement. There is also the risk of cable damage as it is transferred from the ship to the seabed. This is particularly high when cable is laid in rough seas, making cable laying dependent on weather conditions. That is why cable installation usually takes place during the summer months. The cable installation process usually takes up to a year to complete, depending on the length of the route and the method of burial. One or two vessels are used to install the cable. The cable is unwound from its turntable into the sea. A plough, pulled along the

seabed by the cable-laying vessel, buries the cable as it is laid (Figure 5.11). Sometimes, the cable is laid on the seabed by one vessel and then buried by another vessel using a robot trencher. The trencher crawls along the seafloor behind the vessel.

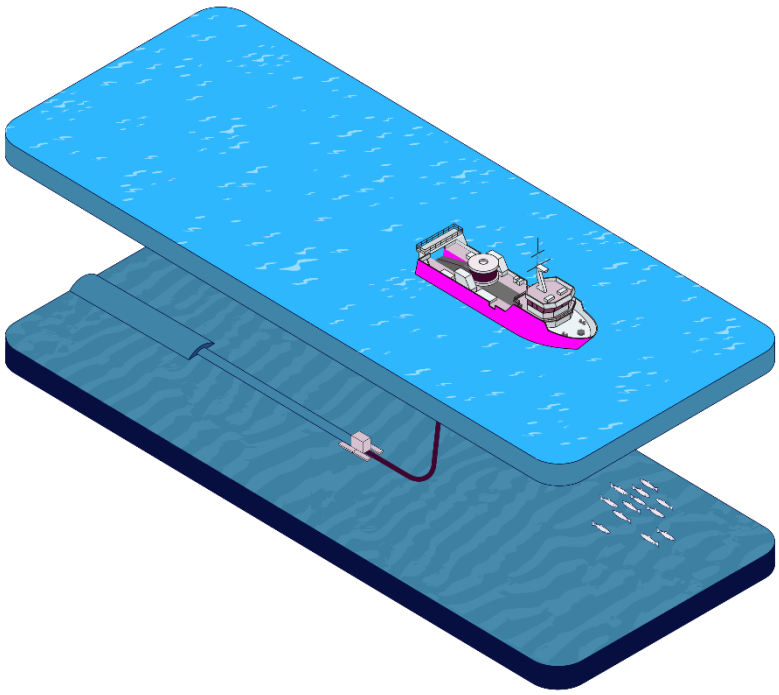


Figure 5.11: A subsea cable being laid and buried using a plough

In ideal conditions, cable laying can progress at up to 5 km per day. Often, two cables can be laid at the same time. Once the stock of cable onboard is used up, the vessel returns to port to reload.

The cable is buried to a depth of 1–4 m below the surface of the seabed using either a plough pulled by the vessel or a robot trencher crawling along the seafloor. If the target burial depth is not achieved or if the seabed is too hard for burial, the cable is laid on the seabed then additional material, such as concrete mattresses or a graded rock berm, covers the cable to protect it.

Impacts on maritime activities

The primary impacts from subsea cables are largely associated with commercial fishing. During the construction phase, a corridor is set up around infrastructure to prevent damage to the cables before they are buried. This corridor may be extended to the operational phase, depending on how vulnerable the cable is to damage from fishing gear. Bottom trawlers operating nearby are required to lift their fishing gear when crossing the corridor.

Environmental impacts from subsea cables

During construction, disturbance of the seabed creates noise and sediment, which can temporarily affect local ecosystems and marine life. Trenching cuts a narrow furrow into the seafloor, displacing seabed-dwelling animals such as worms and shellfish. It also stirs up sediment in the water. Standard mitigation includes:

- identifying and avoiding sensitive habitats, such as seagrass beds and reefs
- careful route selection
- scheduling work to fall outside of sensitive periods, such as fish spawning or marine mammal breeding seasons
- choosing the least disruptive burial method

Once in service, cables produce a magnetic field in the surrounding water and seabed. Some species – in particular sharks, skates and rays – have a highly developed sense for electric and magnetic fields. They use this to find prey, avoid predators and to navigate during migration.[24]

Slightly different fields are produced depending on whether the cables are carrying alternating current (AC) or direct current (DC). HVAC cables generate a magnetic field that constantly switches direction, while HVDC cables produce a steady magnetic field. Scientists have found a range of responses from marine life to magnetic fields, from mild attraction or avoidance to no observable change in behaviour. Importantly, field strength falls away sharply with distance, so any effects are generally confined to the area immediately around the cable.

Burying cables beneath the seabed protects them and helps to reduce the field that reaches marine life above them. Combined with avoiding sensitive habitats, burial is an effective way to limit the overall impact on the marine environment.

Bringing the cables onshore

Cables can be installed either by digging an open trench across the beach and intertidal zone or with trenchless techniques, such as horizontal directional drilling (HDD). HDD involves drilling a curved underground route from an inland starting point, beneath the shoreline, that emerges on the seabed some distance offshore (Figure 5.12). Activity at the drill rig site may last for several months, after which the cable is then pulled back through this tunnel, leaving the shoreline largely undisturbed.

These specialised installation methods are used to protect the coastline and avoid disturbing sensitive habitats where the cable makes landfall.

24 sciencedirect.com

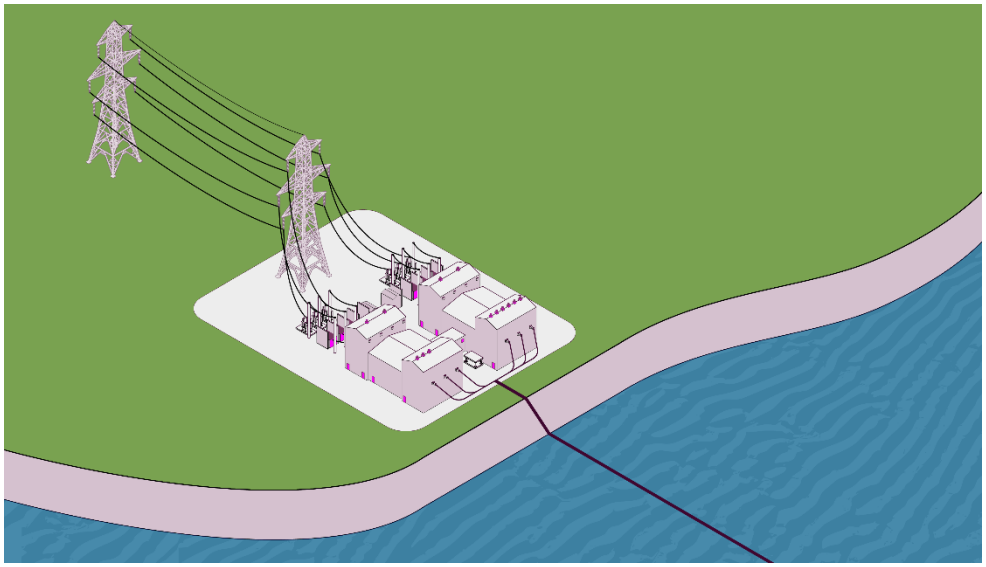


Figure 5.12: Landfall of offshore cable

The precise exit point on the seabed varies but is typically around a kilometre or more from shore, at a depth safely below the lowest tide level. This ensures the cable is well protected from wave and tidal activity.

The subsea cables are pulled through protective ducts installed within the drilled tunnel and connected to the onshore UGCs at a 'transition joint bay'. The transition joint bay is located a short distance inland above the high-tide mark.

During construction, temporary access tracks may be created to connect the landfall work area to the existing road network. Site activity includes:

- setting up a construction compound
- drilling operations
- cable installation and pull-in
- deliveries of materials and equipment
- reinstating the site once work is complete

Installing underground HVDC cables from the landfall to the converter station

Cable installation occurs section by section. It begins by clearing vegetation and excavating topsoil. A temporary construction compound is established for each section to accommodate site facilities for workers and to store equipment. A haul road is also installed along the entire length of the section. This may include temporary culverts and bridges. Diversions for local traffic are put in place where necessary.

Difficult obstacles that require ducted and trenchless crossings, such as roads, rivers and buildings, are dealt with first. Then the cable trench is dug for either direct burial or ducted cable installation, followed by the construction of 'joint bays' (where lengths of cable are joined together). The cable is installed and then lengths are joined together in the joint bays. Finally, the cable is tested and commissioned. This means the cable is ready for operation, and then temporary site works can be removed and the land reinstated.

For more information, read the section on underground cable impacts.

Offshore transmission operation and maintenance

One of the main differences between offshore and onshore infrastructure is in how they are operated and maintained. All assets require routine maintenance to make sure they operate with high availability and safety. When things do go wrong, assets need to be repaired as soon as possible to prevent disruption to customer supplies.

Issues with routine subsea cable maintenance

The routine maintenance of subsea cables is complicated by their inaccessible location and the need to use specialist vessels and equipment.

Subsea cables are designed to last for at least 40 years. However, like any infrastructure, they require maintenance to maximise their useful life. The most challenging aspect of routine maintenance is ensuring the cables are buried to the correct depth, to protect them from damage. A remotely operated vehicle (ROV) is used to check the cable's burial depth. ROVs can only be operated during good weather and are expensive, as they also require specialist vessels to carry them. In the event of a fault, subsea cables are much more difficult, time-consuming and expensive to repair than OHLs.

Conversely, routine maintenance of OHLs is much quicker and cheaper, because the infrastructure is more easily accessible.

Faults on onshore OHLs can be easily located using visual inspection with the aid of drones or helicopters. Repairs are carried out by the transmission operator's (TO) repair crews and specialist contractors. Faults with OHLs can usually be repaired in a few hours or days, depending on the problem – although serious structural issues may take weeks to resolve.

Operational benefits of offshore transmission

Unlike conventional onshore transmission, offshore transmission using HVDC VSC technology can help to stabilise AC grid power flows. Each end of the HVDC link connects to the grid through a converter station. The converter station houses controllable power electronics. It can adjust the size and direction of the power flow, which can help support the network when there is a fault, providing the sending end of the link has enough supply.

Some modern converter designs can also provide other network services. One of these mimics the stabilising effect that large spinning turbines offer the grid. Because more coal- and oil-fired power stations have closed down, there are fewer of these turbines connected to the power supply system. This has led to an increase in the number of synthetic inertia services being used to support network stability. Such systems can also contribute to electricity system restoration services, helping re-energise the network after a major outage.

Offshore transmission costs

The whole-life cost of offshore transmission using HVDC cables is approximately five times more expensive than onshore transmission using OHLs.[25]

However, asset costs are not the only consideration when determining the most economically beneficial option. All transmission projects are highly complex. However, because there are fewer restrictions on routeing infrastructure offshore compared with onshore, it can be less complex to approve offshore transmission. Therefore, re-routeing part of a new transmission link offshore may enable new transmission capacity to be delivered many years earlier than would otherwise be possible.

Despite onshore options being less expensive to build, offshore transmission projects have still been selected for progression alongside, or in place of, onshore options.

Why is more expensive offshore transmission used?

Offshore options can be more expensive than onshore options to build, but they are also much quicker to build. This means they can increase network capacity earlier – and so avoid several years of costly network constraints – than onshore routes. This saves money in the long run. Building cheaper onshore routes slower increases the route's overall operational cost. So even though offshore routes are more expensive to build, they can work out cheaper overall.

Substation technologies

Introduction to substations

Substations are the 'junction boxes' of the electricity network. Every OHL, UGC or subsea cable starts and terminates at a substation. Every transmission connected generator (renewable or fossil fuel), transformer, energy storage facility and converter station connects into a substation.

Every substation therefore needs to provide:

- places for circuits to connect (busbars)
- equipment to control, protect and monitor those circuits
- voltage and current transformers

Substation sizes vary significantly, depending on the number of circuits they need to connect and any relevant customer connections. Regardless of the technology they house, they often have a similar basic layout. One typical design, known as a 'double busbar layout', gives the system operator flexibility and reduces unnecessary system complexity.

25 Cost includes construction, operation, maintenance and allowance for energy losses.

A double busbar substation layout contains two busbars: a main one and a reserve one. A busbar is a single bar that joins all of the connections present in a substation. By having two busbars, the substation can be set up to run in different modes. It can choose to either join all the connections together or run them as separate groups.

All substations also feature circuit breakers that can switch the circuit on or off during a fault or for routine maintenance. Corresponding pairs of busbar selector disconnectors enable every circuit to connect either to the main or to the reserve busbar. Busbar circuit breakers and busbar disconnectors also provide further connection flexibility.

Transmission switchgear operates at very high voltages (in Great Britain the transmission voltages are 400 kV, 275 kV and 132 kV), and there are two alternative technologies that can provide the substation functions at these voltages: air-insulated switchgear (AIS) and gas-insulated switchgear (GIS) – see Figure 5.13.

- AIS provides enough space around the high-voltage equipment for the air to act as an effective electrical insulation. AIS is normally installed outdoors, in a gravelled switchyard.
- GIS encloses the high-voltage equipment in sealed metal enclosures that contain very pure, pressurised insulating gas. GIS has a smaller footprint than AIS and is normally installed indoors to protect it from pollution.

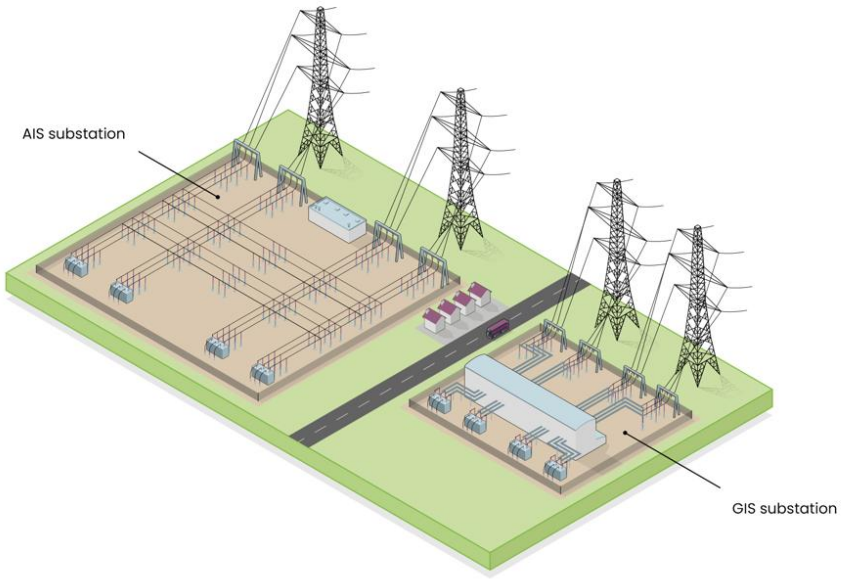


Figure 5.13: GIS and AIS substations

These two technologies perform identically from a network function perspective, but they have different characteristics. Each technology has different benefits, depending on the situation. Table 5.5 outlines the main differences between the two switchgear technologies.

Table 5.5: Comparison of AIS and GIS technologies.

	AIS	**GIS**
Insulation type	Air	Gas
Usual location	Outdoors	Indoors
What it looks like	Openair layout Equipment, connections and support structures may be visible through a palisade fence or hidden behind a wall	Metal clad or architectural building Some connections visible outdoors
Land use	Higher land-take than GIS Frequently used in rural areas	Significantly smaller footprint Suitable for tight or constrained sites
Planning and visual impact	Potentially more visible than GIS because equipment is outdoors and dispersed Depending on location, tree and shrub screening can be highly effective	Usually easier to screen since the switchgear is concentrated within a single building The building itself can be taller than AIS
Construction and delivery	Can take around two years to build.	Can take up to two years to build Equipment is factory assembled and installed indoors Requires different construction activities
Maintenance and repairs	Easy to access Simple to repair Failed components can often be replaced individually	Very reliable Requires less maintenance than AIS Major repairs require specialists
Future expansion	Simpler to extend if land is available Less tied to the original manufacturer Less impacted by obsolescence	Compact design means it is easier to reserve space Future extensions rely heavily on the original system manufacturer and, potentially, on access to strategic spares
Environmental considerations	Larger site preparation and more civil engineering works	Less ground disturbance

	Outdoor equipment exposed to weather and pollution	Gases used often have an extremely strong greenhouse gas effect in the case of leaks, though modern GIS increasingly uses sulfur hexafluoride (SF_6) free gases SF_6-free gases reduce potential environmental impact
Cost	Lower equipment costs More extensive civil engineering works	Higher equipment costs Less civil engineering works

Air-insulated switchgear

Historically, substations have used AIS to insulate high-voltage circuits. AIS ensures there is enough air space around each set of equipment to avoid electrical flashovers between them.

Infrastructure

AIS transmission substations are almost always installed outdoors. Where salt spray from the sea or industrial pollution can damage the substation's porcelain insulators, they are installed indoors. This keeps the equipment, especially the insulators, clean and able to operate reliably.

The minimum distance between neighbouring 400 kV OHLs is 3–7 m. All high-voltage components also need to be isolated from the ground. A common design practice is to support all high-voltage metalwork on tall porcelain insulators (≈2.5–3 m long). These porcelain insulators are placed well out of reach on concrete or steel supports. This means the equipment can be safely inspected when it is live and operating.

The highest components of AIS can be some 15 m above ground level. Its foundations and gravel make up the floor of the substation.

AIS substation impacts

Construction and land take

Extensive land preparation and civil work, weather dependency of equipment installation, and extensive on-site testing and commissioning affect construction installation time.

The components of an AIS substation need to be spaced far enough apart for air between them to effectively insulate each from its neighbour. One typical layout used in many installations includes a double busbar, associated connections, and access for people and equipment to install and maintain the equipment (Figure 5.14). Its length, however, depends on the number of connections (bays).

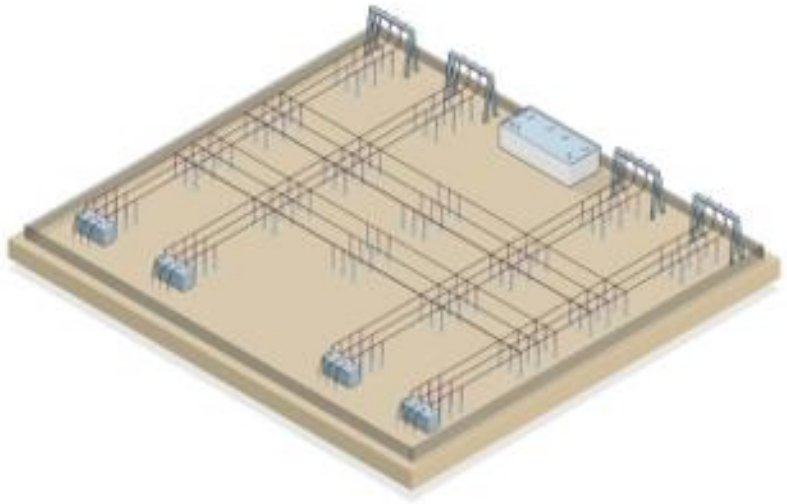


Figure 5.14: A 400 kV AIS substation

Visual impacts

In a rural environment, the substation is usually enclosed by a 3 m high security fence. The structures within this vary in height, reaching up to about 15 m. The substation's largest structure is the control building, which typically measures 30 m × 30 m. The steel tanks of the transformers can be 7 m long and 10 m high. Each transformer would have a cooling fluid (like oil) conservator tank mounted a further 1–3 m above and to the side of the main transformer tank.

Close up, these are large structures, so substations are typically provided with visual screening, such as raised earth berms, trees and other shrubbery. Earth berms provide a further benefit. They can screen or deflect noise. In urban and suburban environments, 400 kV AIS substations are more likely to have high security walls. These can also mitigate transformer noise.

Acoustic noise

Most substation equipment operates quietly. A momentary exception to this would be the circuit breakers. Opening or closing them can create a sharp 'clunk' or 'snick', which is audible to those close by. However, circuit breakers do not generally operate every day. Also, this noise may not be noticeable anyway, depending on ambient sound.

Transformers and, if installed, some reactive compensation equipment create two types of persistent noise. There is a continuous 100 Hz hum when the equipment is in service and the noise from transformer and compensator cooler fans. The transformer cooler fans will operate more often during hot weather or periods of high demand. Compensator cooler fans may operate at any time. Both fans normally have graduated controls. These ensure the fans start gently and quietly, minimising the amount of time that full speed (and therefore the loudest) operation is required.

Maintenance

For a transmission network to be effective, it must be highly reliable. This means being subject to regular inspections, remote monitoring, trend analysis and periodic maintenance.

AIS equipment is normally installed outdoors and is easier to inspect, access and repair than GIS equipment. Normally, faults can be located quickly and replacements found easily from a range of suppliers. This makes AIS straightforward to maintain over its lifetime, particularly where maintenance teams need to respond rapidly to unplanned outages. GIS equipment does, however, require less frequent maintenance than AIS equipment.

Because components from different manufacturers can often be integrated, AIS substations are relatively straightforward to modify or expand, assuming sufficient land is available. However, a full end-of-life substation replacement can present a particular challenge for AIS technology. This is because there needs to be enough adjacent land on which to build the replacement substation while the existing substation continues to operate.

Gas-insulated switchgear

GIS technology is the newer of the two main technologies used to build substations (Figure 5.15). The equipment itself is typically more expensive than AIS technology. However, it has an advantage over AIS as it requires a much smaller footprint.

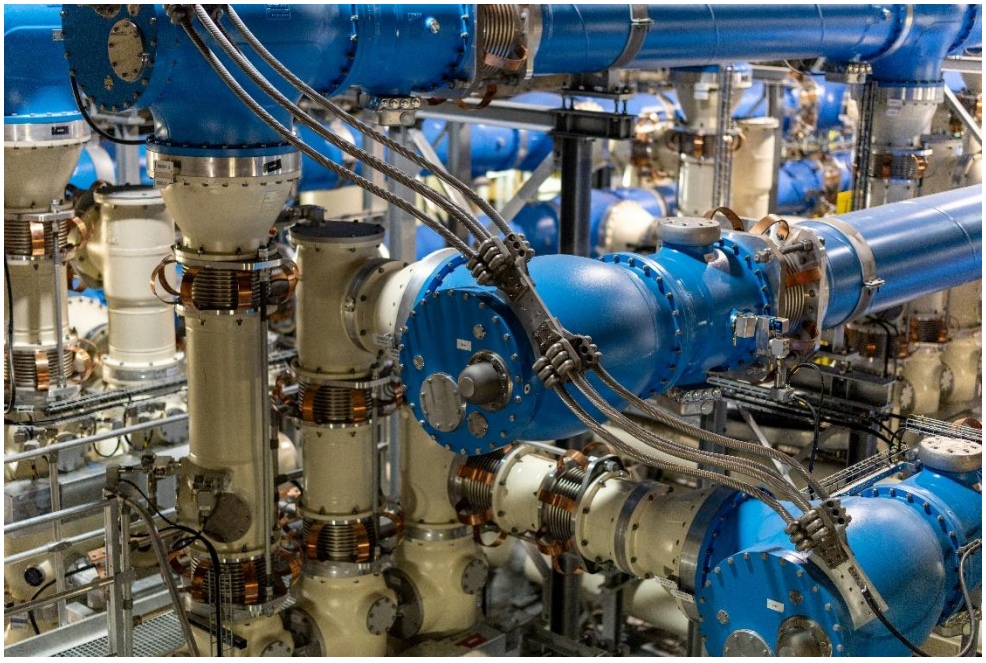


Figure 5.15: Example of GIS. Source: National Grid

The infrastructure

Some gases have exceptional electrical insulation performance. This was discovered almost a century ago. One of these gases, sulfur hexafluoride (SF_6), has been

commercially exploited since the mid-1950s to improve the performance of circuit breakers.

Traditionally, SF_6 gas has been used to insulate high-voltage components within GIS equipment. However, when SF_6 is released into the atmosphere, it has an extremely high global warming potential. So, in recent years, the electricity industry has been actively developing less impactful alternatives. These alternatives include fluorinated gases, such as C4FN, which are mixed with pressurised clean air. These are now beginning to be supplied by major equipment manufacturers for new GIS equipment.

It is not yet clear to what extent the less aggressive modern gases will be able to replace SF_6 in existing GIS. While the UK Government looks for ways to phase out SF_6 in electrical switchgear, network operators have already begun to install SF_6–free alternatives. This is in response to tightening environmental regulations and commitments to net zero.

Alternative gases have now been developed for use in some GIS equipment. GIS substations take advantage of these insulating properties to place the high-voltage components of the substation closer together. This reduces the ground space required to accommodate switchgear and makes the overall substation considerably more compact.

The switchgear is sealed within pressurised, precision-engineered gas enclosures, which are almost always located indoors. The design greatly reduces exposure to weather, pollution and wildlife and maintains a stable, controlled environment. It also contributes to high operational reliability.

GIS substation impacts

Construction

GIS equipment is commonly pre-assembled into standard modules and tested in the factory, which makes on-site assembly and testing processes significantly quicker. Furthermore, GIS installation happens indoors and is thus weather independent. However, the site assembly process may occasionally need to be carried out under cleanroom conditions, which can significantly increase installation times. Cleanroom conditions minimise the threat of gas zone contamination during assembly, thus increasing the switchgear's operational reliability.

Usually, there are fewer ground civil works for GIS substations, since the site area will be smaller than an equivalent AIS substation. However, civils works are extended by the need for a substantial building to house all the GIS, the gas-handling plant and the substation controls. (Substation controls are housed indoors in both AIS and GIS.)

Figure 5.16 provides an isometric depiction of a GIS substation. Note that, compared with the AIS, the GIS is installed indoors, and over a smaller ground area. Gas-insulated busbars also connect the switchgear enclosure to, for example, UGC sealing ends and OHL gantries. This arrangement occupies significantly less ground space than AIS-equivalent connections.

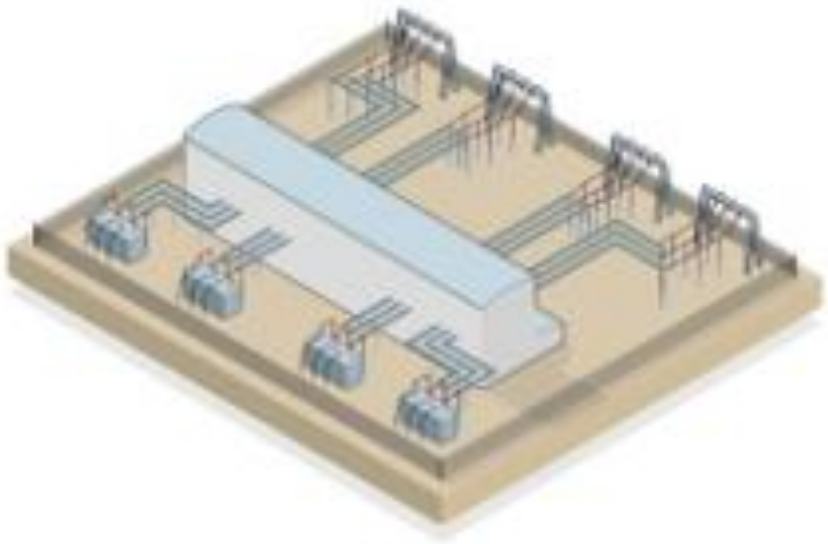


Figure 5.16: A 400 kV GIS substation

Fewer manufacturers produce GIS equipment than AIS equipment. As a result, GIS equipment lead times can be longer and more sensitive to global production constraints than those for AIS. Any future extensions to the substation must be compatible with the original design and usually supplied by the same manufacturer. This can limit design flexibility and increase dependency on the original manufacturer over the asset's lifetime, potentially increasing lead times and cost.

Land take

The enclosure for each GIS substation component is often highly integrated with neighbouring enclosures. This makes for a compact substation footprint and minimises the amount of insulating gas needed for the connections between components.

As a result, these substations generally require less land than their AIS equivalents. However, large substations use air-insulated transformers, reactive compensators and OHL substation entries, which have to be accommodated in the same manner as an AIS substation. This means the overall land saving is not so great for larger, more complex substations.

Acoustic noise

As with AIS, GIS is near-silent in operation, except for its circuit breakers. Since GIS is housed indoors, however, this provides another layer of sound reduction, and reduces the sound that would be heard outside the substation compound.

Noise from the other substation components are identical to those of an AIS substation. That is, transformer and reactor hum and the noise from cooler fans are all that will be heard.

Maintenance

Because of its enclosed design, GIS typically requires fewer routine inspections than AIS and experiences fewer unplanned failures. However, repair is a more specialised task. To access the faulted component, technicians must carefully depressurise the appropriate gas zone(s), being sure not to lose any of the gas to the atmosphere. They must then work in a scrupulously clean manner to avoid introducing any particles that would compromise the insulation within the gas enclosure(s). Repairs often depend on support from the original manufacturer, which adds further timing and cost constraints.

GIS substations are almost always installed indoors, where the clean, dry atmosphere helps to prevent any impact from environmental damage or degradation. As such, GIS substation maintenance interventions occur less frequently than their AIS equivalents. However, when intervention is required, either for maintenance or repair, the procedure can potentially be complex and time consuming, as the switchgear may be built in a much more compact configuration. This often means that other equipment needs to be removed before the relevant item can be accessed. Also, because they are close to the work area, adjoining bays may need to be de-energised for safety purposes.

Future GIS substations may have greater build flexibility. This is to align with the new Electricity Design Transmission Principles (EDTP), which give guidance on incorporating sufficient space around the switchgear and gas insulated busbar (GIB) equipment.[26] This enables lifting operations to be carried out without impacting other circuits. The EDTP also recommend incorporating enough gas zones within the switchgear to enable interventions during single bay outages.

Refurbishment and replacement

Individual asset refurbishment or replacement may be more difficult for GIS than for AIS. This is mainly because GIS substation components are highly integrated, which restricts accessibility. Neighbouring equipment may have to be taken offline to make the working environment safe around the faulty component. Furthermore, replacement components may be required to integrate precisely with existing gas zones and mechanical interfaces, making original manufacturer support critical throughout the life of the substation. This can be mitigated by good project management.

A full end-of-life substation replacement presents different challenges for each technology. For GIS, the smaller footprint can make it easier to construct a replacement facility alongside the existing one. However, the previously mentioned equipment supply lead times can become a more significant factor.

Comparing AIS and GIS substations

The purchase cost for GIS equipment is normally higher than for an AIS equivalent.

AIS substations comprise individual items of air-insulated equipment, with few physical interdependencies between them – and do not require indoor installation. Most of the

26 Electricity Transmission Design Principles (2025)

substation equipment has multiple alternative suppliers and, apart from the control and protection panels, there is no benefit to factory pre-assembly and testing.

Conversely, the gas enclosure for each GIS substation equipment item is highly integrated with its neighbouring enclosures. This makes for a compact substation footprint and minimises the amount of insulating gas needed for the connections between components. This integration, however, requires precision-engineered enclosures with high-integrity gas seals between each enclosure and its neighbours. To help minimise the regular maintenance requirements of GIS substations, they are typically housed within a dedicated building, and so initial equipment costs are consistently higher than those for AIS.

Figure 5.17 compares the land footprint of AIS and GIS substations.

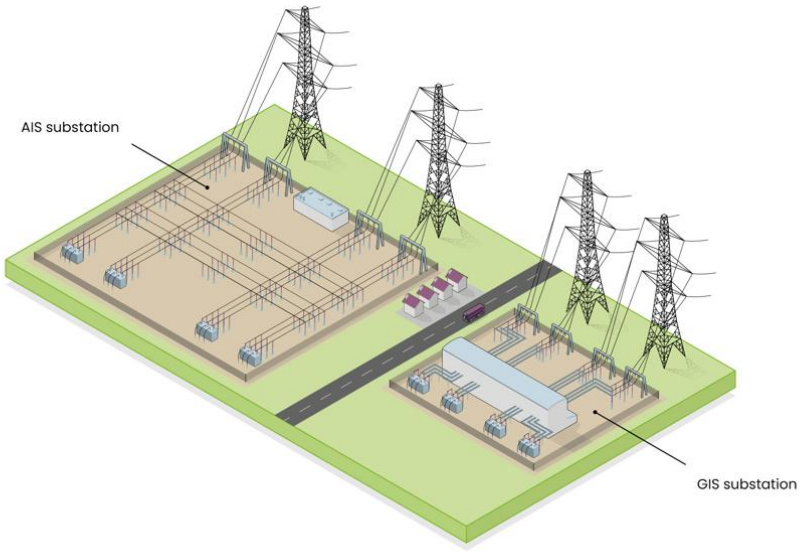


Figure 5.17: Comparison of AIS and GIS substation land footprint

Overall lifetime costs

Although the purchase cost for GIS equipment is normally higher than for the AIS equivalent, the overall lifetime cost comparison between the two technologies will depend upon many factors. These include location, land-take and planning conditions, the cost of land, the need for a substation building, the extent of earthworks, lifetime carbon costing, biodiversity net gain costs and projected maintenance and repair costs. Table 5.6 outlines the non-exhaustive factors that shape the lifetime cost of both technologies.

Table 5.6: Factors shaping AIS and GIS lifetime costs

	AIS	GIS
Land availability and price	Often requires a larger land requirement than GIS substations	May avoid the need to purchase or prepare large plots
Planning and consent risk	Good siting, use of landform and terrain can influence how size affects planning and consenting Often a very site-specific factor	Good siting, use of landform and terrain can influence how size affects planning and consenting Often a very site-specific factor
Need for buildings and earthworks	Typically requires more extensive civil works and small buildings to house protection and control equipment, and for staff welfare Height not an issue	Typically requires less building and civil works Requires a much taller building than the switchgear inside (to accommodate a crane to lift equipment in and out of the substation assembly)
Lifetime carbon costs	Embodies carbon mainly from its civil works and concrete foundations	Embodies carbon partly from its civil works and concrete usage Has a higher emphasis on manufacturing materials
Maintenance and repair regimes	Requires more routine maintenance Routine maintenance requirements decrease over time as equipment designs mature	Requires less routine maintenance Maintenance is more dependent on original manufacturer support
Biodiversity net gain requirements	Larger AIS sites may require extensive landscape and ecological mitigation	Equivalent GIS sites require less mitigation, because they are smaller

All these project-dependent factors mean that purchase cost alone is unlikely to be the deciding factor. The relative benefits of faster delivery, reduced land take and lower planning risk can make GIS the more efficient choice in some cases. AIS, on the other hand, can often be cost effective for large, rural sites, especially where screening of visual impact is straightforward.

6. Glossary



AC	alternating current
AIS	air-insulated switchgear
CATO	competitively appointed transmission owner
CBA	cost–benefit analysis
CP30	Clean Power 2030
DC	direct current
DESNZ	Department for Energy Security and Net Zero
DNO	distribution network operator
DSO	distribution system operator
EN-5	National Policy Statement for electricity networks infrastructure
ETDP	Electricity Transmission Design Principles
FES	Future Energy Scenarios
GIS	gas-insulated switchgear
GW	gigawatt
HDD	horizontal directional drilling
HVAC	high-voltage alternating current
HVDC	high-voltage direct current
km	kilometre
kW	kilowatt
kWh	kilowatt-hour
MW	megawatt
NESO	National Energy System Operator
NPF4	National Planning Framework 4
OFTO	offshore transmission owner

OHL	overhead line
ROV	remotely operated vehicle
SF_6	sulfur hexafluoride
SSEP	Strategic Spatial Energy Plan
TO	transmission owner
UGC	underground cable
VSC	voltage source converter
XLPE	cross-linked polyethylene

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