Net zero power without breaking the bank

Cutting the cost of decarbonising electricity in Great Britain

July 2021

Foreword

> *With the five steps outlined the GB power system could save almost £50bn by 2050, and over £75bn looking out to 2060.*

Alistair Phillips-Davies
CEO, SSE

The UK power sector has delivered significant emissions reductions in the last decade, reducing its emissions by 68% since 2010.

At SSE we are extremely proud to have played our part in that, drastically reducing our own emissions while delivering major investment in the country's low-carbon infrastructure.

In the run-up to COP26, the UK can showcase its leadership on power sector decarbonisation, demonstrating how renewable energy can be deployed at scale and at pace. In doing so, it can help spur the transition away from coal that is so urgently needed if we are to keep global average temperature changes to within 1.5°C of pre-industrial levels.

The UK's large-scale deployment of renewable energy and switching away from coal, driven by effective long-term policy mechanisms and robust carbon pricing, has proved extremely successful in driving rapid emissions reduction in the GB electricity system. However, the last 10-30% of emissions will be more difficult to tackle. We will need to bring forward a range of new technologies, products and services to ensure we have reliable low-carbon energy when the sun is not shining and the wind is not blowing.

Electricity is an essential service and we've seen in the past that keeping a grip on its affordability is critical if a public mandate for decarbonisation is to be maintained. As the 'low-hanging fruit' disappears and decarbonisation becomes more challenging, it is therefore vital that we find the most cost-effective pathway to net zero to minimise the cost to consumers.

We have commissioned this analysis from LCP in order to do exactly that. We hope it will help inform the next stage of the UK's journey to net zero emissions, by identifying clear actions that could drastically cut the cost of net zero electricity – which will be invaluable in helping to decarbonise the wider economy.

As this analysis outlines, net zero power needn't break the bank, and with the five steps outlined GB electricity consumers could save almost £50bn by 2050, and over £75bn looking out to 2060.

It shows that there is a clear path for the UK to take: offshore wind will be at the centre of the GB energy system, supported by progressively decarbonised gas-fired generation in the form of carbon capture and storage (CCS) and hydrogen. Onshore wind and solar, too, have important roles to play, as does consumer flexibility alongside batteries, hydro pumped storage and hydrogen storage to ensure we can maximise the use of the UK's significant renewable energy potential. It's clear that this is the balance of technologies that can deliver net zero at lowest cost.

To deliver on this vision we need to ensure that the right policy and regulatory frameworks are in place and provide effective signals to support early, strategic deployment of enabling energy infrastructure. Critically, a net zero power system requires a net zero electricity market design, and this report shows this is where the greatest savings are to be had, with a £20bn cost reduction by 2050 compared with maintaining current arrangements.

Over the 2020s, the electricity sector can lead a green recovery that generates socio-economic benefits spread across the UK and provides the means by which to decarbonise the wider economy. As this report clearly shows, plotting the right pathway to net zero can deliver many benefits. It will deliver benefits today in the form of green jobs, clean industries and revitalised communities. But it will also safeguard the interests of future consumers – those who will have to pay for the decisions we make today and will ultimately be faced with the greatest impacts of climate change if we fail to achieve net zero quickly enough.

I sincerely hope that this analysis proves useful to policymakers and other stakeholders as we collectively seek to address the climate crisis.

Foreword

Tom Porter
Partner & Strategy Director, LCP

Achieving net zero is one of the biggest challenges facing the power sector, the UK economy and the planet. The decisions taken today will impact both how we decarbonise and at what cost.

LCP has a long history of providing detailed energy market modelling. Our work allows decision makers to see what impact changes to policy and regulation will have and at what cost.

As such, we were delighted to be commissioned by SSE, as part of their COP26 sponsorship, to assess low cost pathways to a net zero power system.

As we decarbonise the power sector, we allow other sectors to switch from using fossil fuels to clean electricity, thereby reducing carbon emissions across the economy. The cost of delivering a net zero power system is not insignificant, but there are technologies and policy decisions that can offer considerably lower costs relative to the current trajectory.

This analysis outlines five clear steps on a low cost pathway to net zero. It shows that a pathway that puts renewables at the centre of the power system need not "break the bank". In fact, our analysis shows that a system centred on offshore wind, complemented by flexible low-carbon thermal generation, long duration storage and green hydrogen production can provide almost £50bn of savings by 2050.

It's no surprise that capital expenditure is the most significant cost in delivering a net zero power system. Ensuring that large amounts of low carbon generation can be deployed at a low cost of capital needs to continue. This will become even more important in the future as the effects of price cannibalisation start to significantly impact the revenue that renewable projects earn after their support contracts end, with wholesale power prices likely to become very low in periods of high wind generation.

Evolving current mechanisms to value all low carbon generation equally (including existing and refurbishing assets) will ensure that the market is fit for purpose in a net zero power system and should be a priority. These reforms have the most significant impact on costs in our analysis, providing almost £20bn of savings by 2050.

With offshore wind set to become the dominant source of generation in GB by the end of the decade, unlocking its potential through a co-ordinated offshore transmission network will be key. Acting now to build a suitable network will ensure that a renewables-centered system can be delivered while costs are kept to a minimum.

With significant work to be done over the next decade to achieve net zero, I hope that the analysis presented in this report will prove valuable to decision makers in the fight against climate change.

The cost of delivering a net zero power system is not insignificant, but there are technologies and policy decisions that can offer considerably lower costs relative to the current trajectory.

Executive summary

The need to reach net zero emissions by 2050 is driving a transformation of the GB energy system.

The UK was the first major economy to commit to net zero emissions by 2050, and the UK Government has also set into law the Climate Change Committee's (CCC) recommendation to reduce emissions in 2035 by 78% compared to 1990 levels inline with the sixth Carbon Budget.

There are multiple possible pathways to achieving these ambitious targets through the deployment of different technologies and policies. As a principal partner to the UK Government on COP26, where the UK will need to demonstrate leadership in the transition to net zero, SSE commissioned LCP to assess the low cost options to delivering a net zero compliant power system.

The analysis uses a whole system cost approach, utilising LCP's EnVision model. The analysis shows that a renewables centred energy system supported by decarbonised gases and long duration storage can reach net zero faster and achieve system cost savings of over £48bn between now and 2050, relative to the current trajectory envisaged, with a further £28bn of benefits accrued through to 2060 to reach £76bn in total.

Key highlights from the analysis

Five steps

to a low cost high renewable system

£48bn

in total system savings through to 2050, and £76bn through to 2060

7.5mtCO2e

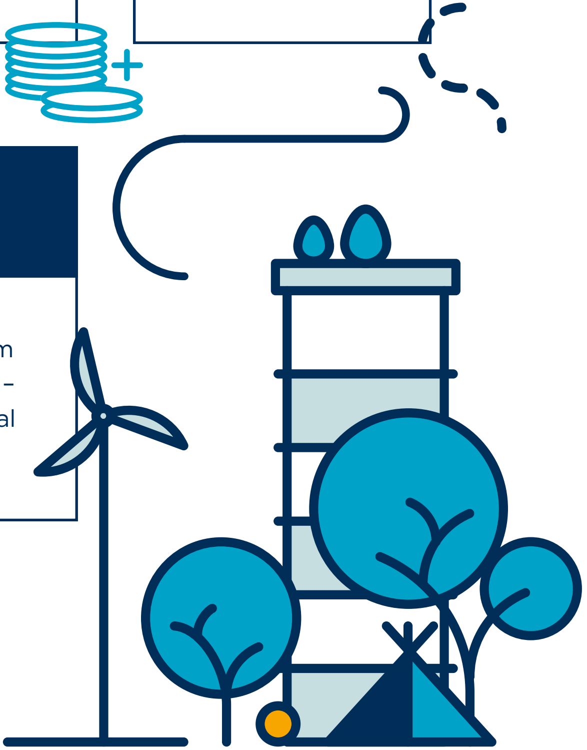
additional carbon savings by 2035, and 19.8mtCO2e by 2050

Equal value

Electricity market design should value all low-carbon generation equally

CapEx

is the most significant system cost component – minimising capital costs will be key



Executive summary *(cont'd)*

Our analysis focused on five key steps to achieve these savings, showing that:

1 **A renewables-led energy system centred on offshore wind** achieves significant system cost savings versus more conventional pathways where greater levels of new nuclear capacity are deployed **See page 12**

2 **Low-carbon thermal generation such as gas Carbon Capture and Storage (CCS) and hydrogen power generation complement renewables** and provide further system cost benefits, while also having wider benefits such as supporting CCS and hydrogen infrastructure in industrial clusters **See page 13**

3 **Longer duration storage and green hydrogen production** are key to balancing a renewables-led system, and the early strategic development of storage options maximise these benefits, though will require support mechanisms to bring these benefits forward **See page 15**

4 **Valuing all low-carbon generation equally** through electricity market reform could save the system £20bn by supporting more economic life extensions, refurbishments or repowering over new assets, the largest single component of the £48bn total savings **See page 17**

5 **A co-ordinated offshore transmission network** can significantly reduce the network costs associated with a high renewable system **See page 19**

Importantly, **capital costs** represent the largest component of costs to meet net zero – getting the right CapEx, at the right times, in the right places and at low cost of financing is key to the lowest cost delivery of net zero.

Our analysis also shows that the GB power system can reach a gross carbon intensity of 25gCO_2e/kWh by 2035 and do so cost effectively. A net negative power sector from the 2030s will support decarbonisation across the economy and be the engine of the UK's efforts to get to net zero. However, policy decisions about when the GB power system becomes net negative as well as to the role of existing gas generation capacity will need consideration to ensure value for money for consumers.

This report summarises the analysis conducted, covering the objectives and principles of the analysis, the "Current Trajectory" scenario used as starting point, and each of the five steps needed to achieve a low cost, high renewables power system.

Introduction

To meet the net zero challenge it is expected that the power sector will aid the decarbonisation of both heat and transport leading to a significant increase in electricity demand over the next thirty years.

Under conventional net zero pathways the addition of new nuclear build is often utilised to provide baseload zero carbon power to meet this increased demand.

In this report an alternative pathway to net zero is presented in which a combination of increased renewable, storage and low-carbon thermal capacity is used instead. This predominantly replaces new nuclear capacity which requires greater levels of investment and thus offers a lower cost alternative.

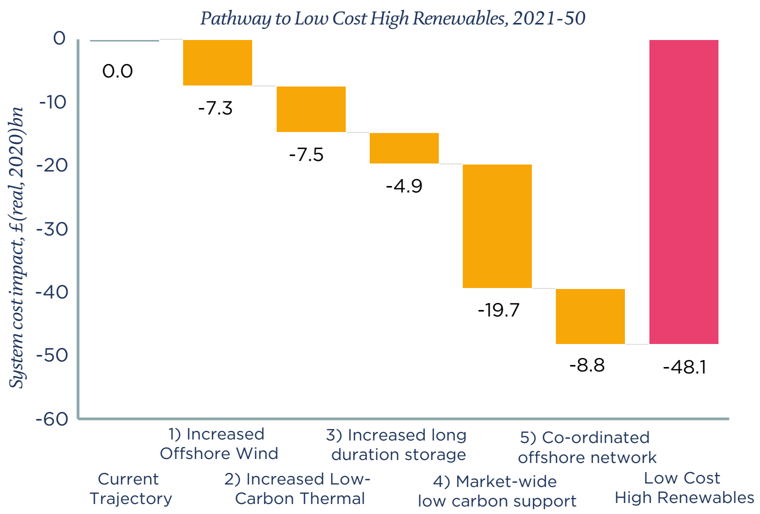
The whole system cost framework[1] developed by LCP, Frontier Economics and the UK Department for Energy and Climate Change (DECC) in 2015 is used to compare the two scenarios. Under this framework the total cost of building, operating and maintaining the GB power system is calculated. This provides a robust methodology for comparing the system costs incurred by each net zero pathway.

The transition from the current trajectory to a lower cost high renewable pathway is made in five steps:

- In **steps one and two** it is assumed there is no new nuclear build post Hinkley Point C, instead additional offshore wind, gas CCS and hydrogen peaking plant are used to meet the capacity requirement.
- In **step three** additional long duration storage, in the form of electrolysers coupled with salt cavern hydrogen storage and hydro pumped storage capacity, is introduced to complement the growth in lithium-ion batteries.
- In **step four** market reforms are made to the low-carbon support regime so that capacity reaching the end of Renewables Obligation (RO) or Contracts for Difference (CfD) support is eligible for support, as are life extensions, refurbishments and repowering. Support for existing assets avoids premature closure and reduces the requirement for new capacity.
- In **step five** the benefit of a co-ordinated offshore transmission network, utilised to connect offshore wind farms to the grid in a cost-efficient manner, is included.

These steps result in a system cost benefit of just over £48bn up to 2050.

Figure 1: Low cost net zero pathway



System costs are presented in terms of Net Present Value (NPV) assessed across 2021-50, with a 3.5% discount rate applied. This discount rate is consistent with the social discount rate used by BEIS.

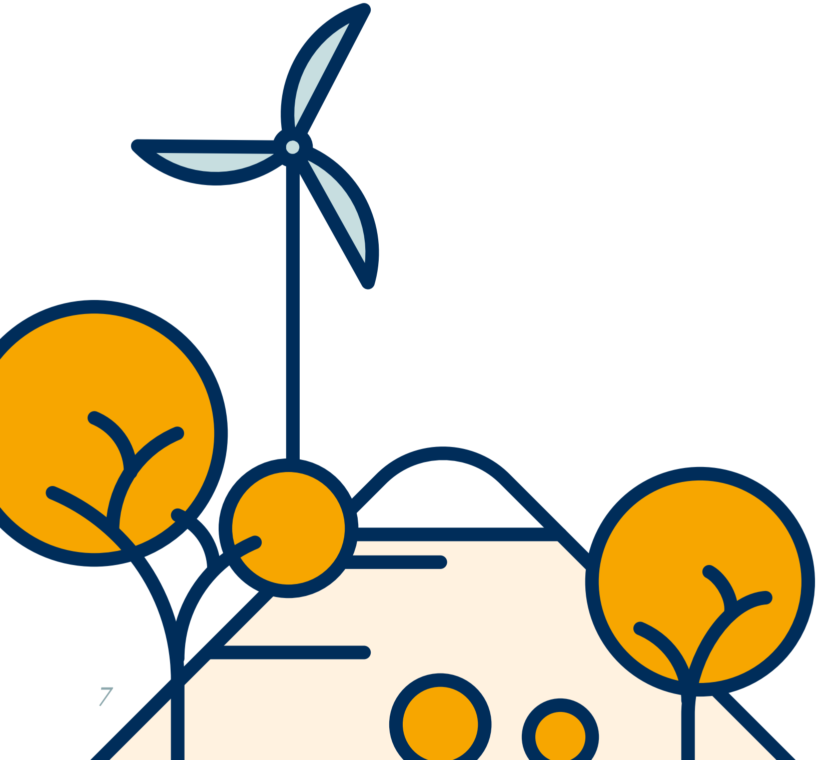
[1] See appendix

Introduction (cont'd)

Key principles of this analysis

For this analysis we started with a scenario that represents one possible trajectory to net zero for the GB power system ("Current Trajectory"). We have then looked at further steps that could be taken, through changes to policy, electricity market design and network regulation, to maximise the potential of GB renewables and minimise overall costs.

For each of the steps, the resulting new scenario was required to satisfy a number of key principles which are outlined opposite.



Net zero

- Scenarios are consistent with a pathway to net zero by 2050, where decarbonisation of the GB economy is driven by the power sector (heat & transport)
- The gross carbon intensity of GB power system approaches near zero in the 2030s

Low cost

- Objective is to reduce costs over the period to 2050
- "Cost" is defined as GB power system costs, consistent with existing BEIS framework

Deliverable and achievable

- Proven, mature generation technologies are central
- Credible assumptions for build rates and technology cost reductions

Scenarios are evaluated on a consistent basis

- Decarbonisation trajectory consistent with interim carbon budgets to 2050, and is kept consistent across scenarios
- Analysis determines a technology mix and policy framework that achieves this trajectory at low cost

Keeping the lights on

- Maintain the same security standard across all scenarios, based on GB's current Loss of Load Expectation (LOLE) standard of 3 hours per annum

The current trajectory

In this analysis the impact of low-cost alternatives is assessed against an envisaged "current trajectory" that is net zero compliant.

This scenario represents a potential pathway to net zero power that could result without further steps being taken to maximise the potential of GB renewables. The scenario has been developed by LCP with input from SSE, with many of the key assumptions informed by the scenarios published by National Grid ESO's FES 2020 and BEIS.

Figure 2: Projected installed capacity mix under the Current Trajectory scenario

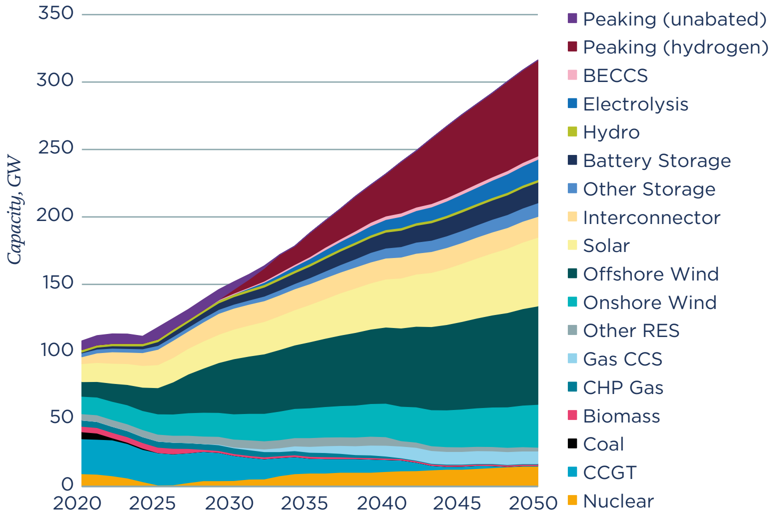
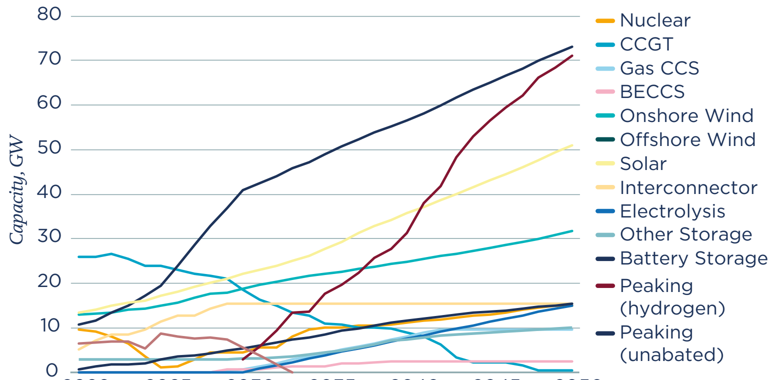


Figure 3: Projected installed capacity for selected technologies under the Current Trajectory scenario

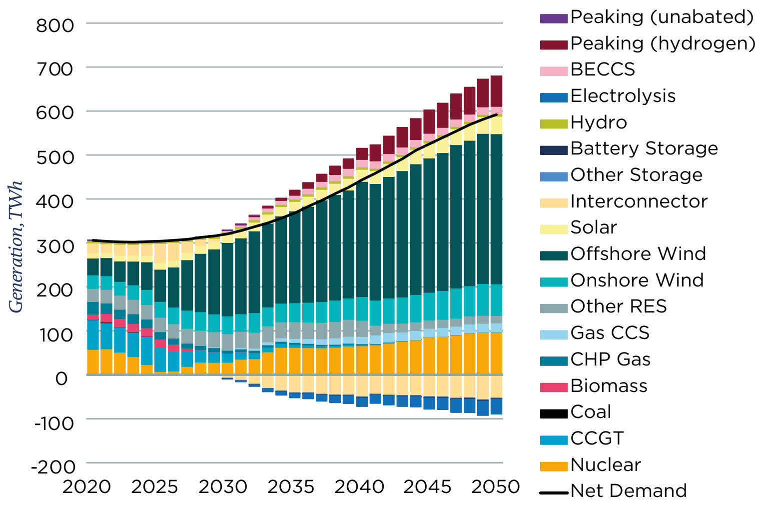


In this scenario nuclear capacity reaches 15GW by 2050 with offshore wind reaching 73GW (after meeting the 2030 target of 40GW), onshore wind 32GW and solar 51GW. Dispatchable generation provides support with 10GW of gas CCS and 71GW of low-carbon peaking capacity installed by 2050. Storage in the form of battery, pumped storage and hydrogen production and storage (electrolysis) capacity totals 40GW.

New build gas peaking capacity installed from 2030 is assumed to be hydrogen ready, requiring little change to re-configure or upgrade to run on low-carbon hydrogen.

It is assumed that Bioenergy with carbon capture and storage (BECCS) is brought onstream during the 2030s. The four Drax biomass units are assumed to convert following the end of the support received from the RO scheme in 2027 with a conservative assumption used for the first converted unit coming online in 2030.

Figure 4: Projected generation mix under the Current Trajectory scenario

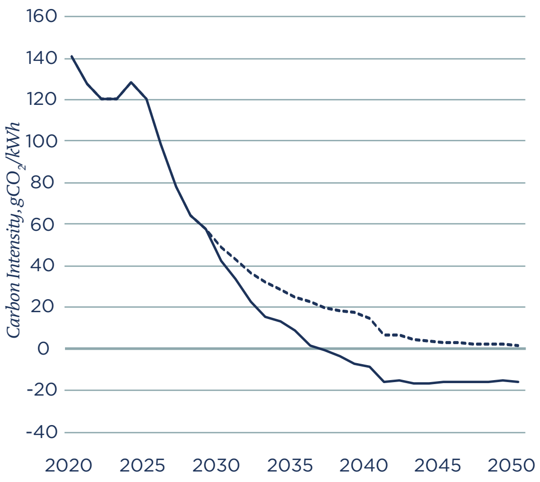


Demand is assumed to be relatively stable through the 2020s after which there is significant growth due to the decarbonisation of heat and transport. We assume transport is predominantly decarbonised through electrification, while heating is mostly decarbonised through hydrogen with some electrification. This is broadly consistent with BEIS's "low demand" net zero scenario.

By 2050 offshore wind provides 56% of total demand generating 331TWh, nuclear provides a further 98TWh, onshore wind 68TWh and solar 41TWh. The UK becomes a net exporter of clean energy with exports reaching 50TWh in 2050.

The current trajectory (cont'd)

Figure 5: Projected Electricity Carbon Intensity under the Current Trajectory scenario

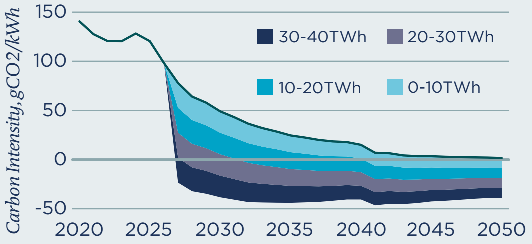


A gross carbon intensity in the power sector of very close to zero (less than $2gCO_2e/kWh$) is reached by 2050. If BECCS is treated as providing negative emissions, with the biomass production serving as a carbon sink, the carbon intensity reaches zero by 2036 and is negative ($-16gCO_2e/kWh$) in 2050.

A net zero power system?

What exactly it means for the power system to be clean, zero carbon or decarbonised is not clearly defined in the wider stakeholder debate, with most analyses focusing on "net zero" without stating this explicitly. In this analysis, we have taken a separate view on gross and net emissions intensities to be clear on both. We have assumed that the gross carbon intensity (total carbon emissions excluding any negative emissions) reaches a value very close to zero in 2050, but residual emissions from gas CCS means that absolute zero emissions are not achieved, even beyond 2050. However, once negative emissions from BECCS are included, the power sector delivers net negative throughout the 2040s.

Figure 6: Impact on GB power sector net emissions from different levels of BECCS deployment

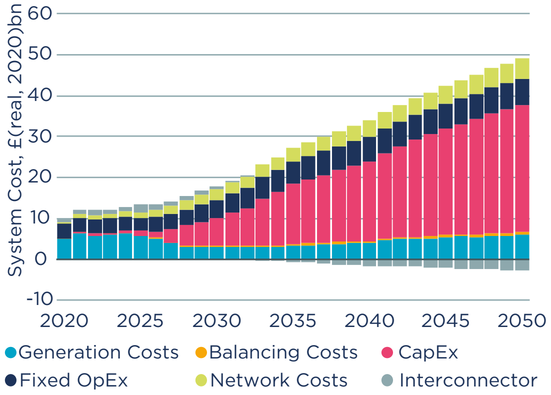


Negative emissions provided by the power sector in the form of post combustion CCS on a biomass power station (or biogenic content in Energy from Waste plant) or pre-combustion CCS of biomass for use as hydrogen can offset emissions in other harder to decarbonise sectors of the economy, and allow for the economy as a whole to achieve "net zero" emissions.

In this analysis, the role of BECCS and the mechanisms under which it is supported is not the main focus. We have assumed a BECCS buildout consistent with Ricardo's low scenario[2] and assumed that BECCS will be incentivised to run baseload through high carbon prices that value its negative emissions. We do not vary its buildout or operating profiles in our scenarios.

In both scenarios, the GB power sector becomes net negative by 2036, but exactly when the GB power system crosses $0gCO_2/kWh$ will be a choice for policymakers as it will come at an additional cost. Technically the GB power system could become net negative from 2027 with significant volumes of BECCS – it just might not be cost effective compared with other carbon savings elsewhere in the economy or the best use of a limited bioresource.

Figure 7: Projected System Costs under the Current Trajectory



Capital costs (CapEx) costs form the largest component of system costs incurred with around £220bn of new investment required between now and 2050. A financing cost of CapEx approach is used whereby CapEx incurred is spread across the lifetime of a plant. Note that only CapEx costs stemming from new build are included in this analysis.

Fixed Operating Expenses (OpEx) and Network costs form the next largest components of system costs, these increase over time due to the increase in low-carbon and renewable capacity required to meet demand in this scenario.

From this current trajectory, we identified five key steps that should be taken to achieve a low cost high renewable system. Below we provide detail on each of the five steps.

[2] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/911268/potential-of-bioenergy-with-carbon-capture.pdf

Step 1

Go big on offshore wind

+ £7.3bn system benefit, NPV (2021-50, 3.5%)
+ £270 system cost saving per household
+ Increase offshore wind from 73GW to 93GW

As a first step on the path to a low cost, high renewable system we add additional renewable capacity, replacing capital intensive nuclear capacity.

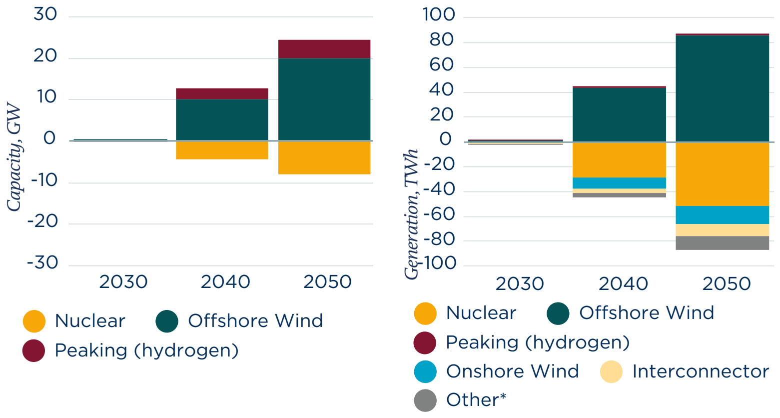
Offshore wind capacity is increased by 20GW relative to the current trajectory by 2050 which requires a total build-out rate for offshore wind of 3GW per annum. This represents an ambitious, but still achievable level of build-out. The low-carbon generation provided by this additional offshore wind capacity acts to replace 8GW of nuclear capacity. Due to the faster build time of offshore wind, it also allows a faster rate of decarbonisation through to 2035, once further steps to maximise the potential of renewables are taken.

To ensure capacity adequacy, additional backup peaking capacity is introduced (around 4GW of low-carbon gas peaking capacity, utilising low-carbon hydrogen). This ensures that an equivalent amount of firm capacity is being added to account for the the nuclear capacity being displaced.

Offshore wind capacity, GW			
	2030	2040	2050
Current Trajectory	40	56	73
Step 1: Go big on offshore wind	41	67	93
Note: Further changes to offshore wind capacity are made in subsequent steps			

*Note: In this chart 'Other' refers to all remaining technologies, including decreased solar generation and increased green hydrogen production using electrolysis (shown as a decrease in generation).

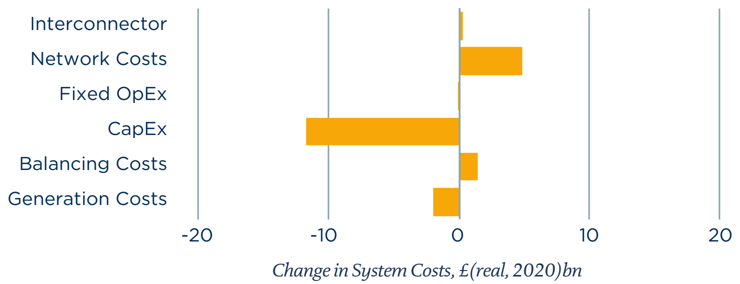
Figure 8: Change in capacity and generation due to increased offshore wind



The additional offshore wind generation primarily displaces nuclear generation, but also increases net interconnector exports. By 2050 an additional 10TWh of electricity is exported per annum. The 'other' is generation displacement including onshore wind (curtailed at the expense of offshore wind generation) and greater use of electrolysers.

Overall there is a system cost benefit of **£7.3bn** (NPV 2021-50, 3.5% social discount rate) between 2021 and 2050. The majority of this saving is due to reduction in CapEx costs; offshore wind is much less CapEx intensive than nuclear with a cost of £1,600/kW in 2030 for new offshore wind versus almost £4,800/kW for nuclear assumed in this analysis. Even allowing for the lower load factors of offshore wind, and the additional backup capacity required due to the low level of firm capacity provided by each marginal unit of installed offshore wind capacity, this represents a significant saving. Further cost reductions for offshore wind would clearly increase these benefits.

Figure 9: Change in System Costs due to additional offshore wind



In addition to the CapEx savings, generation costs also decrease due to savings in nuclear variable and fuel costs. These savings are partially offset by the higher balancing and network costs associated with the additional offshore wind capacity.

The analysis does not include floating offshore wind, but further cost reductions could enable lower scenario costs and open up greater availability of offshore wind resource[3].

[3] https://ore.catapult.org.uk/wp-content/uploads/2021/01/FOW-Cost-Reduction-Pathways-to-Subsidy-Free-report-.pdf

Step 2

Add flexible low-carbon thermal generation to support a renewables-led energy system

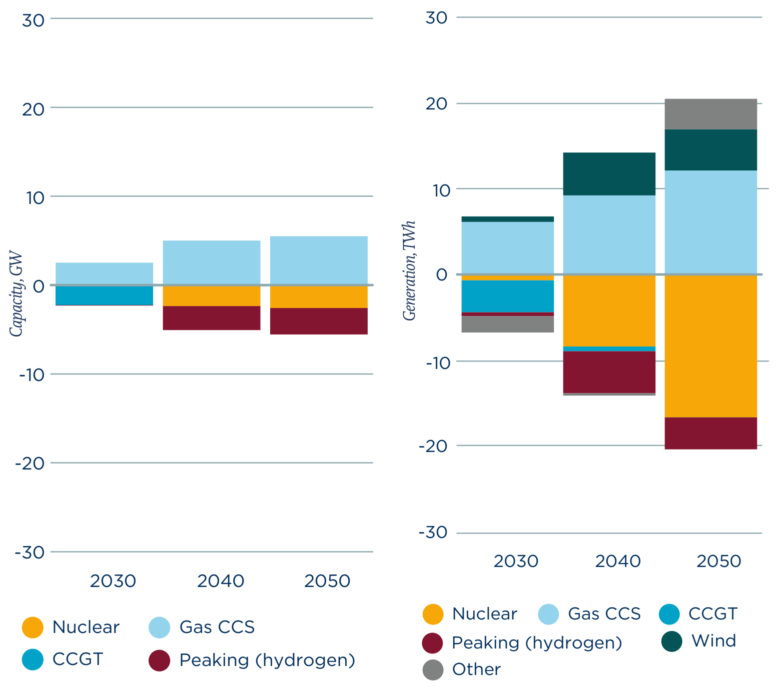
+ £7.5bn benefit, NPV (2021-50, 3.5%)
+ £280 system cost saving per household
+ Supports the deployment of CCS and hydrogen infrastructure within industrial clusters

In the second step, additional low-carbon thermal generation in the form of natural gas plant with CCS is used to provide flexibility to complement the high levels of renewables in this scenario.

This displaces the remaining new nuclear build (not displaced in step one), and also some gas peaking capacity. The additional gas CCS capacity acts both to replace the firm capacity provided by the new nuclear plant and as a source of dispatchable generation to complement the increased renewable build. This low carbon generation is also able to support the decarbonisation of industrial clusters through the shared use of CCS and hydrogen infrastructure.

An additional 5.5GW of gas CCS capacity to the 10GW in the current trajectory scenario is built between 2028 and 2050; this acts to replace 2.6GW of nuclear capacity and displaces a further 3GW of both hydrogen and unabated gas peaking capacity. Earlier CCGT closures arise as CCGT plant are displaced in the overall merit order by gas CCS plant which is less exposed to higher carbon prices. This results in an overall carbon benefit with the reduction in CO_2 emissions from CCGT generation only partially offset by the low emissions from gas CCS plant.

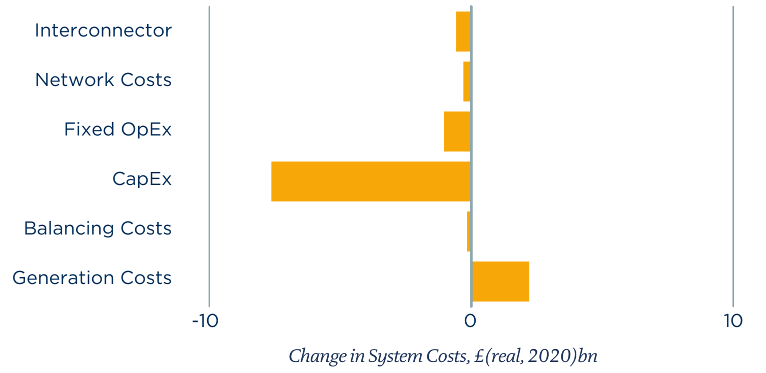
Figure 10: Change in capacity and generation due to increased low-carbon thermal



The addition of this dispatchable gas CCS capacity combined with the removal of baseload nuclear generation reduces the requirement for low carbon peaking capacity. It also unlocks additional wind generation that would otherwise be curtailed to accommodate nuclear generation.

There is a system cost benefit of £7.5bn (NPV 2021-50, 3.5% social discount rate), the majority of which is due to reduced CapEx costs due to gas CCS being less capital intensive than new nuclear plant. This is partially offset by increased generation costs with gas CCS having high fuel costs and a small amount of residual carbon cost.

Figure 11: Change in System Costs due to increased low-carbon thermal



Step 2 (cont'd)

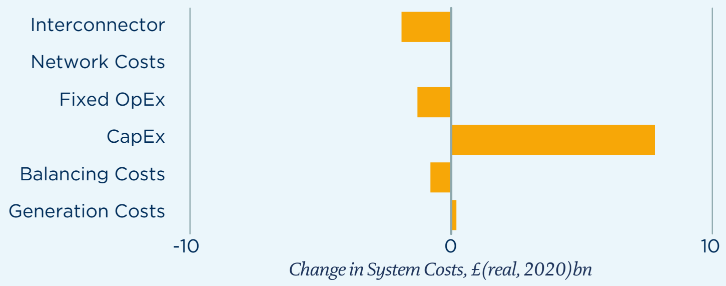
Phasing out unabated gas?

The analysis looked at a further sensitivity where all unabated gas capacity was phased out in 2035. It was assumed that this capacity was replaced by low-carbon thermal capacity, a combination of gas CCS and hydrogen.

In 2035 we project almost 20GW of unabated gas capacity will remain on the system, including 10GW of CCGT.

The early closure of unabated gas and new low-carbon thermal resulted in a reduction in emissions of 22mtCO_2e over the 2035-2050 period, but led to an increase in system costs of £4bn which equates to a cost of abatement of around £180/tCO_2e in discounted terms.

Figure 12: Change in System Costs due to early phase-out of unabated gas capacity

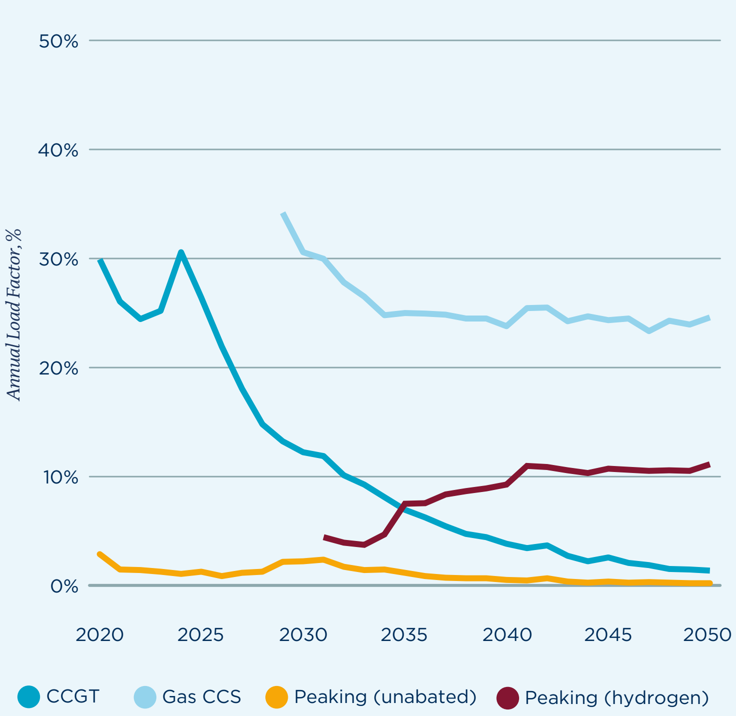


In the current trajectory scenario the load factors of the unabated gas fleet are very low in 2035 (around 8% for CCGT and 2% for peaking plant), and fall further beyond this, with even efficient CCGTs effectively providing backup capacity. This is due to the high assumed carbon price, with gas CCS and hydrogen (low carbon peaking capacity) providing dispatchable generation and running ahead of unabated CCGTs in the merit order.

This analysis suggests that phasing out low load factor plant before the end of their economic life does not present value for money, and CCS retrofit or 100% hydrogen conversion does not appear to be economic compared to building a new generating asset.

However, it is worth noting that emissions savings could be realised cost effectively through reducing the emissions of the existing unabated gas generation fleet when it is required to run to maintain security of supply through blending up to 50% hydrogen, depending upon technical capability of the existing turbine, or by utilising biomethane or synthetic methane.

Figure 13: Annual load factors of gas technologies



Step 3

Deploy long duration storage and green hydrogen

+ £4.9bn system benefit, NPV (2021-50, 3.5%)
+ £180 system cost saving per household
+ Reduction in renewable curtailment of 360TWh

In the third step, additional long duration storage and hydrogen electrolyser capacity are introduced, complementing the high levels of renewable generation.

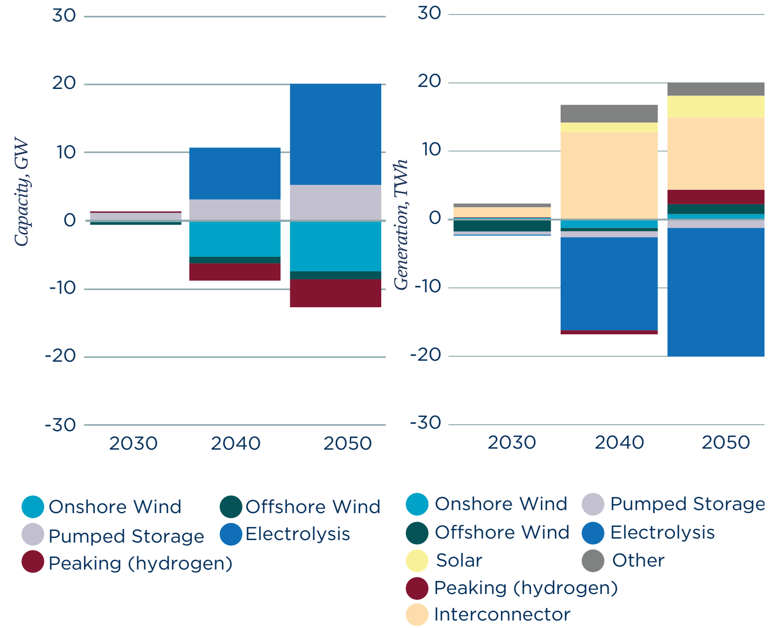
This flexible capacity reduces the amount of renewable capacity required to provide the same level of generation and provides a system cost benefit by reducing both capital costs and balancing costs with lower levels of curtailment.

In this step hydro pumped storage capacity is increased by 5GW in 2050 and electrolyser capacity is increased by 15GW with total hydrogen storage capacity reaching 15TWh. Hydrogen storage is assumed to take the form of salt cavern storage, which is estimated to be around 6 times cheaper than above ground storage[4]. Due to the increases in long-term storage and electrolyser capacity 360TWh of excess renewable generation (over the period through to 2050) being curtailed in the Current Trajectory scenario can instead be stored or converted to green hydrogen that is used elsewhere in the economy.

This reduces the amount of renewable capacity required to achieve the same overall level of decarbonisation, with onshore wind capacity reducing by 7GW, offshore wind by 1GW.

Importantly, the hydrogen storage capacity would also help provide secure supplies of green hydrogen and stabilise prices for industrial users within hydrogen clusters.

Figure 14: Change in capacity and generation due to increased long duration storage



The main changes in the generation mix are an increase in electrolysis demand (negative generation)[5], with an additional 18TWh per annum by 2050, and a decrease in electricity exports (shown as an increase in interconnection generation or net imports). Rather than exporting cheap renewable generation to neighbouring markets, it is used to produce green hydrogen domestically. Renewable capacity is reduced to offset the avoided curtailment, meaning there are only small changes in renewable generation.

There is an overall system cost benefit of £4.9bn (NPV 2021-50, 3.5% social discount rate) these savings are split across reductions in generation, balancing, network and CapEx costs. In addition, residual emissions from the production of blue hydrogen are displaced, reducing overall carbon emissions in the economy.

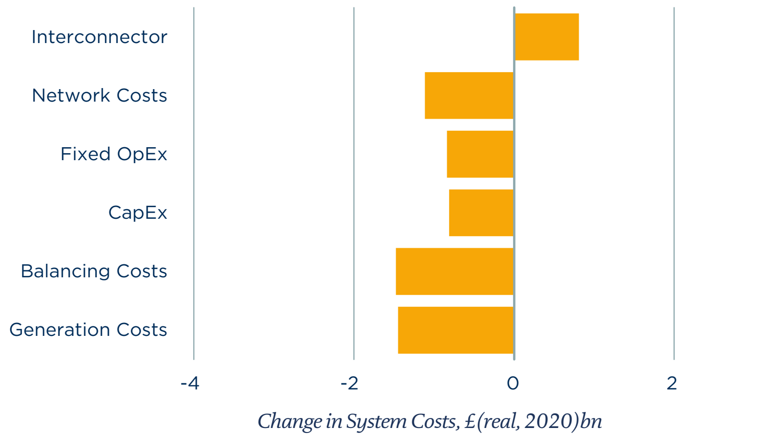
[4] Element Energy (2018) estimates, cited by the CCC https://www.theccc.org.uk/wp-content/uploads/2018/06/Imperial-College-2018-Heat-decarbonisation-modelling.xlsx

[5] Electrolysers are modelled as dispatchable demand, producing hydrogen when electricitiy prices are low. We assume that the price for hydrogen in GB is set by the marginal cost of blue hydrogen production, which is linked to the gas and carbon price. This means electrolysers run when electricity prices are low enough to produce green hydrogen at lower cost than blue hydrogen, assuming there is sufficient hydrogen demand including storage capacity.

Step 3 *(cont'd)*

The flexibility provided by long-duration storage reduces generation and balancing costs, with renewable generation at points of high wind being used to discharge in later high price periods. This reduces the need to utilise higher cost peaking capacity. The decrease in installed onshore and offshore wind leads to a reduction in network costs. CapEx costs also reduce slightly as the incurred cost of additional storage (spread over a longer lifetime) are outweighed by savings from new build peaking capacity that is no longer required. The generation and CapEx cost savings also account for the avoided costs from producing blue hydrogen elsewhere in the economy, offset by the costs of the green hydrogen produced by the additional electrolysers.

Figure 15: Change in system costs due to increased long duration storage



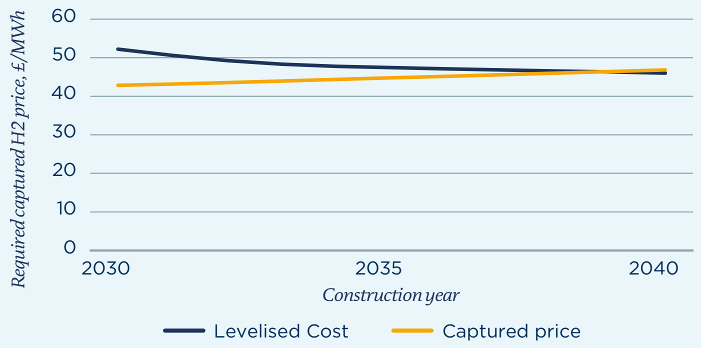
Support mechanisms for long duration storage and green hydrogen?

Demand side flexibility, lithium-ion batteries and long duration storage will be required to decarbonise electricity systems cost effectively. However, long duration storage options like hydro pumped storage and hydrogen storage have steep upfront costs and long lifetimes, meaning current market mechanisms to support new build such as the Capacity Market (CM) and CfD may not provide the correct level and structure of payments to incentivise this additional long duration storage build. These support mechanisms are also designed for different purposes – electrolysis and hydrogen storage do not provide system security (as defined in the CM), and do not directly provide electricity (as the CfD contracts are structured to incentivise).

This analysis shows that long duration storage provides system benefits through the increased utilisation of renewable capacity. However, the assets themselves may not be able to fully monetise these benefits. An example of this is shown on the chart to the right, which compares the levelised cost of green hydrogen production (at a deployment level that is optimal from a system perspective) to the price it would be expected to capture from selling this hydrogen. This positive externality suggests a case for support to allow for early, strategic investment.

Relying on short term market signals alone will not result in an adequate level of long duration storage investment, exposing consumers to higher costs than necessary (https://www.imperial.ac.uk/energy-futures-lab/reports/Whole-System-Value-of-Long-Duration-Energy-Storage-in-a-Net-Zero-Emission-Energy-System-for-Great-Britain/). It may also inhibit the development of hydrogen clusters which would benefit from more stable hydrogen prices. To deliver these system and wider benefits, and reduce the financing costs of these capital intensive assets, new revenue stabilisation mechanisms will be required.

Figure 16: Comparison between levelised cost and captured price for "system optimal" level of green hydrogen production (LCP analysis)



Step 4

Evolve to a complete market for low-carbon generation

- *£19.7bn benefit, NPV (2021-50, 3.5%)*
- *£730 system cost saving per household*
- *87GW of wind capacity extending its economic operation cost effectively*

The current CfD regime only provides support to new low-carbon generation capacity.

Under the fourth step, revenue stability is expanded to cover existing low-carbon generation capacity, including life-extensions, refurbishments and repowering.

Under the current trajectory, large amounts of existing low-carbon capacity reach the end of their CfD or RO support from around 2030 onwards and will close prematurely as they are unable to cover their ongoing costs or the cost of life-extensions or refurbishments. This is due to a combination of low market income, due to low wind-captured power prices, and high ongoing fixed costs.

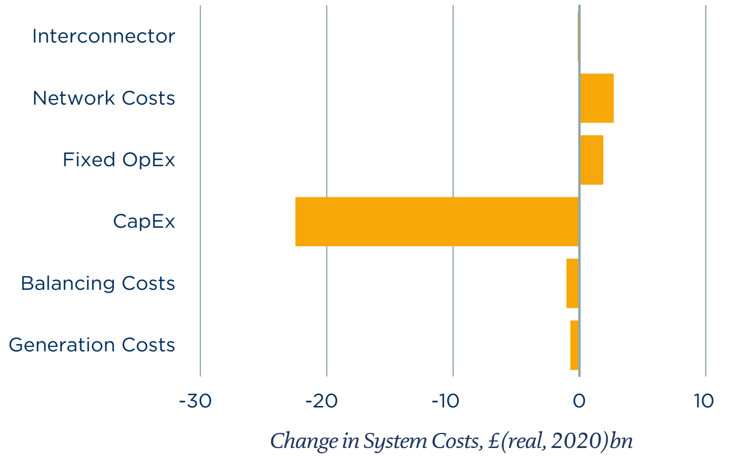
This is a particularly important issue for offshore wind (see simple example in box on the next page), which has high ongoing fixed operating costs and high Transmission Network Use of System (TNUoS) costs due to Offshore Transmission Owner (OFTO) charges. It is also an issue for onshore wind connected in zones with high TNUoS charges – such as Scotland, where a large proportion of existing onshore wind is located, as is a significant portion of the UK's offshore wind resource.

With high levels of renewable penetration, wholesale power prices fall during times of high renewable output, often to as low as zero. This means "wind-captured" power prices fall significantly, and unsupported wind plant may be unable to make sufficient returns to cover their high ongoing fixed costs. In some cases this would imply early closure of plant. Whilst long duration storage in step 3 will make use of available renewable resources it does not address the missing money problems for renewables generation.

Reforms to low-carbon support regimes to value all low carbon power equally, regardless of whether it's from new build or existing plant (in a similar way to the current Capacity Market), could prevent premature closure of existing plant and result in significant system savings from building more expensive new low-carbon plant to maintain the same decarbonisation trajectory.

This is the single largest saving of any of the five steps, with electricity market reform saving the system £19.7bn through to 2050. Most of this saving is in avoided capital costs from avoided new build.

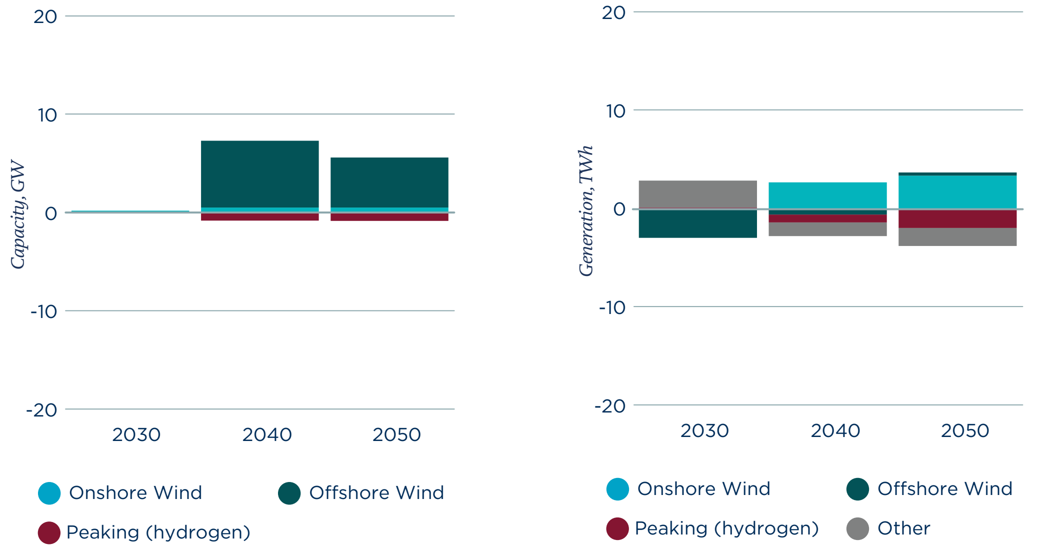
Figure 17: Change in system costs due to market-wide low carbon support reforms



Step 4 (cont'd)

Because the existing wind capacity has lower load factors than the new build, by 2050 there is an additional 5GW of offshore wind and 1GW of onshore wind online under the new scenario. This is because the scenario maintains the same decarbonisation trajectory, so more capacity is required to achieve the same level of renewable generation. This results in additional network and fixed costs that partially offset the large CapEx savings.

Figure 18: Change in capacity and generation due to market-wide low carbon support



Example of the economics of an **existing offshore wind plant** coming off support in the 2030s:

- Annual Load Factor: 35-40% (note that new plant have much higher ALFs)
- Fixed OpEx: £35-45/kW/yr
- TNUoS, incl. OFTO: £50-70/kW/yr (note there is a wide range between locations)
- Variable OpEx: £5-15/kW/yr
- Required market income to cover ongoing costs (ignoring imbalance costs, curtailment and ancillary or capacity market income): £90-130/kW/yr = **£26-42/MWh**

For many plants, our analysis shows wind-captured prices are insufficient to cover this required income in the 2030s.

Step 5

Take a co-ordinated approach to offshore transmission

+ £8.8bn benefit, NPV (2021-50, 3.5%)
+ £325 system cost saving per household
+ Reduced impact on local communities and environment

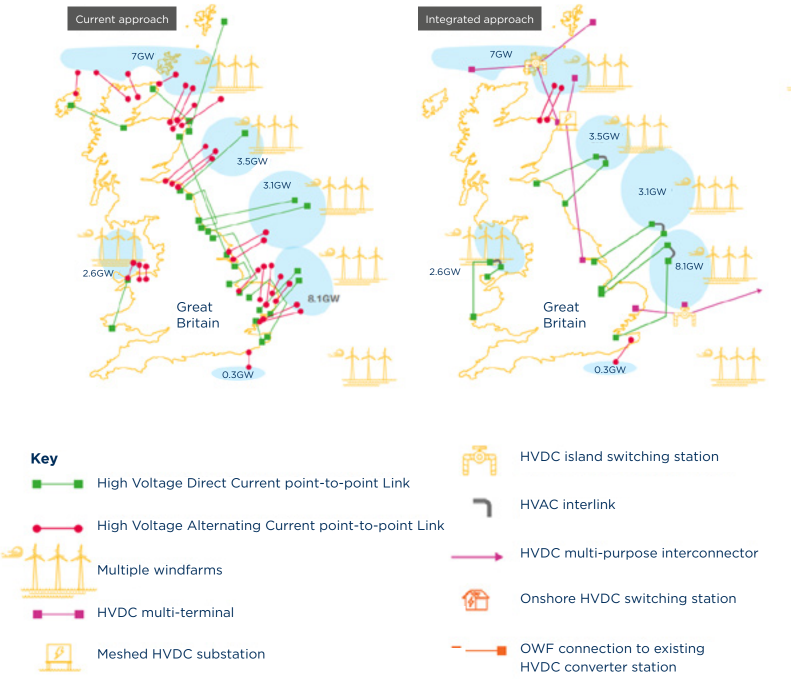
In step five, a co-ordinated offshore transmission network ensures the efficient connection of offshore generation assets to the main grid.

Instead of connecting offshore generation in a piecemeal manner a co-ordinated network would allow:

- Offshore transmission assets to be shared between multiple offshore projects
- An optimised network design to connect multiple generation assets
- Efficiencies in the supply chain and delivery of offshore transmission assets due to standardisation and modularisation of the offshore network design

From the cost benefit analysis in National Grid ESO's Offshore Co-ordination Phase I Final Report[6]: "Adopting an integrated approach for all offshore projects to be delivered from 2025 has the potential to save consumers approximately £6 billion, or 18 per cent, in capital and operating expenditure between now and 2050."

Figure 19: From National Grid ESO: Status quo and Integrated GB network designs in 2030



We assume the same 18% saving in CapEx and OpEx costs for offshore network projects delivered after 2025, but show a higher overall cost saving (£8.8bn) than National Grid ESO. This larger saving is primarily due to higher total offshore wind capacity in our scenario (97GW in 2050) and differences in our network cost projections.

Further network cost savings could be realised through the development of offshore wind hubs, potentially linked to multi-purpose interconnectors. Offshore electrolysis could also play a role in reducing offshore network costs, allow for the greater use of more remote wind resources and provide low cost green hydrogen for nearby industrial clusters, with offshore wind transported back to shore via both electricity and hydrogen[7]. These further benefits are not estimated as part of this analysis.

A coordinated offshore network would also have wider benefits that are not quantified in this analysis, including environmental, social and local impacts through the reduced number of onshore connections points.

[6] https://www.nationalgrideso.com/future-energy/projects/offshore-coordination-project

[7] https://ore.catapult.org.uk/wp-content/uploads/2020/09/Solving-the-Integration-Challenge-ORE-Catapultr.pdf

Conclusions

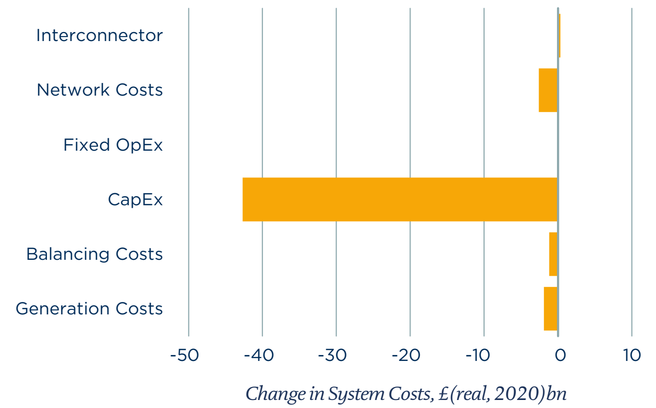
+ *£48bn benefit, NPV (2021-50, 3.5%)*
+ *£1,780 system cost saving per household*
+ *System benefit extends to £76bn if looking out to 2060*

We achieve a net zero power system that is high in renewables and low in cost, maximising the potential of renewables through the use of complementary technologies (low-carbon thermal and long duration storage), policy reform (a market-wide low carbon support regime) and a co-ordinated approach to offshore transmission. The scenario also achieves faster decarbonisation rates over the next 10-15 years, helping the UK in meeting its ambitious 2035 carbon target under the sixth Carbon Budget.

There are also a further £28bn in savings in NPV terms (£76bn in total) if we evaluate through to 2060. Although we assume the system reaches a net zero "equilibrium" in 2050, many of the benefits of the investments are accrued after 2050 due to the long financing periods for new assets.

The energy system decarbonises faster with an additional 7.5mtCO_2e saved ahead of 2035. Overall, carbon emissions are reduced by 0.6mtCO_2e per annum on average between 2021 and 2050. Long duration storage and hydrogen production, generation and storage are key to enabling these reductions in emissions and maximising the utlisation of renewable capacity.

Figure 20: Change in system costs from Current Trajectory to Low Cost High Renewable



Any forecasts through to 2050 are subject to significant uncertainty. However, given the magnitude of the system benefits presented, we believe the overall conclusions presented in this analysis are robust. Where possible we have relied on widely respected published sources for our assumptions, and have kept proven, mature technologies central to our future capacity mixes to ensure the scenarios remain credible.

Conclusions

There are several key conclusions from this analysis:

Most of the costs on the pathway to net zero power are capital costs given the high upfront costs of the infrastructure required. Maintaining a low cost of capital, and deploying the right capital at the right times and in the right places will be key

- Further reform to the electricity market is required, with a complete market for low-carbon energy that isn't limited to new build
- Strategic investment is needed to accelerate development, make best use of spatial constraints and lower costs (e.g. co-ordinated offshore transmission). This includes support for strategic deployment of long duration storage

Heavier on renewables, can be lighter on costs and quicker on carbon

- Our analysis shows a high renewables system saves money relative to a system with high levels of nuclear build-out
- A high renewables system can also achieve a faster rate of decarbonisation, due to the faster build time of renewables relative to nuclear, saving an additional 7.5mtCO_2 by 2035

Dispatchable gas CCS and hydrogen power generation complement renewables

- They also present wider benefits, supporting infrastructure in clean industrial clusters

Long-duration storage and green hydrogen production provide further benefits and are key to balancing a renewables-heavy system, but needs early, strategic deployment to maximise system value

- Can reduce curtailment and allow lower renewable capacity for the same levels of decarbonisation
- Green hydrogen combined with hydrogen storage can offset costs and emissions elsewhere in the economy (in producing blue hydrogen) while maximising the utilisation of renewable generation assets

Valuing all low-carbon generation equally through reforming low-carbon support regimes to include existing capacity could save £19.7bn through to 2050 or £730 per household

- Preventing premature closure of existing assets and supporting life extensions and repowering are critical to meeting net zero cost effectively

Investing now will reap dividends from 2030, but also ensure long-term benefits beyond 2050

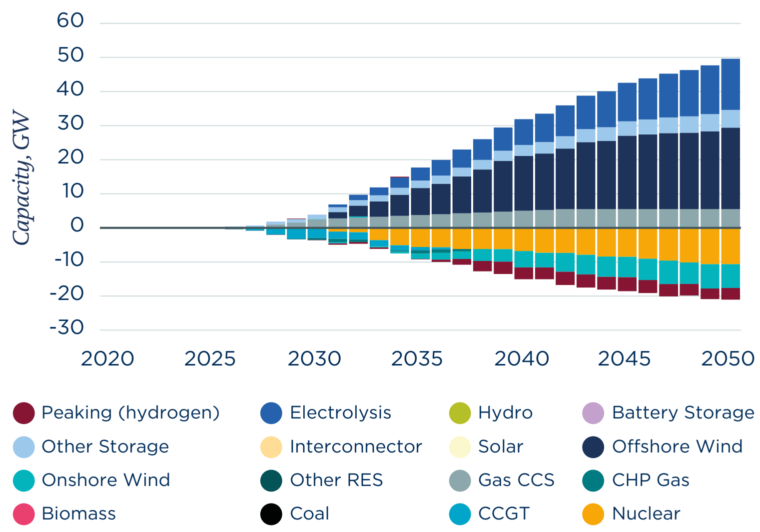
- These steps provide a further £28bn of estimated benefits, in addition to the £48bn between 2021-50, over the decade through to 2060 helping to reduce intergenerational inequality

A low cost high renewable power system - summary

Overall results

The following charts summarise the total changes in capacity, generation and system cost between the Current Trajectory and Low Cost High Renewable scenarios on an annual basis. This combines the effects of the five individual steps.

Figure 21: Change in capacity from Current Trajectory to Low Cost High Renewable



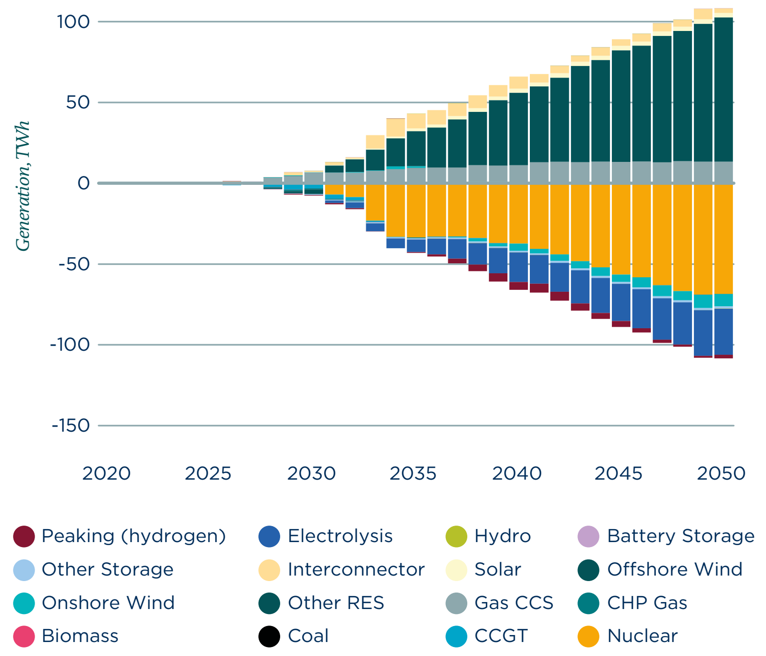
Capacity mix

The main changes in the **capacity mix** are:

- Increase in offshore wind capacity, with the 2050 capacity increasing from 73GW to 97GW.
- Additional 5.5GW of gas CCS capacity. The combination of flexible gas CCS and low-carbon hydrogen generation complements the additional renewable capacity, reducing the need for baseload nuclear capacity.
- Additional 5GW of hydro pump storage capacity and 15GW of electrolyser capacity giving a total of 7.5TWh hydrogen storage capacity. This long-term storage helps to balance the system, increasing the utilisation of renewable generation, as well as provide secure supplies of green hydrogen within industrial clusters, at stable prices.
- Reduction in new nuclear capacity by almost 11GW, with no new nuclear capacity included beyond 2030. Due to the high capital and fixed costs associated with new nuclear, this provides a significant system benefit.
- Reduction in low-carbon gas peaking capacity by around 5GW, with the additional pumped storage and gas CCS alongside less inflexible nuclear reduces the need for low-load factor backup gas capacity.
- Reduction in CCGT capacity in the late 2020s and early 2030s, existing plants retire earlier and are displaced by low-carbon gas CCS.

A full breakdown of the Current Trajectory and Low Cost High Renewable scenarios can be found in Annex B.

Figure 22: Change in generation from Current Trajectory to Low Cost High Renewable



A low cost high renewable power system - summary

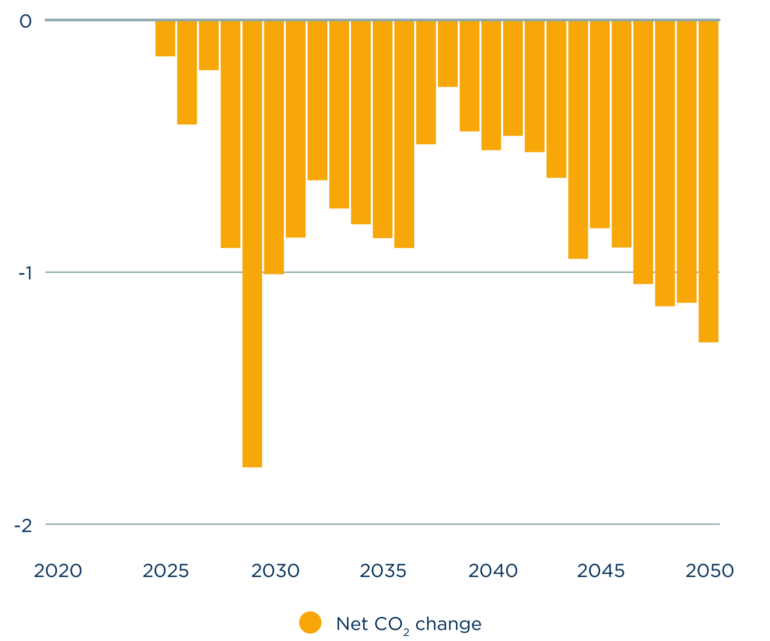
Generation mix

The main changes in the **generation mix** are:

- Increase in offshore wind generation, with an additional 86TWh in 2050. In addition to the large amounts of new capacity, this is made possible due to the additional long-term storage and electrolyser capacity.
- Increase in gas CCS generation or around 15TWh per annum. Flexible gas CCS alongside low-carbon hydrogen generation complements the additional offshore wind generation, reducing the need for baseload nuclear capacity.
- Reduction in nuclear generation (69TWh in 2050), with no new nuclear capacity included beyond 2030.
- Increased electrolyser utilisation is represented as negative generation (30TWh by 2050). This allows for lower levels of renewable curtailment, and an increase in green hydrogen production.
- Interconnector exports are reduced (shown as an increase in Interconnector generation), with excess renewable generation utilised in green hydrogen production and long-term storage rather than exported.
- Solar generation is increased despite no change in capacity, with electrolysis and long-term storage reducing curtailment.

Carbon emissions

Figure 23: Change in carbon emissions, mtCO_2e from Current Trajectory to Low Cost High Renewable



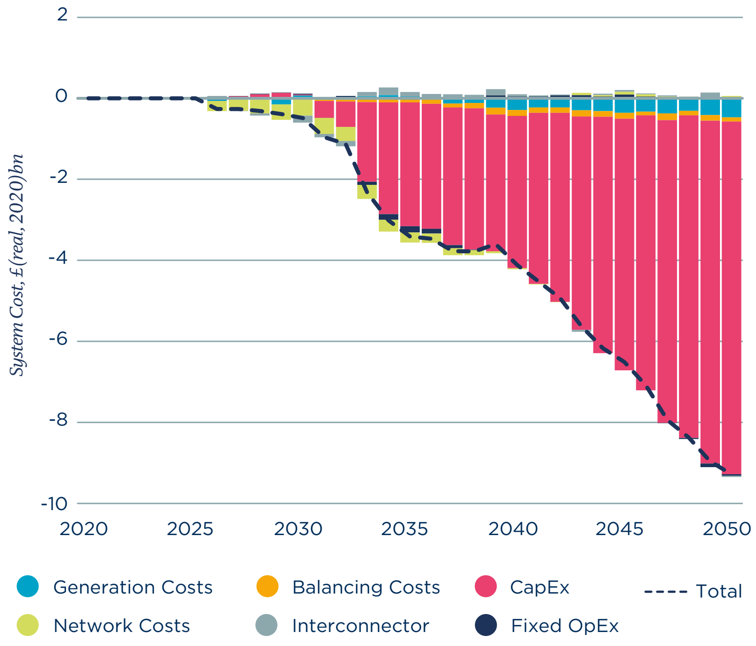
Between 2025 and 2050 carbon emissions are reduced by 19.8mtCO_2e, with 7.5mtCO_2e ahead of 2035. This is due to two main reasons:

- The faster build out of renewables, low-carbon gas and long duration storage relative to nuclear means emissions are reduced in the period prior to 2035
- By 2050 power sector emissions are similar, but the greater production of green hydrogen offsets emissions in producing blue hydrogen elsewhere in the economy.

A low cost high renewable power system - summary

System costs

Figure 24: Change in system cost from Current Trajectory to Low Cost High Renewable



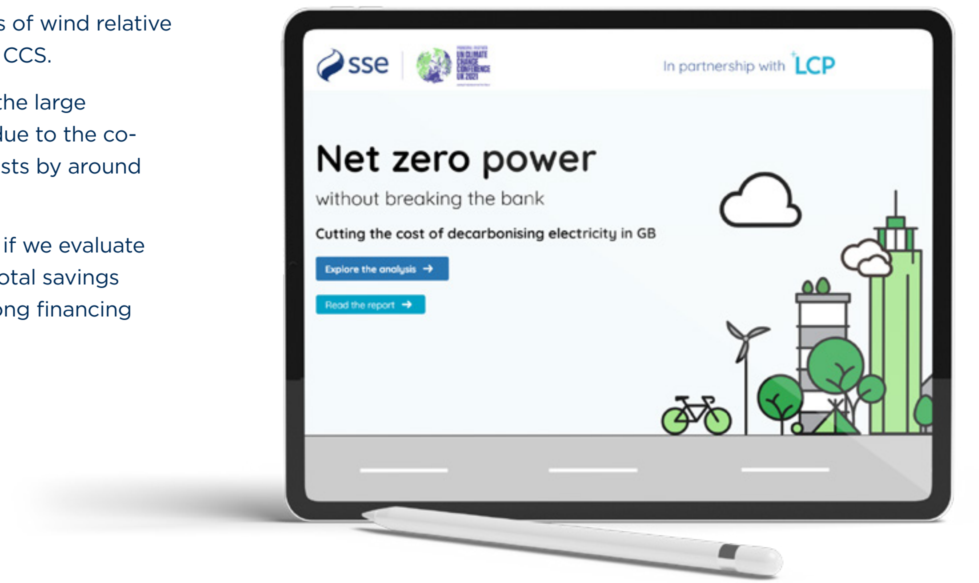
The key changes in the **system costs** are:

- Large reduction in capital costs, almost £10bn per annum by 2050. Note that capital costs are accrued as financing costs over the economic life of the asset, rather than during construction (consistent with approach taken by BEIS), so the capital costs increase steadily over the period to 2050.
- Generation costs decrease slightly, with the lower costs of wind relative to nuclear offsetting the additional fuel costs from gas CCS.
- Network cost changes are kept to a minimum despite the large amounts of additional offshore wind capacity. This is due to the co-ordinated offshore network, which reduces network costs by around £1bn per annum by 2050.
- There are also a further £28bn in savings in NPV terms if we evaluate through to 2060 (not shown on the chart) taking the total savings up to £76bn if looking out to 2060, partly due to the long financing periods of new assets.

Explore the data

Take a deep dive into the analysis behind this report. Visit our interactive website that explores the pathway to achieving a net zero power system in more detail.

netzeropower.lcp.uk.com



Annex A Whole system cost approach

The whole system cost framework was developed by Frontier Economics, DECC and LCP in 2015. It is incorporated into LCP's EnVision modelling framework, including the Dynamic Dispatch Model (DDM) which is currently used by BEIS and maintained by LCP.

System costs represent the total cost of building, operating and maintaining the power system and are made up of the following components:

When reporting system costs in NPV terms, a 3.5% social discount rate is used, consistent with the UK government assumption.

Generation costs

Costs associated with meeting GB electricity demand hour to hour, i.e. wholesale market dispatch. These include:

- Fuel costs - the total cost (consisting of the market price and transportation charges) of any fuel utilised for power generation.
- Carbon costs - the cost of carbon emissions priced at the social cost of carbon, this may differ to the current market price of carbon.
- Variable Operating and Maitenance (VOM) costs - O&M costs that vary with the output of the generator.
- Interconnector costs - see below

Capacity adequacy costs

Costs associated with ensuring there is sufficient capacity on the system to meet peak demand. These include:

- Capital expenditure (CapEx) costs - include pre-development, construction and infrastructure costs. The system cost is the cost of financing these investments, so the capital costs are spread across the economic lifetime of each plant based on the hurdle rate assumed for each technology.
- Fixed operating costs - O&M costs that do not vary with the output of the generator.
- Unserved energy costs - the additional cost for any MWh shortfall once all energy and system balancing actions have been accounted for. Each MWh is priced at £17,000 which is the current UK government assumption for the Value of Lost Load (VoLL).

Balancing costs

Costs associated with balancing supply and demand, created due to uncertainty in output from generation and demand. Includes energy balancing and cost of providing system services (reserve, frequency response, inertia) to ensure a stable system.

Like generation costs, the system costs include Fuel, Carbon, VOM and Interconnector costs.

Network costs

Cost of maintaining, reinforcing and extending the network.

Includes transmission and distribution network costs.

Interconnector costs

Costs and revenues associated with electricity imports and exports from neighbouring markets. Interconnectors can be treated in two ways:

- External to GB system in which case costs are calculated as the net import in each settlement period multiplied by the wholesale price in GB.
- Internal to GB system in which case costs are calculated as the net import in each settlement period multiplied by the wholesale price in the foreign market plus the capital and fixed costs of the interconnector.

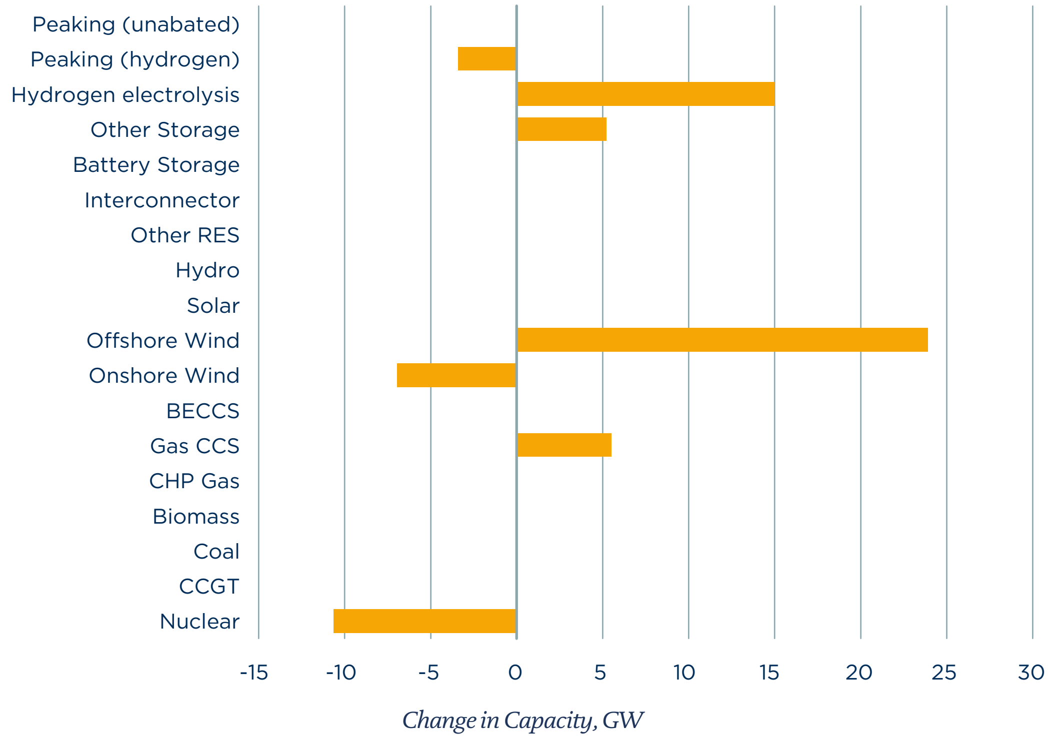
In this analysis we have assumed a 50:50 mix of the above approaches.

Annex B Capacity & generation

The modelled capacity mixes for 2050 for the Current Trajectory and Low Cost High Renewable scenarios are shown below.

Table 1: Capacity in 2050

Technology	Current Trajectory (GW)	Low Cost High Renewable (GW)	Change (GW)
Nuclear	15.0	4.4	(10.7)
CCGT[8]	0.4	0.4	-
Coal	-	-	-
Biomass	1.0	1.0	-
CHP Gas[8]	0.4	0.4	-
Gas CCS	9.5	15.0	5.5
BECCS	2.5	2.5	-
Onshore Wind	31.7	24.8	(6.9)
Offshore Wind	73.0	96.9	23.9
Solar	51.0	51.0	-
Hydro	1.9	1.9	-
Other RES[9]	2.8	2.8	-
Interconnector	15.5	15.5	-
Battery Storage	15.3	15.3	-
Other Storage[10]	10.1	15.3	5.2
Hydrogen electrolysis	15.0	30.0	15.0
Peaking (hydrogen)[11]	71.1	67.7	(3.4)
Peaking (unabated)	-	-	-

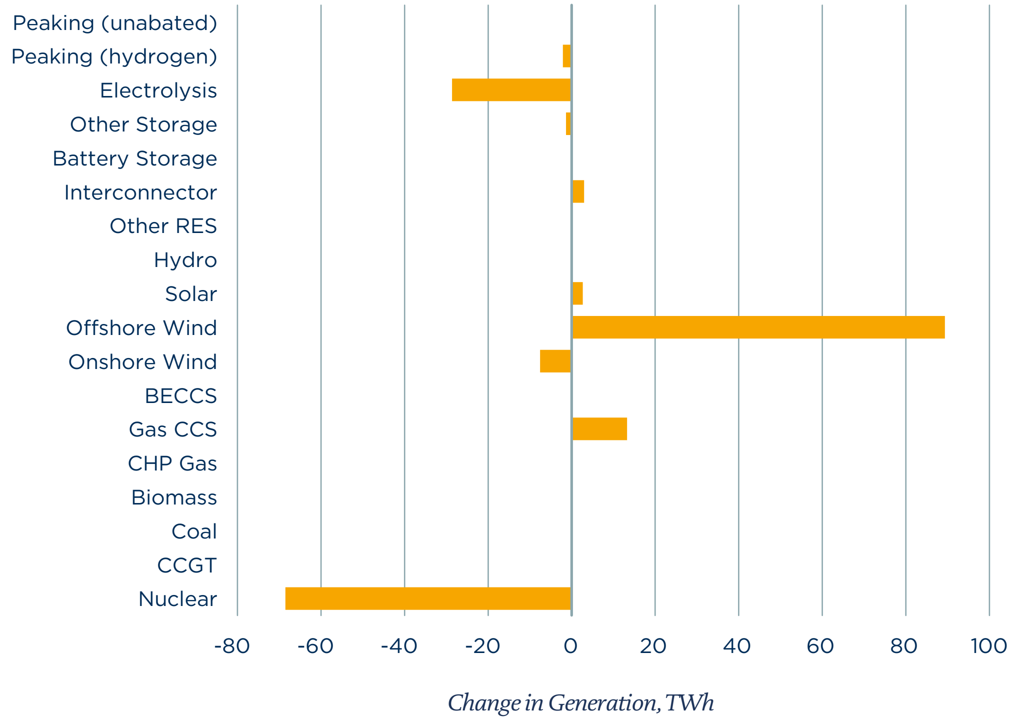


[8] Expectation is that capacity will blend up to 50% hydrogen, or be decarbonised fully with bio or synthetic methane
[9] Includes energy from waste and marine
[10] Includes pumped storage, compressed air and liquid
[11] Expectation is that capacity will largely be capable of 100% hydrogen combustion

The modelled generation mixes for 2050 for the Current Trajectory and Low Cost High Renewable scenarios are shown below.

Table 2: Generation in 2050

Technology	Current Trajectory (TWh)	Low Cost High Renewable (TWh)	Change (TWh)
Nuclear	97.4	28.9	(68.6)
CCGT[12]	0.1	0.1	-
Coal	-	-	-
Biomass	0.1	0.1	-
CHP Gas[12]	0.1	0.1	-
Gas CCS	20.5	33.7	13.2
BECCS	17.0	17.0	-
Onshore Wind	72.1	64.5	(7.6)
Offshore Wind	341.5	430.8	89.3
Solar	39.7	42.4	2.7
Hydro	5.2	5.2	-
Other RES[13]	16.8	16.7	-
Interconnector	(52.5)	(49.5)	3.0
Battery Storage	(1.7)	(1.6)	-
Other Storage[14]	(1.6)	(3.0)	(1.4)
Electrolysis	(33.3)	(61.9)	(28.6)
Peaking (hydrogen)[15]	69.4	67.3	(2.1)
Peaking (unabated)	-	-	-



[12] Expectation is that capacity will blend up to 50% hydrogen, or be decarbonised fully with bio or synthetic methane
[13] Includes energy from waste and marine
[14] Includes pumped storage, compressed air and liquid
[15] Expectation is that capacity will largely be capable of 100% hydrogen combustion

Annex C *Commodity & demand assumptions*

The input assumptions for gas and total carbon (ETS and CPS) prices as well as total annual demand and peak demand are shown below.

Figure 25: Carbon and Gas prices used

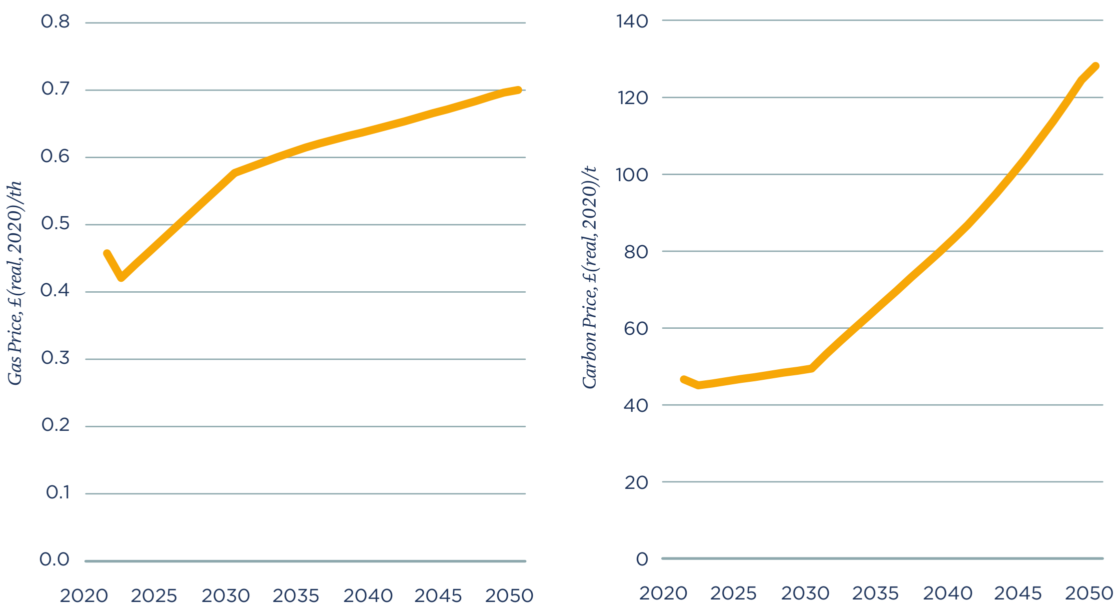
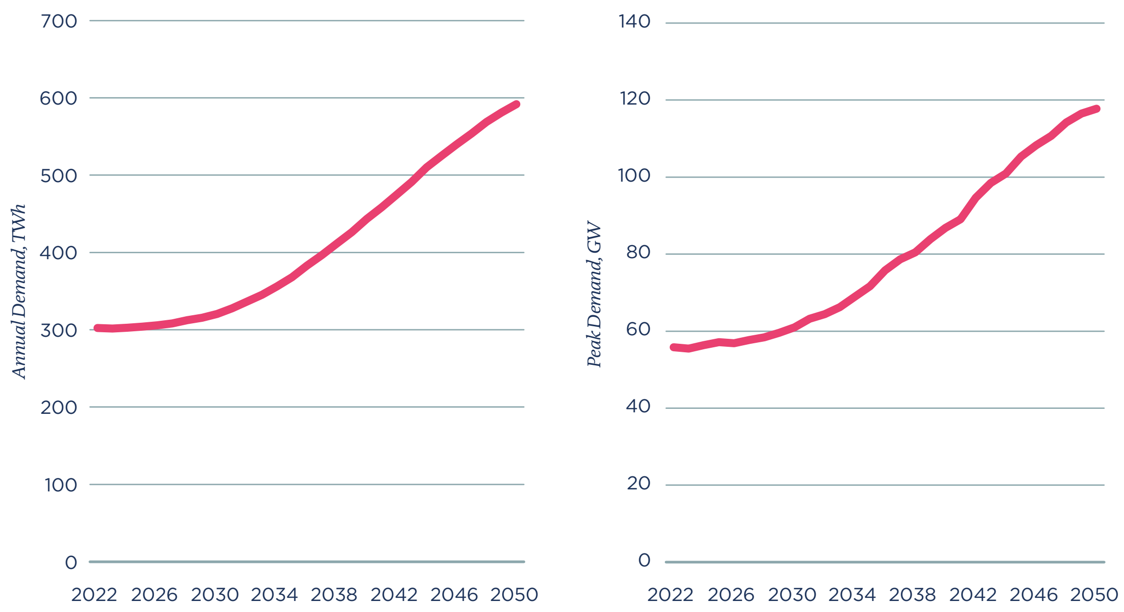


Figure 26: Annual Demand and Peak Demand assumptions used



Annex D Technology assumptions

The CapEx, Fixed OpEx and hurdle rate assumptions used in this analysis are detailed below, these have been compiled based on the latest BEIS generation cost reports and accompanying Mott MacDonald storage cost report.

Table 3: Technology Assumptions

	Hurdle Rate	CapEx, £(real, 2020)/kW			Fixed OpEx, £(real, 2020)/kW		
	%	2030	2040	2050	2030	2040	2050
Nuclear	8.9%	4,787	4,787	4,787	80	80	80
CCGT	7.5%	543	543	543	14	13	12
Coal	9.2%	3,338	3,338	3,338	80	80	80
Biomass	7.9%	2,607	2,607	2,607	73	70	65
CHP Gas	9.0%	754	754	754	31	30	28
Gas CCS	9.0%	876	876	876	27	23	23
Other RES	9.9%	5,564	5,564	5,564	146	146	146
Onshore Wind	5.2%	943	943	943	25	24	23
Offshore Wind	6.3%	1,562	1,354	1,147	41	39	37
Solar	5.0%	406	302	95	6	5	4
Pumped Storage	5.4%	1,145	1,120	1,104	15	15	15
Battery Storage	7.2%	276	220	191	5	4	3
Peaking (unabated)	7.1%	399	399	399	11	11	10
Hydro	5.4%	3,384	3,384	3,384	50	50	50
Electrolysis	7.0%	614	501	410	1	0	0
Peaking (hydrogen)	7.2%	491	491	491	7	7	6

Annex E

Modelling framework used

This modelling was conducted using LCP's EnVision modelling framework. This framework has been developed inhouse at LCP over the past 10 years. It is used by BEIS for its long-term GB market projections and policy impact studies and National Grid for its security of supply modelling. It has also been used by Ofgem for its network charging analysis, and is used by the LCCC (CfD counterparty) in its forecasts to project CfD costs and set supplier levies.

For this project LCP's stochastic dispatch model was used to simulate the wholesale and balancing markets. Multiple simulations (20+) of each year were run under different intermittency and demand profiles and randomised plant outages. This stochastic approach captures tail events, while not under or overestimating their likelihood. This is important for wind assets (even those that are CfD-supported) as under extreme conditions of high renewable output the assets may be curtailed due to zero or negative prices.

In all our modelling we employ a fundamentals-driven approach. This approach is important in a system which will evolve dramatically over the modelling period, with significant increases in renewable penetration and the continued emergence of flexible technologies. Though calibrated against historical market outcomes, this fundamentals-driven approach is robust to this evolution, and captures important dynamics such as the cannibalisation of revenues through increased competition.

Limitations of this anaysis

Given the magnitude of the system benefits presented, we believe the overall conclusions presented in this analysis are robust. Where possible we have relied on widely respected published sources for our assumptions, and have kept proven, mature technologies central to our future capacity mixes to ensure the scenarios are credible.

However, as with all long-term modelling of this type, the results presented in this report are dependent on the assumptions used and the modelling methodology applied. Forecasts through to 2050 are subject to significant uncertainty, and the results of this analysis should be viewed with this in mind.

In particular, we believe it is important to be clear on some of the key areas of uncertainty and limitations of the analysis:

- Technology costs (including hurdle rates) are based on current published views and these may change significantly in the future (we have used BEIS's Electricity Generation Costs 2020 publication where possible)
- The scenarios put proven, mature technologies central to ensure the pathways are credible. However, further new technologies may become competitive and play a bigger role than is assumed in this analysis.
- We have modelled the system under current market arrangements. With the exception of the reform to expand low-carbon support to include existing plant, this analysis has not assumed, or explored the impacts of, any other market reforms.
- The analysis did not explore every possible change or combination of changes that could be made to the system. As such, further reductions in cost are possible.

Contact LCP

For further information please contact our team at LCP.

Chris Matson
Partner

chris.matson@lcp.uk.com
+44 (0)20 7432 0674

Gurpal Singh Ruprai
Consultant

gurpal.ruprai@lcp.uk.com
+44 (0)20 3824 7425

Tom Porter
Partner and Strategy Director

tom.porter@lcp.uk.com
+44 (0)20 3824 7430

About SSE

For further information please contact our team at SSE.

SSE has the largest renewable electricity portfolio in the UK and Ireland, providing energy needed today while building a better world of energy for tomorrow. It develops, builds, operates and invests in low-carbon electricity infrastructure needed in the transition to net zero, including onshore and offshore wind, hydro power, electricity transmission and distribution grids, and efficient gas, alongside providing energy products and services for businesses. UK listed, SSE is a major contributor to the UK and Ireland economies, employs around 10,000 people and is real Living Wage and Fair Tax Mark accredited.

PRINCIPAL PARTNER UN CLIMATE CHANGE CONFERENCE UK 2021 IN PARTNERSHIP WITH ITALY

Alistair McGirr
Head of Strategic Policy
alistair.mcgirr@sse.com

At LCP, our experts provide clear, concise advice focused on your needs. We use innovative technology to give you real time insight & control. Our experts work in energy analytics, pensions, investment, insurance, financial wellbeing and business analytics.

Lane Clark & Peacock LLP
London, UK
Tel: +44 (0)20 7439 2266
enquiries@lcp.uk.com

Lane Clark & Peacock LLP
Winchester, UK
Tel: +44 (0)1962 870060
enquiries@lcp.uk.com

Lane Clark & Peacock Ireland Limited
Dublin, Ireland
Tel: +353 (0)1 614 43 93
enquiries@lcpireland.com

Lane Clark & Peacock Netherlands B.V.
(operating under licence)
Utrecht, Netherlands
Tel: +31 (0)30 256 76 30
info@lcpnl.com

LCP INSIGHT CLARITY ADVICE