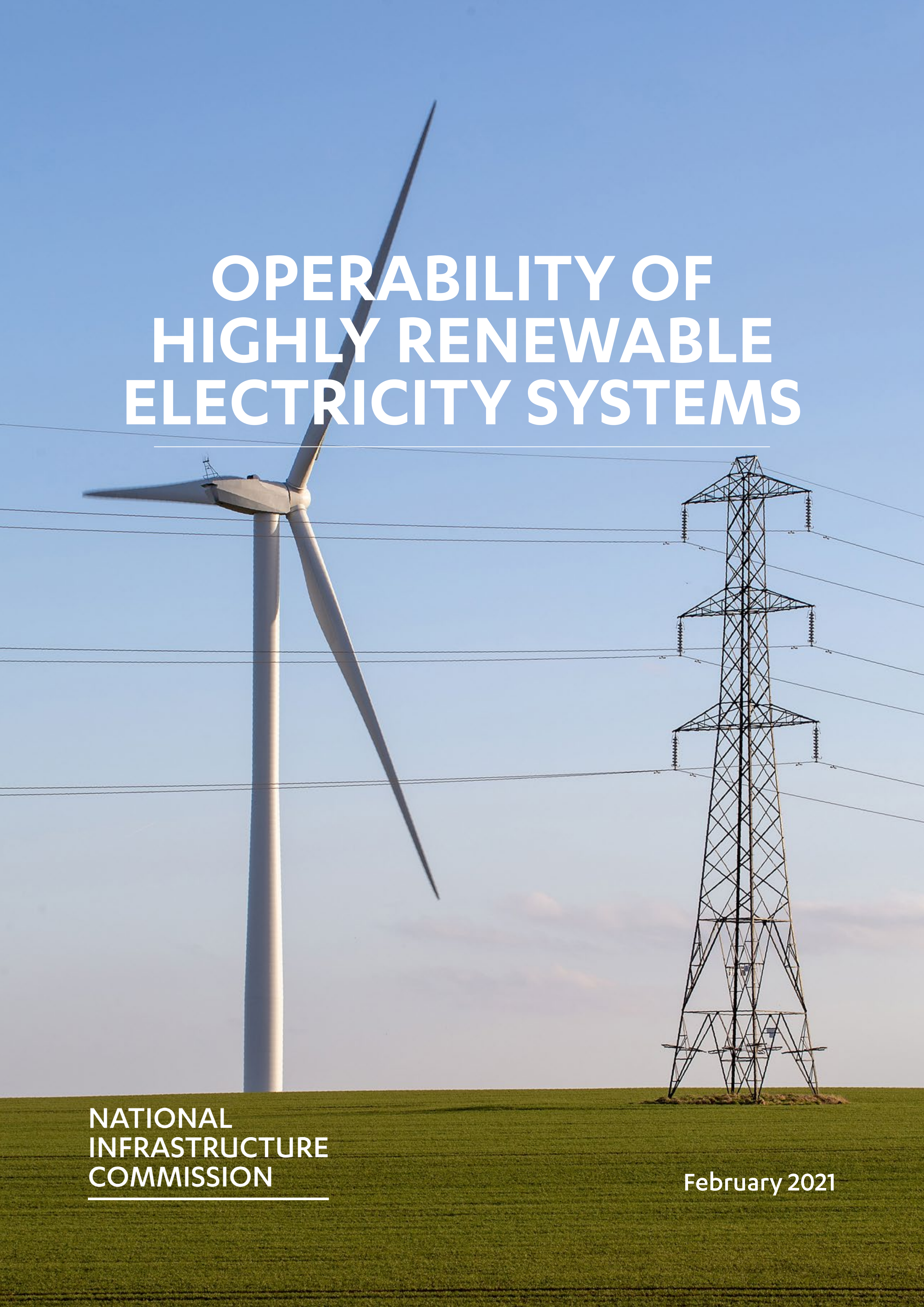

OPERABILITY OF HIGHLY RENEWABLE ELECTRICITY SYSTEMS

NATIONAL
INFRASTRUCTURE
COMMISSION

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Contents

The Commission

The Commission's remit

The Commission provides the government with impartial, expert advice on major long term infrastructure challenges. Its remit covers all sectors of economic infrastructure: energy, transport, water and wastewater (drainage and sewerage), waste, flood risk management and digital communications. While the Commission considers the potential interactions between its infrastructure recommendations and housing supply, housing itself is not in its remit. Also out of the scope of the Commission are social infrastructure, such as schools, hospitals or prisons, agriculture, and land use

The Commission's objectives are to support sustainable economic growth across all regions of the UK, improve competitiveness, and improve quality of life.

The Commission delivers the following core pieces of work:

- a National Infrastructure Assessment once in every Parliament, setting out the Commission's assessment of long term infrastructure needs with recommendations to the government
- specific studies on pressing infrastructure challenges as set by the government, taking into account the views of the Commission and stakeholders, including recommendations to government
- an Annual Monitoring Report, taking stock of the government's progress in areas where it has committed to taking forward recommendations of the Commission.

The Commission's binding fiscal remit requires it to demonstrate that all its recommendations for economic infrastructure are consistent with, and set out how they can be accommodated within, gross public investment in economic infrastructure of between 1.0% and 1.2% of GDP each year between 2020 and 2050. The Commission's reports must also include a transparent assessment of the impact on costs to businesses, consumers, government, public bodies and other end users of infrastructure that would arise from implementing the recommendations.

When making its recommendations, the Commission is required to take into account both the role of the economic regulators in regulating infrastructure providers, and the government's legal obligations, such as carbon reduction targets or making assessments of environmental impacts. The Commission's remit letter also states that the Commission must ensure its recommendations do not reopen decision making processes where programmes and work have been decided by the government or will be decided in the immediate future.

The Commission's remit extends to economic infrastructure within the UK government's competence and will evolve in line with devolution settlements. This means the Commission has a role in relation to non-devolved UK government infrastructure responsibilities in Scotland, Wales and Northern Ireland (and all sectors in England).

The Infrastructure and Projects Authority (IPA), a separate body, is responsible for ensuring the long term planning carried out by the Commission is translated into successful project delivery, once the plans have been endorsed by government.

The Commission's members

Sir John Armitt CBE (Chair) published an independent review on long term infrastructure planning in the UK in September 2013, which resulted in the National Infrastructure Commission. Sir John is the Chair of National Express Group and the City & Guilds Group. He also sits on the boards of the Berkeley Group and Expo 2020.

Professor Sir Tim Besley CBE is School Professor of Economics and Political Science and W. Arthur Lewis Professor of Development Economics at the LSE. He served as an external member of the Bank of England Monetary Policy Committee from 2006 to 2009.

Neale Coleman CBE is a co-founder of Blackstock Partnership. He worked at the Greater London Authority from 2000-2015 leading the Mayor's work on London's Olympic bid, the delivery of the games, and their regeneration legacy. Neale has also served as Policy Director for the Labour Party.

Professor David Fisk CB is the Director of the Laing O'Rourke Centre for Systems Engineering and Innovation Research at Imperial College London. He has served as Chief Scientist across several government departments including those for environment and transport, and as a member of the Gas and Electricity Markets Authority.

Andy Green CBE holds several Chair, Non-Executive Director and advisory roles, linked by his passion for how technology transforms business and our daily lives. He chairs Lowell, a major European credit management company and has served as Chair of the Digital Catapult, an initiative to help grow the UK's digital economy.

Professor Sadie Morgan OBE is a founding director of the Stirling Prize winning architectural practice dRMM. She is also Chair of the Independent Design Panel for High Speed Two and one of the Mayor of London's Design Advocates. She sits on the boards of the Major Projects Association and Homes England.

Julia Prescot is a co-founder and Chief Strategy Officer of Meridiam and sits on the Executive Committee of Meridiam SAS. She has been involved in long term infrastructure development and investment in the UK, Europe, North America and Africa. Since 2019 she has sat on the board of the Port of Tyne.

Bridget Rosewell CBE is a director, policy maker and economist. She served as Chief Economic Adviser to the Greater London Authority from 2002 to 2012 and worked extensively on infrastructure business cases. She has served as a Non-executive Director at Network Rail and Non-executive Chair of the Driver and Vehicle Standards Agency. She is currently Chair of the Atom Bank and the M6 Toll Road.

Executive summary

Managing the electricity system is becoming more complex. The increasing diversity of sources, and the potential for growing demand for electricity, creates new challenges to maintaining a stable system. But these challenges can be addressed. Current evidence provides confidence that a highly renewable electricity system, for example one with over 70 per cent generation from renewables, can maintain secure and reliable electricity without adding significantly to the costs of generating electricity.

The Commission has recommended that government should ensure that the electricity system is running with at least 65 per cent per cent renewable generation by 2030. This will ensure maximum advantage is taken of recent cost reductions in renewable generation and put the country on the pathway to a highly renewable electricity system. Continuing with rapid deployment of renewables now is the best way to deliver the net zero consistent electricity system the country needs whilst keeping costs low for consumers.

The GB electricity system was designed to operate with the types of generation that have traditionally been connected like coal, gas, or nuclear. Renewables operate differently from these traditional forms of generation which is introducing new operability challenges that need to be addressed. Often these challenges are not accounted for in electricity system modelling which has led to concerns being raised that deploying lots of renewables will make a highly renewable system either unviable or that such a system would be prohibitively expensive to manage. To maintain stability on the system will require services to be purchased that were previously provided by traditional forms of generation. These requirements are already being met, through actions taken by the Electricity System Operator (ESO) and can continue to be met using approaches that will not significantly add to the cost of managing the electricity system.

There are existing technologies that can provide the system with what it needs to maintain secure and reliable supply. Some of these technologies, such as synchronous condensers, have been deployed on electricity networks for decades. Others, such as virtual synchronous machines, have not yet been developed for at scale deployment, but offer scope for a lower cost solution. So, while it is not clear at present what mix of technologies will best deliver the critical operability needs for the system, the evidence is clear that they can be met.

Therefore, the engineering constraints, whilst real, should not undermine the deliverability of the Commission’s recommendation to move towards a highly renewable electricity system.

Overview of the electricity system

The electricity system has four primary components: generation of electricity from plants and technologies; storage of some of the electricity produced; transportation of electricity along a network of overhead and underground cables; and households and businesses that use the electricity. The cost of the system is around £30 billion per year, paid for through consumers' electricity bills. This covers the cost of operating and maintaining system assets and also less visible costs such as policy support for deployment of new generation plant and financing the investment in assets on the system.

Over time this system has evolved. Great Britain has moved from a reliance on coal to gas to running a system with a growing proportion of renewable technologies in the mix. It is essential that electricity supply is always able to meet demand, which fluctuates on a second by second basis. It is the ESO's role to keep the system in balance.

Key challenges of operating the electricity system

The electricity networks are a complex engineering system. Alongside matching supply with demand there are engineering needs the electricity system must meet to ensure reliable flows of power. There are four key system needs that must be provided: inertia, short circuit level, voltage control and system restoration.

The ESO takes actions to ensure the safe and efficient movement of power across the network. The system services delivered to meet these needs have largely, to date, been met by synchronous generators, namely coal, gas, and nuclear plants. Increasing levels of variable renewables, and therefore a reduction in synchronous generation on the system, is resulting in additional actions being needed.

The changing nature of operability

Over the past decade the proportion of electricity from variable renewables has risen dramatically. In 2019 variable renewable generation provided 38 per cent of the electricity generated in the UK. This increase in variable renewables output, and resulting reduction in synchronous generation, has led to a reduction in the system needs naturally met by the plants connected to the electricity system. Further actions have, and will continue, to be needed to ensure system needs are met.

Connecting more variable renewables changes the electricity system in other ways too. Renewables will be sited in different locations than traditional generation and the pattern of generation will be less predictable as it is linked to weather patterns.

Alongside increasing deployment of renewables there are other trends in the energy sector that will impact the operability challenges on the system, such as the potential for increased reliance on fewer but larger generators and changing patterns of electricity demand as the heat and transport sectors increasingly rely on electricity and our climate warms resulting in increased summer demand for air conditioning.

How these challenges can be met

A highly renewable system may exacerbate the challenge of meeting the key system needs, but these challenges can be addressed through deploying a range of available technologies and developing new ones. Uncertainty exists on what level of services will be required in the future and what the best mix of solutions will be. However, evidence provides confidence that the additional cost will be small.

Government and the ESO can take actions to ensure that costs of operating a secure and reliable system remain reasonable by continuing to support market approaches to deploying viable technological solutions, removing any barriers to deploying the necessary technologies and developing novel solutions.

The UK is not alone in its journey towards a highly renewable electricity system. This provides an opportunity to learn from the experiences of others and to impart its own knowledge on the development of electricity systems globally.

Overview of the electricity system

The electricity system generates power and transports it to homes and businesses right across the country. The four primary components of the system are: generation, storage, networks, and consumers. Whilst the electricity system began over a century ago, it's far from a settled system. Instead, it has been in a state of constant evolution – this will continue to be the case as new low carbon infrastructure is deployed to meet the net zero target.

The electricity system

The electricity system comprises of four main components: generation plants which create electricity; storage which allows the electricity to be used when needed; networks which transport it; and consumers who use the electricity.

Electricity generation capacity consists of the large, and small, infrastructure assets that generate electricity. In the 1990's the main types of generation in Great Britain were coal, natural gas, oil, and nuclear. But over the past twenty years new renewable technologies such as offshore wind, onshore wind, solar and biomass have been deployed at scale. From the perspective of electricity grid management, generators have historically been split into two categories:

- **Synchronous generators**: these are plants that produce power that is synchronised with the frequency of the electricity network. They generate power through rotating alternators through an electromagnetic field, which are connected to turbines that are all linked to spin at the same speed. Synchronous generators include coal, gas, nuclear, hydro, and biomass.
- **Variable renewables**: these are technologies that are dependent on weather patterns to generate and are connected to the electricity networks via power converters. This means that they are not currently naturally linked to the frequency of the grid. This has consequences for the system services they can provide. Variable renewables include offshore wind, onshore wind, and solar generators.

Historically, coal and natural gas supplies have acted as a form of energy storage. Plants using these fuels to generate electricity have been able to manage their electricity output to meet demand requirements. But as the system decarbonises these fuels will no longer be used. Instead, the system will require storage of electricity using electrochemical storage such as batteries, mechanical storage such as pumped hydro plants or flywheels, and potentially low carbon gases such as hydrogen.

Electricity networks take electricity from the power plants where it is generated, to homes and businesses where it is used. The physical assets making up the networks, which have an estimated value of about £40 billion, include more than 800,000 kilometers of overhead and underground cables.

- Most of the electricity is moved through the network as alternating current as this makes it easier to step up or down the voltage in transformers and increases the efficiency with which power can be transported over long distances.
- The frequency of the networks refers to how quickly the alternating current completes one cycle. The European networks are operated at 50 Hz, or 50 cycles per second.

In Great Britain, these electricity networks are split into two categories:[1]

- The transmission network transports high voltage electricity from generators across the country. There are three transmission operators (TOs) – National Grid Electricity Transmission, Scottish Power Transmission, and Scottish Hydro Electric Transmission.[2] The transmission network tends to operate at 275kV and 400kV. This is where most large generators such as gas plants, nuclear power stations or offshore wind farms connect. Some large industrial consumers are also connected to the transmission network.
- The distribution networks carry electricity from the high voltage transmission grid to most consumers. The vast majority of the networks are operated by one of 14 Distribution Network Operators (DNOs), who are owned by six different companies.[3] There are also 13 licensed Independent Distribution Network Operators (IDNOs) that own and operate small localised networks serving areas such as new housing estates. The distribution network operates at or below 132kV.
- Transformers are used to step down the voltage levels when electricity flows between the transmission grid and the distribution grids. Some small-scale electricity generation, such as solar PV, are also connected to the distribution network.

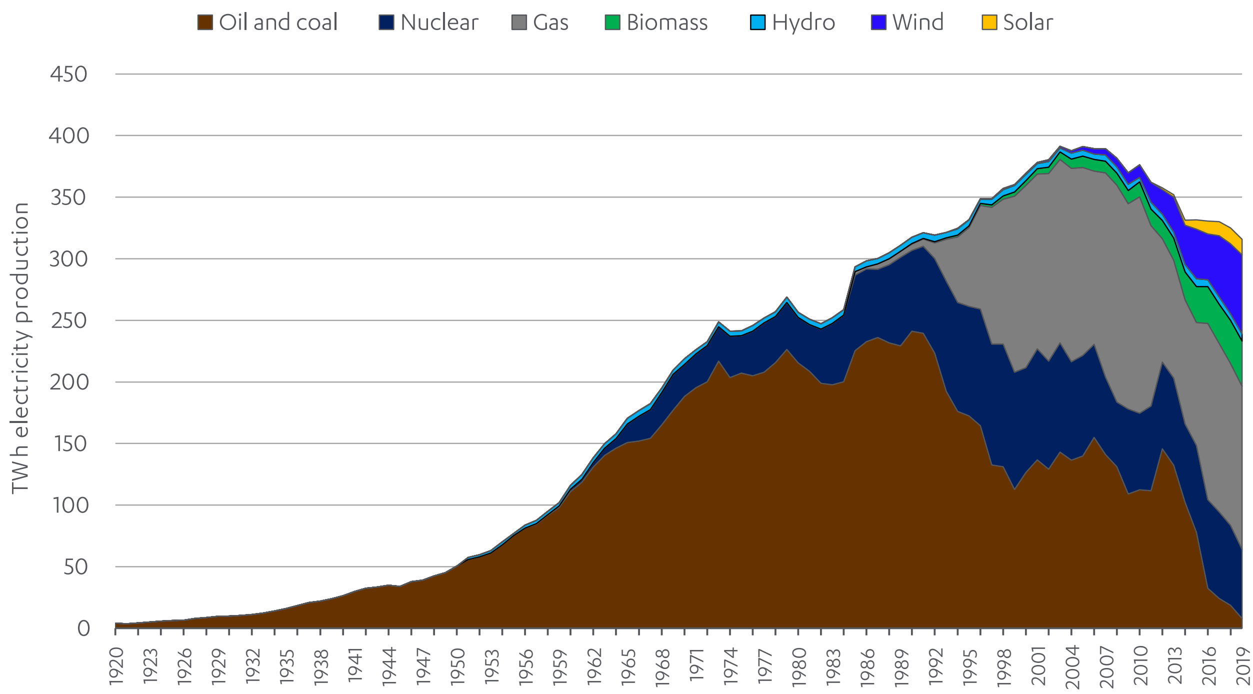
The final main component of the electricity system is consumers, which includes everyone from domestic households to larger industrial users. Consumers take electricity - primarily from the distribution network - and put it to use in a whole range of activities and services essential to the economy. Ultimately, it is consumers who pay for the whole of the electricity system through their bills.

How the electricity system has evolved over time

The electricity system is in constant transition. A hundred years ago the UK had a very small electricity system that only served around 850,000 customers. Over the next 30 years it grew to a national network running almost exclusively on coal power. From the 1960s to the 1990s the system continued to grow to meet new demands. And whilst coal still provided the majority of the power, nuclear became a significant component in the mix. Privatisation and repeal of the European Community 1975 Directive, which prohibited the use of gas in power stations, brought the 'dash for gas' in the 1990s.[4] This saw around 2 GW of gas plants being built each year from 1990 to 2000.[5] This new gas capacity helped to meet the ever growing demand but also began to push coal off of the system.

Change has been no less radical over the past 20 years, with concerted policy action helping the drive towards a lower carbon system. Renewables, largely onshore wind, offshore wind, solar and biomass, have increased from only 3 per cent of generation in 2000 to around 38 per cent in 2019.[6] Demand has also fallen in recent years due to the changing nature of the economy and improvements in the efficiency of electrical products. This has resulted in coal being pushed almost entirely off of the system – in 2019 it made up only 2 per cent of generation.[7] This has led to a significant drop in the carbon emissions intensity of the system – in 2000 this was approximately 420gCO2/kWh but fell to 177gCO2/kWh in 2019.[8]

Figure 1: Electricity generation in the GB power system over the last century[9]



Historically the electricity system has been run on centralised large infrastructure and managed on the supply side; this is changing. In recent years there has been a trend towards more distributed electricity generation and consumers playing a more active role in supplying or managing electricity. This move to a more complex system is one that will need to continue if the UK is to deliver a net zero compatible system at the lowest cost.

Balancing supply and demand

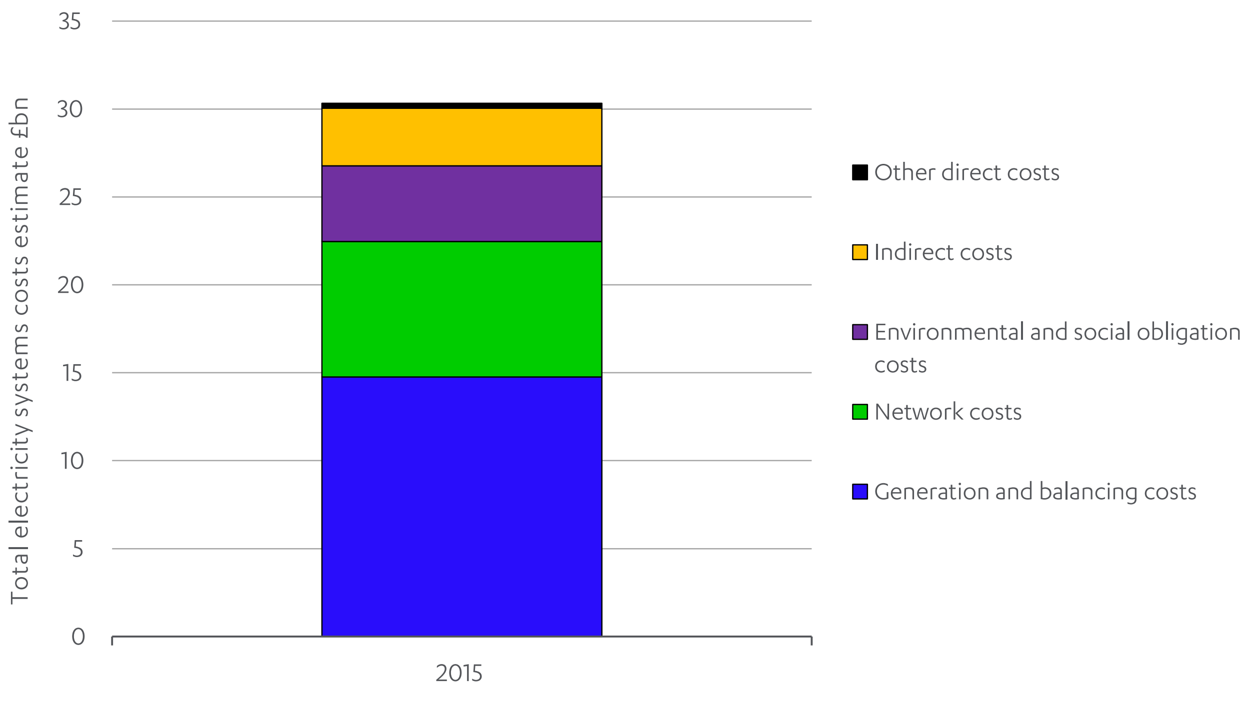
It is essential that the electricity system is always able to balance supply and demand on a second by second basis. Imbalances in supply and demand impact the frequency on the electricity networks and must be managed within safe frequency limits of 50 Hz +/- 0.5 Hz. If the frequency falls outside of these limits there is a serious risk that parts of the country may be disconnected from the network and suffer a loss of supply.

The Electricity System Operator (ESO) is responsible for managing the flows on the network and ensuring that supply balances with demand on a national level. The evolution of the electricity system has, over time, increased the volume of actions needed to manage electricity flows. The ESO has a range of tools available to balance the system, including by ensuring power stations are on standby in case of a sudden increase in demand or loss of supply. By taking real-time actions it is the ESO's role to ensure that the network operates safely, securely and efficiently.

Costs of the electricity system

The electricity system currently costs around £30 billion per year (Figure 2). A large proportion of the cost is the cost of generating electricity, which are largely made up of capital costs to build electricity plants, fuel costs for plants to run on, and fixed and variable operating expenditures of operating these plants. Different types of generation capacity have different cost profiles, for example the costs of offshore wind largely come from the capital costs required to build them, whereas the costs of gas plants largely come from the fuel needed to run them. Other components include network costs, which make up around 25 per cent of the electricity system costs, and cover the costs of financing, developing and maintaining the transportation networks and the cost of keeping the electricity system in balance. Environmental and social obligation costs, which make up around 14 per cent of total system costs, include the cost of policies which support the deployment of renewable generation.

Figure 2: Estimate of total electricity system costs in 2015 by category[10]



Key challenges of operating the electricity system

The electricity networks are a complex engineering system. Alongside balancing supply and demand, there are a range of other challenges in managing the electricity system. The system operator regularly needs to take action to ensure the safe and efficient movement of power across the network.

There are four key system needs that must be met to operate a safe and secure system today: inertia, short circuit level, voltage control and system restoration. These are not the only challenges in operating the electricity system, but they are the most important ones and are likely to remain important in a future system. There is a risk that deploying high levels of variable renewables will make meeting these needs harder. As more renewable power plants connect to the electricity system, action will need to be taken to ensure these system needs continue to be met.

Inertia

System inertia is a measure of the system's inherent resistance to changes in frequency. It refers to the kinetic energy stored in the rotating masses of turbines in generators connected to the network. These rotating masses are linked to the frequency of the network and respond automatically if the frequency changes, by instantaneously injecting or absorbing some power. The level of inertia on the system is calculated in MVA.s.

Inertia is critical for a stable network as it provides the fastest possible injection of active power when there are disturbances on the system. The more inertia there is on the system, the slower the rate of change of frequency during a system disturbance, allowing more time for additional measures, such as frequency response and reserve, to be deployed before safety limits are breached. Systems with more inertia are therefore considered more inherently stable.

Most inertia is currently provided to the transmission network by synchronous generators, most commonly large thermal plants. Typically, inertia is only provided by synchronous plants; those that are automatically coupled to the frequency for the electricity network. Not all types of generators provide equal amounts of inertia and some provide none. Capacity that is connected via power converters, such as interconnectors or offshore wind, currently provides no inertial response.

Inertia is also supplied on the distribution network. However, given the current requirements and therefore quality of monitoring on the distribution network it is not clear exactly where this inertia is coming from. Some of it will be provided by synchronous generators operating on the distribution networks, such as distributed gas generators. But some of it will also be provided by demand, where that demand has some form of connected rotating masses, for example industrial processes that use AC connected synchronous motors.

The amount of inertia the system needs is driven by a range of different factors, including:

- **The largest in-feed loss**. This is the biggest generator on the system that could trip off. Larger plants create greater frequency disturbance if they trip off of the network. Therefore, the larger the in-feed loss the more inertia the system needs to slow such a frequency deviation.

- **The rate of change of frequency constraints**. There are a range of safety protections for assets on the distribution and transmission networks. Some of these rely on reacting to how quickly the frequency on the transmission network is changing (Box 1). Therefore, the system needs enough inertia to ensure that the frequency will not change so fast that assets are tripped offline by these safety protections.
- **The amount of reserve and frequency response on the system**. Inertia doesn't solve a frequency disturbance by itself. Instead, its main role is to slow down changes in frequency. Reserve power is then needed to fill the gap. But there is a balance to be found. If the system has more reserve, then there is more room to let the frequency drop further as the system has capacity to bring it to within safety limits again. Systems with very low levels of reserve cannot let the frequency drop very far as they don't have the capacity to arrest it, so they need more inertia.

There is currently no market for providing inertia. Instead it tends to be provided as a by-product of electricity sold in the wholesale market. When the inertia on the system is too low the ESO takes action in the balancing market to re-dispatch generators accordingly. As such, there is no single estimate for the costs of inertia. However, this is changing. The ESO has recently run tenders through its Stability Pathfinder project for just inertia provision (Box 1 overleaf).

Short circuit level

Short circuit level (SCL) is a measure of the stability of the system. When it is high the system is considered strong and when it is low the system is considered weak.[11] It is a one of the key measures of system stability alongside inertia.

SCL measures the amount of current that will continue to flow on the network when a fault occurs. It provides an indicative measure of the amount of generation that can provide fast reactive power within the timescales of a voltage dip.[12] These faults can be caused by a number of factors, such as a lightning strike, a tree hitting an overhead cable or an equipment failure. During a fault the system experiences a direct connection to the earth or another part of the network.[13] When this happens large amounts of current will flow through the network to the fault. This can lead to equipment damage and importantly to safety protection failure. Like many operability issues on the network SCL is an inherently spatial issue and depends on the regional topology of the system.

Traditional synchronous generators provide a lot of short circuit support, but variable renewables do not. For example, coal and gas plants may provide around five to seven times as much fault current as wind farms.[14] Synchronous generators are able to rapidly increase their output in the event of a fault which can help to maintain the network stability. Variable renewables, due to the way they are currently connected to the network, are unable to rapidly increase their output to compensate for the fault. Without the appropriate levels of short circuit on the system it is more likely that generators will trip off in the event of a fault or system disturbance.

There are a range of different ways in which SCLs contribute to the overall strength of the system:[15,16]

- **Protection**: Much of the transmission network's protection relies on a high SCL to be able to detect faults on the system. If levels fall too low this means that various protections may not operate as quickly as they are designed to.

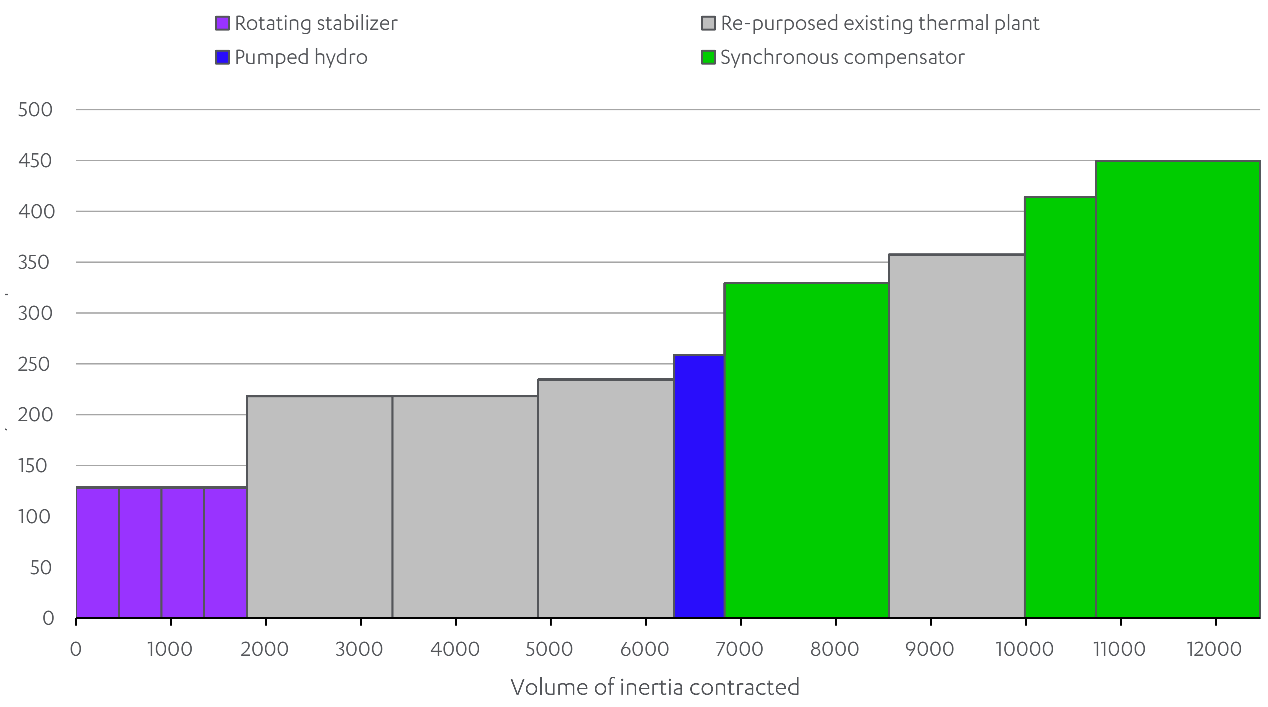
- **Voltage**: Moves faster and to a greater extent when there is a disturbance.
- **Stability**: The system may not be able to return to normal function after a disturbance within a reasonable timeframe.

Box 1: Stability pathfinder and costs for inertia and reactive power

The ESO has recently completed the first phase of their stability pathfinder, which aims to explore the value that synchronous generation provides to the electricity system and how this can be delivered from low carbon sources in the future.

The first round of the pathfinder aimed to procure inertia and resulted in 12.5 GVA.s (equivalent to 2.1 GW of gas plants) worth of contacts being awarded at a total cumulative cost of £328 million over the six years (see chart below). A range of different technologies came forward including pumped hydro and synchronous condensers. This tender has given an indication of the costs of supplying inertia separate from other services. However, given that this was an exploratory tender round costs are likely to fall in the future as competition increases, more technologies are able to compete, and revenue can be stacked with contacts for other system services.

Figure 3: Costs of inertia procured in the stability pathfinder phase[17]



Voltage control and reactive power

Like frequency, voltage levels of the electricity networks must be controlled and maintained for the safe and efficient transport of power. The transmission network must be maintained at 400/275/132 kV and kept within the limits set out in the Security and Quality of Supply Standards.

The ability to control voltage focuses on the generation or absorption of reactive power (measured in MVA). This reactive power, contrasted with active power, is used to push the active power that consumers need along the network to its destination.

A wide range of different technologies can provide or absorb reactive power. This includes some types of generation capacity alongside demand from electronic equipment such as computers and TVs. Network assets, such as capacitors or reactors, also contribute to the management of reactive power. Network assets and connected generators have provided much of the reactive power absorption and generation requirements for the network to date.[18]

Where voltage is too low, reactive power is needed to increase it, and where it is too high reactive power absorption is needed to lower it. If reactive power levels are low and voltage levels fall significantly outside the allowed limits this could lead to disconnections from the network or damage to critical equipment on the network.[19] If sufficient reactive power is not available then the ESO will need to re-dispatch generation to ensure safety which will come at a cost.

The need for reactive power depends on local conditions as well as what is happening on the rest of the network. When demand is low and so the flow of active power through the network is also low, network assets — such as overhead cables — will generate reactive power. This is when greater amounts of reactive power absorption are needed. Equally, when demand is high and there is a lot of active power flowing through the network then network assets will absorb reactive power. This is when the system needs additional provision of reactive power.[20]

Like short circuit level, reactive power provision is an inherently spatial issue.[21] Its provision is significantly more effective if it is provided near the location of the voltage control issue.

The costs of providing reactive power in 2018/19, through either dedicated reactive power services, commercial tenders or actions in the balancing mechanisms, was approximately £100 million.

System restoration

System restoration is the procedure the ESO would use to restore power if there is a total or partial shutdown of the system. This would be done by re-energising certain parts of the transmission network incrementally before bringing the whole system back online. System restoration requires generators on the system that can turn on quickly and turn on without an external supply of electricity. Not all generators can do this as many require some electrical input from the network in order to turn on. But if the whole network is down, this source of power will not be available. Therefore, not all types of generators can provide system restoration services.

System restoration requirements are locational. It is important to have system restoration capabilities at the right locations on the network. The network will need to be re-energised in a way that maintains stability as it is powered back up, which is a complex challenge. If assets are not in the right location this could lead to sections of the network being re-energised and then failing again.

Generators that provide system restoration services are primarily remunerated through availability payments, i.e. they are paid a sum to ensure that they are in a state which will allow them to activate quickly if system restoration services are required. In addition, the ESO will pay plants for testing and keeping plants ready to run. It can also provide for feasibility studies and capital investment where there is an upfront cost to make a new or refurbished plant capable of delivering system restoration services. Costs have varied considerably over recent years. In 2018/19 total costs were £49 million with approximately 70 per cent of this covering availability payments.

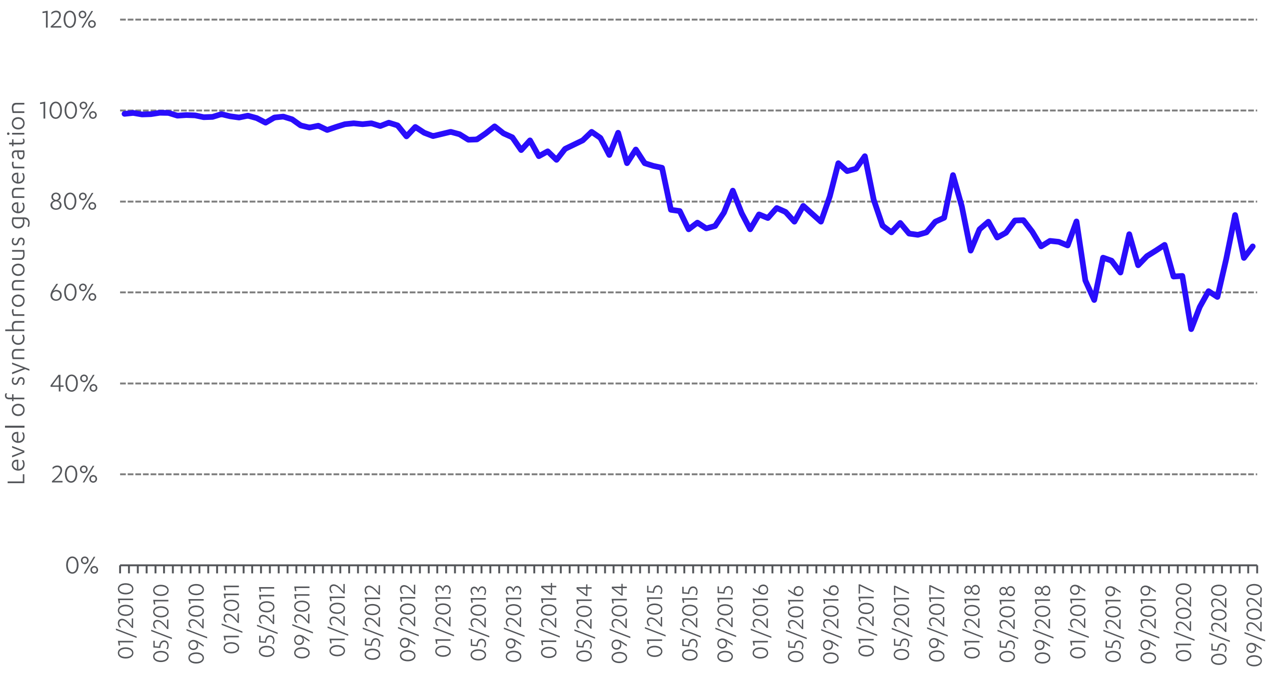
The changing nature of operability in highly renewable systems

The UK is transitioning to a highly renewable electricity generation mix and this will change the nature of some of the operability challenges that the system faces.

Over the past decade the proportion of electricity from variable renewables has risen significantly, driven by a combination of supportive policy and falling technology costs. In 2010 8 per cent of the UK's electricity was supplied by variable renewables, in 2019 this rose to 38 per cent.

As a result, the proportion of plants that naturally provide the system needs outlined has fallen. The monthly average of traditional synchronous generation, such as gas plants, has fallen from providing almost all generation in 2010 to as low as 50 to 85 per cent in 2019 and 2020.[22] On shorter timescales this has fallen even further. For example, on 22nd of February 2020 synchronous generation only met 36 per cent of generation and from 08:00 – 10:30 provided as low as 32 per cent of generation.[23]

Figure 4: Monthly averages of synchronous generation penetration[24]

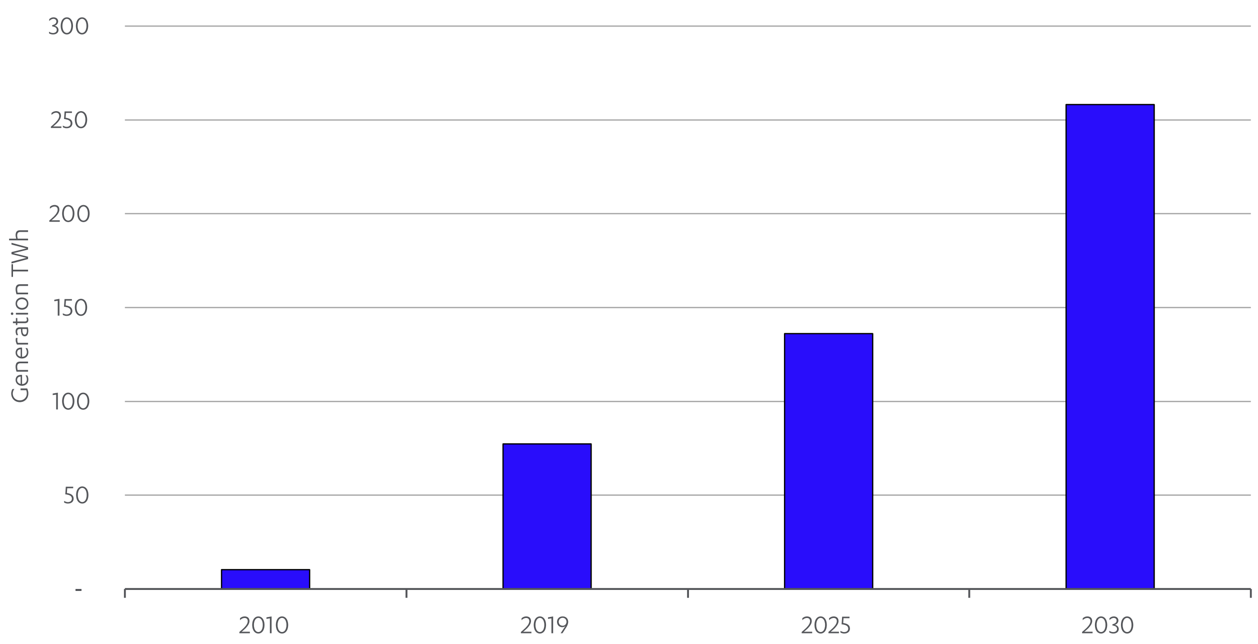


This increase in renewable generation is expected to continue (Figure 5 oveleaf). The Commission has recommended that government ensure that the electricity system is running off 65 per cent renewable generation by 2030. Government has responded positively to this, and current commitments will go a long way to delivering the needed capacity.

Beyond 2030 the future mix of generation plant on the electricity system is more uncertain, but it is likely that variable renewables will provide the bulk of the power needed. The Commission has previously modelled scenarios of up to 90 per cent variable renewable penetration by 2050. This modelling found that these systems are both cost-effective and capable of balancing supply and demand on a half hourly level.* Others, including the ESO, government, and the Climate Change Committee have also found that highly renewable electricity systems are capable of balancing supply and demand at low cost.

A system such as this can only be realised if the flexibility of the electricity system is significantly increased. This can be achieved through the deployment of technologies such as electricity storage, demand side response and interconnection. The Commission has set out recommendations for how this can be achieved in *Smart Power*.

Figure 5: Renewable generation from 2010 to 2030[25]



But the move to connect more renewables will change the nature of operability on the electricity system. Three primary factors drive this:

- **Renewables are an asynchronous form of generation**: renewables are not connected to the electricity grid in the same way as a traditional thermal plant is. In particular, they are connected via power converters and do not generate in synchronicity with the electricity. This means that they do not naturally provide many of the system services discussed above, such as inertia. As more variable renewable capacity replaces traditional thermal capacity the provision of these system services from active power generation will decrease.

* The modelling is conducted on a half hourly basis as this matched the settlement periods over which electricity is traded.

- **Renewables will be sited in different locations than traditional generation**: where generation capacity is located on the grid impacts the stress that it imposes on the network and the services that it can provide. Traditional generators - coal, gas and nuclear plants - tend to be located near the center of the electricity network. They have been located near where fuel would be available, where they provide value to the grid, or due to safety concerns in the case of nuclear. But renewables have a different set of factors that impact where they are located. They need to be sited where there is good weather resource – and in the case of offshore wind they will clearly be sited in UK waters. This can push sources of generation to the periphery of the network and changes the challenges of managing the system.

- **The operation of renewables is linked to weather patterns**: Variable renewables rely on weather patterns such as the wind and solar irradiance. And whilst weather patterns are locally predictable, variable renewables are inherently more variable that traditional fossil fuel generation. Supply will therefore fluctuate more than previously, and so the system must be able to respond faster to these changes in generation.

A summary of the impact that variable renewables may have on the key operability challenges are summarised in table 1.

Table 1: Challenges that renewables pose for key system services

System need	Impact renewables have
Inertia	Variable renewables do not naturally provide an inertia response, so without further action inertia levels will fall as traditional thermal capacity connected to the system is reduced.
Short circuit level	Whilst variable renewables do provide some short circuit level, they provide a lot less than traditional thermal plant. For example, coal and gas plants may provide around 5 to 7 times as much fault current as wind farms. So as renewables make up a larger proportion of the generation mix it should be expected that the short circuit level will fall, if all else is held equal.
Voltage control and reactive power	Voltage control is an inherently regional need. Therefore, as generation moves more to the periphery of the electricity grid, it's likely new challenges in voltage control will emerge.
System restoration	As renewables rely on the weather to generate electricity they are not currently as well suited, as thermal plants, to providing system restoration services, where it is key that capacity is able to generate reliably at any time and with no start up electricity.

Alongside increasing deployment of renewables there are other trends in the energy sector that will impact the operability challenges on the system:

- More large inflexible plants on the network: If more large nuclear plants are deployed then these place a significant inflexible load on the network. They can exacerbate operability challenges by requiring the ESO to manage the system for a bigger largest in-feed loss.

- Increased interconnector deployment: Like variable renewables, interconnectors are also an asynchronous form of generation and so do not naturally provide the system services discussed in this paper. Current interconnector capacity is expected to increase from 5 GW to around 18 GW by the mid 2020s, which could impact on some system operability considerations.26

- Increases in demand from heat and transport: New demands, for example from electrified heat and transport, will change the nature of where demands sit on the network and so regional challenges, such as managing voltage levels, may be impacted.
- Increase in distributed energy resources: If sources of generation move from predominantly being connected to the transmission network to increased volumes connected to the distribution network then this will change the power flows and assets that the ESO has to manage.

How these challenges can be met in a highly renewable system

There are a range of technologies which can be deployed alongside variable renewables that can meet the system needs required to operate a safe and reliable electricity system. Evidence provides confidence that the cost of deploying them will be low.

Table 2 overleaf summarises existing and new technologies that can provide the system needs. Some of these technologies, such as synchronous condensers, have been deployed on electricity networks for decades. Others, such as virtual synchronous machines, have not yet been deployed at scale. It's not clear what the best mix of technologies to deliver the critical system needs is, but the evidence is clear that they can be met.

Whatever the best combination of technologies is, it is likely to be a small cost relative to the overall costs of the electricity system. Today's electricity system costs roughly £30 billion per year. This is likely to increase to around £40 to 60 billion by 2050.[27] The increased cost relates to increasing the size of the system to meet the expected increase in demand for electricity as sectors such as heating, and transport are decarbonised through electrification. Indicative analysis suggests that the costs of providing inertia, short circuit level and voltage control are likely to be less than one per cent of these future electricity system costs. Costs of system restoration are less clear, but recent auctions from the ESO suggest that this is also likely to be low cost. In contrast, the estimated cost difference between alternative generation mixes is high. Analysis for the Commission has previously estimated that different generation mixes could increase or decrease costs by up to £20 billion.[28] The key challenge for the power system, from a cost perspective, is to get the generation mix right. The cost of ensuring system operability are small in relation to this.

Developing efficient markets will support the development of the lowest cost mix of technologies for providing system services. Historically, many of these system services have been procured on a bilateral basis. However, more recently the ESO has been moving towards procuring services through competitive tenders or markets.[29] Competition is proven to drive down costs and provide a route for new technologies to be deployed.

The UK is not alone in moving to a highly renewable electricity system. There is a global effort to find efficient solutions to supporting the operation of highly renewable electricity systems. Indeed, whilst the UK has been an early leader in deploying renewables many other countries have now set ambitious targets for the 2030s, for example Denmark is aiming for 100 per cent renewable generation by 2030, and Ireland and Spain are aiming for 70 per cent renewable generation by the same date. These commitments from other countries underline their confidence that it is possible to operate highly renewable electricity systems.

Table 2: Summary of provision of system services by key low carbon technologies

Technology/System needs	Inertia	Short circuit level	Voltage control and reactive power	System restoration
Existing technologies				
Synchronous condensers	✓ (Green)	✓ (Green)	✓ (Green)	✓ (Amber)
Flywheels	✓ (Green)	✓ (Amber)	✓ (Green)	✗ (Red)
Static Compensators	✗ (Red)	✓ (Amber)	✓ (Green)	✗ (Red)
Pumped hydro	✓ (Green)	✓ (Green)	✓ (Green)	✓ (Green)
Emerging technologies				
Virtual synchronous machines	✓ (Amber)	✓ (Amber)	✓ (Amber)	✓ (Amber)
Power electronics with energy storage	✓ (Amber)	✓ (Amber)	✓ (Amber)	✓ (Amber)
Hydrogen powered gas turbines	✓ (Green)	✓ (Green)	✓ (Green)	✓ (Green)
Bioenergy with carbon capture and storage	✓ (Green)	✓ (Green)	✓ (Green)	✓ (Green)
Gas plants with carbon capture and storage	✓ (Green)	✓ (Green)	✓ (Green)	✓ (Green)
Innovations in power electronics	✗ (Red)	✓ (Amber)	✓ (Amber)	✓ (Amber)

Notes: Green = mature technology that can provide service; Amber = new technology that's at early stages of deployment/ technology that can supply some of the service; Red = technology that's unlikely to supply the service.

Existing technologies

Operability challenges are not new, and there is a range of existing technologies that can meet electricity system needs. Many of these technologies can deliver system services without also providing a source of power (active power). This means they can be deployed on the electricity networks without impacting the generation mix.

If these technologies were deployed at the needed scale, they could ensure that a highly renewable electricity system would remain operable. A summary of some of the key mature technologies is given below:

- **Synchronous condensers** are a well-established technology for managing power networks. They operate by using spinning masses like a traditional thermal generator but have no electromagnetic coupling and therefore they do not provide a significant active power output. This means that they could be deployed without impacting the electricity generation mix. Synchronous condensers can provide similar system services to traditional thermal plant including, critically, high levels of inertia, reactive power, and short circuit level. They can be purpose built[30,31] or made via re-purposing existing gas turbines to run them in synchronous condenser "mode"; the same can be done with pumped hydro plants. Synchronous condensers are currently being rolled out on a number of power networks across the world to address the challenges of deploying variable renewable generation.

- **Flywheels** are a mature form of electricity storage that have been used for many decades. They store electricity as kinetic energy in spinning rotors and can provide a range of system services including inertia and voltage control. Flywheels are often deployed alongside a synchronous condenser as a form of energy storage.[32]

- **Pumped-storage hydropower plants** generate electricity by moving water from one reservoir to another at a lower altitude. Alongside generating electricity these plants can be used to provide system services such as reactive power and inertia. In comparison to many other technologies discussed here the deployment potential of pumped-storage hydropower is limited. There is currently 2.733 GW of capacity deployed, and 1.934 GW of projects currently in early stage development.

- **Static compensators/STATCOMMS** are a mature technology that are used on electricity networks to help manage voltage. Static compensators generate reactive power without also generating significant active power and can be deployed on electricity grids regardless of the electricity generation mix.[35,36]

Future technologies

Alongside existing technologies, there are several emerging technologies that could also be used to help manage system operability. These range from extracting services from renewable generation by modifying how they are connected to the grid to deploying new low-carbon synchronous generation such as hydrogen plants. The most prominent of these are discussed below:

- **Virtual synchronous machines or grid forming converters** involve using power electronics to allow the provision of a very fast frequency response, similar in speed to a traditional inertial response, from converter connected capacity. This involves implementing a different control method which allows a converter to act like a synchronous machine. This would allow plants such as variable renewables or batteries to provide some key system services.

- **Innovations in power electronics** have the potential to contribute to ensuring system operability. Power electronics is the use of semiconductor power switches to control and convert electrical power.[37] The use of power electronics will help networks increase both their flexibility and their controllability.[38] There are a range of innovations which may help manage locational constraints on the electricity networks, increase network utilisation levels, connect up different networks, provide additional voltage control and reactive power flow, potentially some inertial response and facilitate the supply of system restoration services from distributed energy resources.[39]

There are a range of pilot projects already underway in the GB power system that are applying innovative uses of power electronics for better network management.[40]

- Carbon capture and storage (CCS) involves deploying technology which can capture the CO2 that is emitted in traditional combustion plants and permanently storing this under the UK seabed. If CCS technology is deployed on gas turbines it would allow these to keep generating in a low carbon system. These plants would then continue to provide the same system services as they do today. However, even with CCS technology it is unlikely that gas plants will generate baseload electricity as other technologies will be able to generate electricity cheaper. These plants are likely to generate more flexibly which would limit their role in providing some system services.
- **Biomass with CCS (BECCS)** is the combination of biomass combusted to create electricity and CCS technology to capture and store the carbon. BECCS plants are a form of synchronous generation and would contribute similar system services to coal and gas plants. BECCS in the power sector has high capital costs but would generate negative emissions alongside electricity, which are likely to have higher value than the electricity the plant generates. It's therefore likely that it would generate baseload much of the time and could therefore provide many of these system services throughout the year.
- **Hydrogen gas turbines** could also offer many benefits to system operability. This would involve burning hydrogen, a zero carbon gas, in gas turbines to create electricity. These plants would offer the same system benefits as gas turbines do today but with very low emissions. However, similar to gas CCS plants, they are likely to play a flexible role in the future system which could limit their benefits for operability. However, having hydrogen gas turbine capacity on the networks, even if not always generating, would provide system restoration services.

Alongside these technologies, there are proposals that an electricity grid with 100 per cent renewable generation could be run in an entirely different way, so that the system needs outlined in this paper are no longer relevant.[41] This would require significant changes to the way the electricity system is run and technical changes to how generation is connected. However, this is currently a theoretical proposal unlikely to be realised in the near term.

Estimates of the costs

Relative to the total electricity system cost, the cost of meeting the four operability challenges outlined are likely to be low, however it is not possible to make a precise estimate of these costs just now. There are a range of existing technologies that can meet one or more of these challenges and many emerging technologies which have great potential, and others may emerge.

The mix of different technologies to meet the operability challenges will need to be discovered. The optimal approach to discovering this is to use markets. Use of markets can reveal the most efficient solutions.

A secondary challenge in estimating the cost is that the needs of a future electricity system are also unknown. Technical changes, such as the Accelerated Loss of Mains Programme (Box 2), will impact how much of the key services the system needs in the future. The location, scale, and type of both generation and demand is highly uncertain, making it infeasible to accurately estimate costs for any of the more regional properties such as short circuit level.

Box 2: Accelerated Loss of Main Programme

Generation connected to the distribution grids have certain safety protection functions which will trip plants offline if the rate of change of frequency (RoCoF) on the networks is too high. This is in place to protect the distribution grids and connected generators in the event of power disturbances. These protections place a constraint on how quickly the ESO can allow frequency on the transmission grid to change before plants will begin tripping offline. The ESO must ensure that there is enough inertia on the system to prevent frequency from changing faster than these constraints.

The ESO has recently launched a programme, the accelerated loss of mains programme, that will make these safety protections less sensitive. This will result in the rate of change of frequency constraints changing from 0.125 Hz/s to 1 Hz/s.[42] As a consequence the system will require less inertia going forward than it has previously as the RoCoF can be higher without causing plants to disconnect. This will be one key contributory factor on allowing the ESO to manage low inertia grids in the future.

It is, however, possible to develop an upper bound cost estimates for addressing some of the key challenges using information on existing technologies and how the system currently operates. One well understood technology that could deliver a number of these services is synchronous condensers; they can be used to provide inertia and reactive power across the system. Assuming that these are the only technologies used to provide reactive power and inertia can give an upper bound on the scale of costs for these services.

As Table 3 sets out, assuming only synchronous condensers are used, and that the system requires a defined level of inertia and reactive power, would cost up to a maximum of around £600 million per year (based on today's cost of the technology). This equates to around one per cent of the total electricity system costs. It would involve deploying approximately 100 condensers all over the electricity network. These figures are based on the rollout of synchronous condensers of the same size as Uniper's in the National Grid ESO Stability Pathfinder Phase 1. This technology can also meet short circuit level requirements although the spatial nature of this system requirement would need to be accounted for.

Table 3: Estimating an upper bound on costs of providing inertia and reactive power[43]

<table>
<tr><th colspan="2">Costs of providing inertia</th><th></th><th colspan="2">Costs of providing reactive power</th></tr>
<tr><td>Assumed inertia required</td><td>100 GVA.s</td><td></td><td>Assumed reactive power required</td><td>5,409 absorption and 10,162 injection</td></tr>
<tr><td>£/MAV.s/year from synchronous condensers</td><td>3,339</td><td></td><td>£/MVAR/year</td><td>57,728</td></tr>
<tr><td>Total annual costs £million per year</td><td>334</td><td></td><td>Total annual costs £million per year</td><td>587</td></tr>
<tr><td colspan="5">Assuming that the needed level of reactive power and inertia and is provided from synchronous condensers, then the maximum is these costs estimates should be taken as the cost of providing both</td></tr>
<tr><td colspan="2">Costs of providing inertia and reactive power from synchronous condensers</td><td colspan="3">£587 million per year</td></tr>
<tr><td colspan="2">Percentage of estimated 2050 total electricity system costs required to provide inertia and reactive power from synchronous condensers</td><td colspan="3">1.5 per cent</td></tr>
</table>

This will likely be a significant overestimate of costs as the optimal mix of technologies able to provide these services will surely involve other technologies beyond synchronous condensers and is likely to be much cheaper.

Additionally, the future cost of system restoration is uncertain. Whilst system restoration has traditionally relied on fossil fuel generators, this is changing as the ESO seeks to support deployment of the most efficient solution to the issue. As set out in Table 2 there are a range of technologies that can be deployed to provide system restoration services in a highly renewable system. The ESO is currently undertaking the Distributed ReStart project which aims to develop a process by which system restoration can be achieved without relying on fossil generation and instead utilising assets such as wind turbines, biomass generators, and embedded hydro power stations.[44] One of the ESO's aims of the project is to increase competition in the supply of system restoration services and drive down costs. It is therefore unlikely that system restoration costs will differ in order of magnitude from where they are today.[45]

These calculations show that meeting operability challenges is not expected to be significant compared to the cost of the overall system. The primary challenge is therefore ensuring the right generation capacity is deployed. this will have far more influence on the overall system costs and ultimately the bill consumers pay.

International evidence[46]

The UK is not alone in moving to a highly renewable electricity system. The significant reductions in the cost of renewables, along with the imperative to decarbonise, has led to many countries setting ambitions for high levels of renewable deployment by 2030. For example, Denmark is aiming for 100 per cent renewable generation by 2030, and Ireland and Spain are aiming for 70 per cent renewable generation by the same date.

It's clear that other regions are therefore confident that they will be able to operate such electricity systems. But different regions will face different operability challenges, so these are not always directly comparable to the GB system. For example, highly interconnected electricity systems – such as Germany or California – can draw on a larger pool of plants to provide inertia and so tend to have more stable systems. But there are examples of electricity systems similar to GB also setting these ambitious targets. For example, Ireland, which operates a minimally interconnected island electricity system has set targets to be able to run its electricity grid on 75 per cent non synchronous generation by 2020.[47]

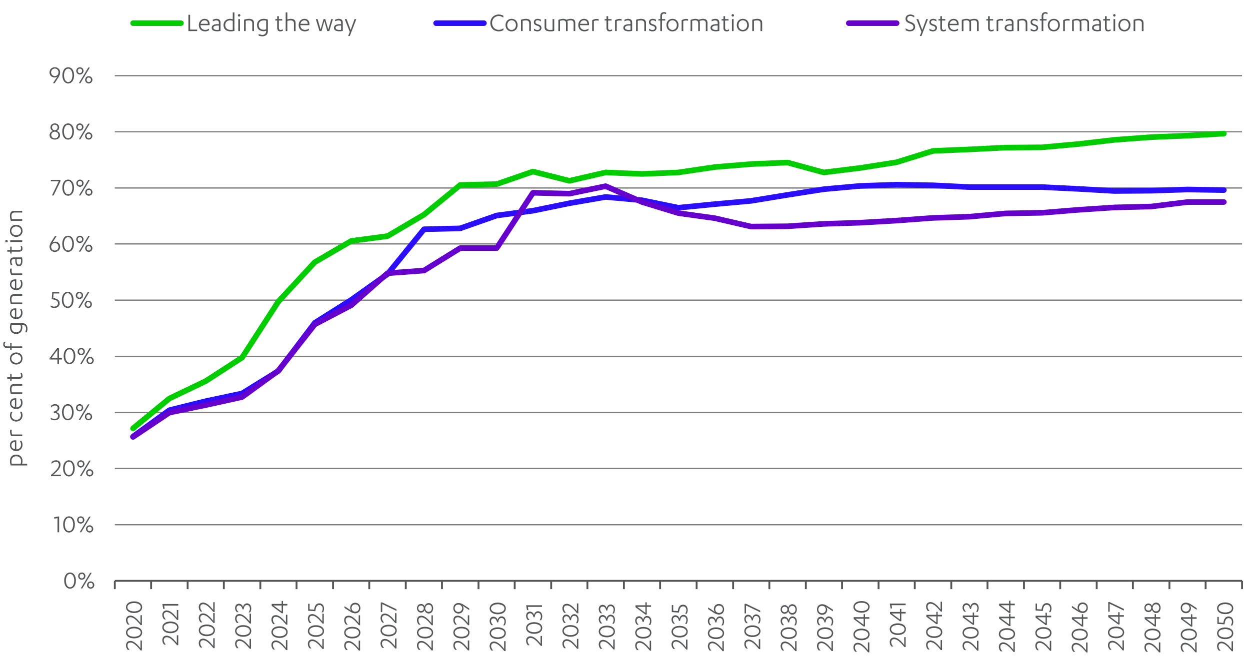
Box 3: ESO Future Energy Scenarios (FES)/2025

The ESO has committed to being able to run a zero carbon grid by 2025, signalling the its confidence that it can run the electricity system with high levels of variable renewables.

Fulfilling this commitment will involve running an electricity system with significantly less synchronous generation than the system has run on before. And whilst it's not clear how long the ESO is aiming to be able to run such a system for – an hour, day, week, or year – it will regardless be a significantly different system from the one we've seen to date.

In addition, in its latest future energy scenarios the ESO published three scenarios for the power sector which are consistent with the UK's net zero target. In these scenarios' renewable penetration ranges from 60 to 70 per cent in 2030 and 70 to 80 per cent in 2050.

Figure 6: Proportion of total generation from onshore wind, offshore wind, and solar in FES 2020 scenarios[48]



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