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ENGINEERING NET ZERO

TECHNICAL REPORT

Engineering Net Zero

The magnitude of the challenge ahead is monumental; how do we move to a Net Zero system, whilst maintaining the economic and social progress that is demanded over the next 30 years?

Foreword

On 27 June 2019, the UK became the first major economy in the world to pass laws to end its contribution to global warming by 2050, putting clean growth at the heart of our modern industrial strategy. Whether it's the way we travel, heat our homes, generate our power or operate industrial processes – every aspect of our lives will, in some way, be touched by this revolution. The magnitude of the challenge ahead is monumental; how do we move to a net zero system, whilst maintaining the economic and social progress that is demanded over the next 30 years?

We've set out our seven key conclusions and recommendations put to policy makers to make the right decisions for a low carbon future. To some, the size of the challenge is too daunting to contemplate. In the face of overwhelming scientific evidence, others simply deny the issue. Across the pages of this report, we explore technologies, and industries to be developed, and the principal technical and commercial risks that could prevent us from achieving Net Zero 2050.

The risk of failure is very high, and there are immediate actions to take, particularly from the Government:

- The UK needs a rapid, well-coordinated programme across government
- We need to build energy infrastructure at a rate previously unseen across the country
- An optimal net-zero energy system will not be delivered by market forces alone
- The Government needs to urgently revisit financing models and reassess its risk appetite, to realise its commitment to nuclear new build
- We need increased capacity from renewable energy sources such as offshore windfarms, including leading on the development of floating offshore wind technology
- We have no Carbon Capture Storage industry, and our current pilot project must be accelerated; the projected mid-2020s date will be too little, too late
- And we need greater investment in hydrogen projects – 10 times more output

Throughout the report, we've stressed the word 'need'; there is urgency. We're targeting key policy makers, government and parliamentary groups, industry players and the wider supply chain – those who make the decisions, and those who are responsible for keeping the lights on. But also, we're urging you, as a reader, to be a vocal champion of the engineering world, rising to one of the most important environmental, economic and societal challenges of our time.

Chris Ball

Managing Director, Nuclear and Power
Europe, Middle East and Africa, SNC-Lavalin's Atkins business

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Executive Summary

Net Zero overview – 2050

The UK was the first major economy to pass laws to end its contribution to global warming and bring all its greenhouse gas emissions to Net Zero by 2050. However, the UK Government must act rapidly if it's to match its ambition with action.

The Committee on Climate Change (CCC) report, which advised the UK should set this target, set out a 'proof of concept' scenario for a future energy system. This showed that Net Zero by 2050 is theoretically possible, whilst recognising that further work is needed.

The challenge is not just an energy sector one and will not be saved by major energy projects alone; we must look at how we consume and use energy, in travel, heating and in industry.

Our 2050 energy mix is predicted to be made up of: 58% intermittent renewables, 22% Combined Cycle Gas Turbine (CCGT) & Carbon capture and storage (CCS), 11% nuclear, 6% bioenergy with CCS, and 3% others. The report sets out the roles of these, an Energy Systems Architect, system balancing and optimisation, and our seven key conclusions and recommendations.

Flexible approach to ultimate system configuration

Net Zero by 2050 is achievable but not without changes to the UK's energy mix and significant investment; it requires the building of 9-12GW of energy generation capacity per year, higher than anything the UK has achieved in the previous 50 years. Delivering this demands a 30-year programme, with an evolving and flexible approach to the ultimate system configuration.

An Energy System Architect (ESA) is required to plan and optimise the whole system

The 2050 Net Zero energy system will be highly complex. Effective system balancing is essential, and the optimal system will not be delivered without Government intervention. This should be based on a strategic view of the entire 'system architecture' and evaluation of the whole system cost, with the creation of an ESA critical to its success. But no plan is ever set in stone for the next 30 years: the ESA will need to be dynamic to global and domestic changes in generation, demand, performance, industry and technology.

Clean, reliable and consistent nuclear power is critical

Nuclear energy is a critical but currently undervalued element within the system. Nuclear presents a low technological risk but is significantly challenged by the current financial model. With declining UK gas production, nuclear offers the only firm power with assured security of supply and is an essential component for a stable, least cost, energy system.

A key role from Carbon Capture and Storage (CCS)

CCS is also critical to the proposed Net Zero scenario and represents the biggest risk to achieving it. The Net Zero scenario requires the UK to have four times the current global capacity by 2050, however the UK currently has no CCS industry and no firm plan in place to delivery this.

Increased capacity from renewables

Rapid growth of our offshore wind capacity is required, which is achievable but there are several risks, uncertainty regarding capacity factors, integration challenges, system balancing and stability, as well as concerns that costs may increase.

Greater investment in hydrogen projects

Hydrogen may serve as both an energy vector and an energy store. Net Zero assumes that 30% of the UK's energy will be delivered through hydrogen, with it contributing to industry decarbonisation, domestic heating and transportation. 80% of this would have to be produced by methane reformation (MR) which depends on CCS. This in turn greatly increases the risks associated with hydrogen's role in achieving Net Zero.

Energy Storage and System Integration

High renewable generation depends on firm power interconnectors, demand-side response and energy storage. However, there is currently no battery technology capable of grid-scale balancing storage – and there is no such technology on the horizon.

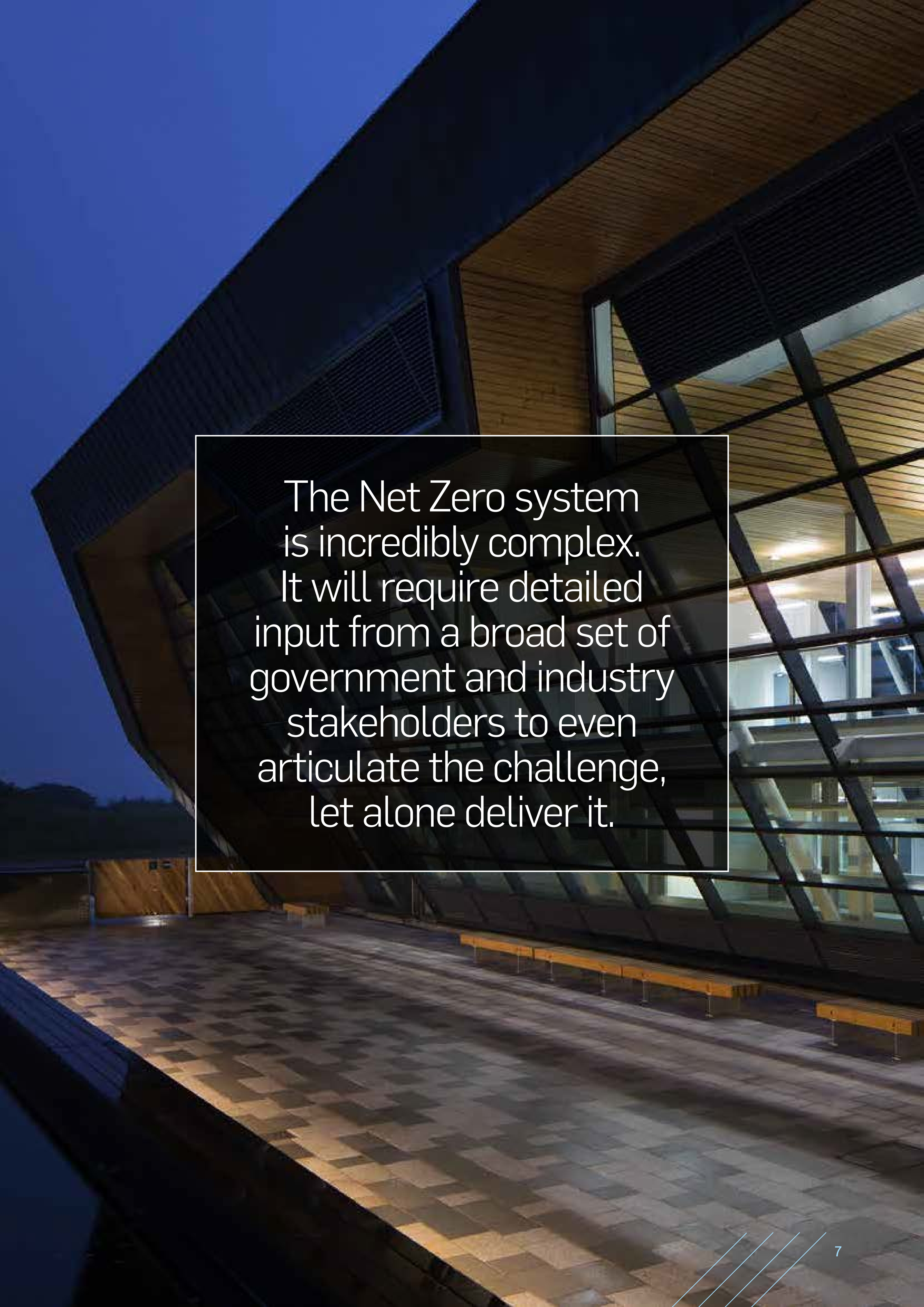
Recommendations

Some key recommendations include:

1. Early build projects for all recommended energy sources. This process will reduce construction time, enabling delivery at the lowest cost and minimising bills for the consumer.
2. Increased focus and investment in nuclear: urgently prioritise Government consultation on alternative financing models (RAB) for nuclear and develop innovative approaches to construction risk. Reviewing the electricity market and evaluating the impact of intermittent renewables on firm power pricing.
3. Expedite and fund pilot carbon capture and storage projects as quickly as possible.
4. Addressing the 'hidden costs' of system balancing and stability in offshore wind, developing UK floating wind technology and IP, and increased UK supply content.
5. Accelerating the current hydrogen research programme, with a minimum of two demonstration projects.
6. Ensuring the energy storage debate is grounded in current technology. It should be clearly structured on both the power achievable (MW to GW) and how much energy is stored (MWh).

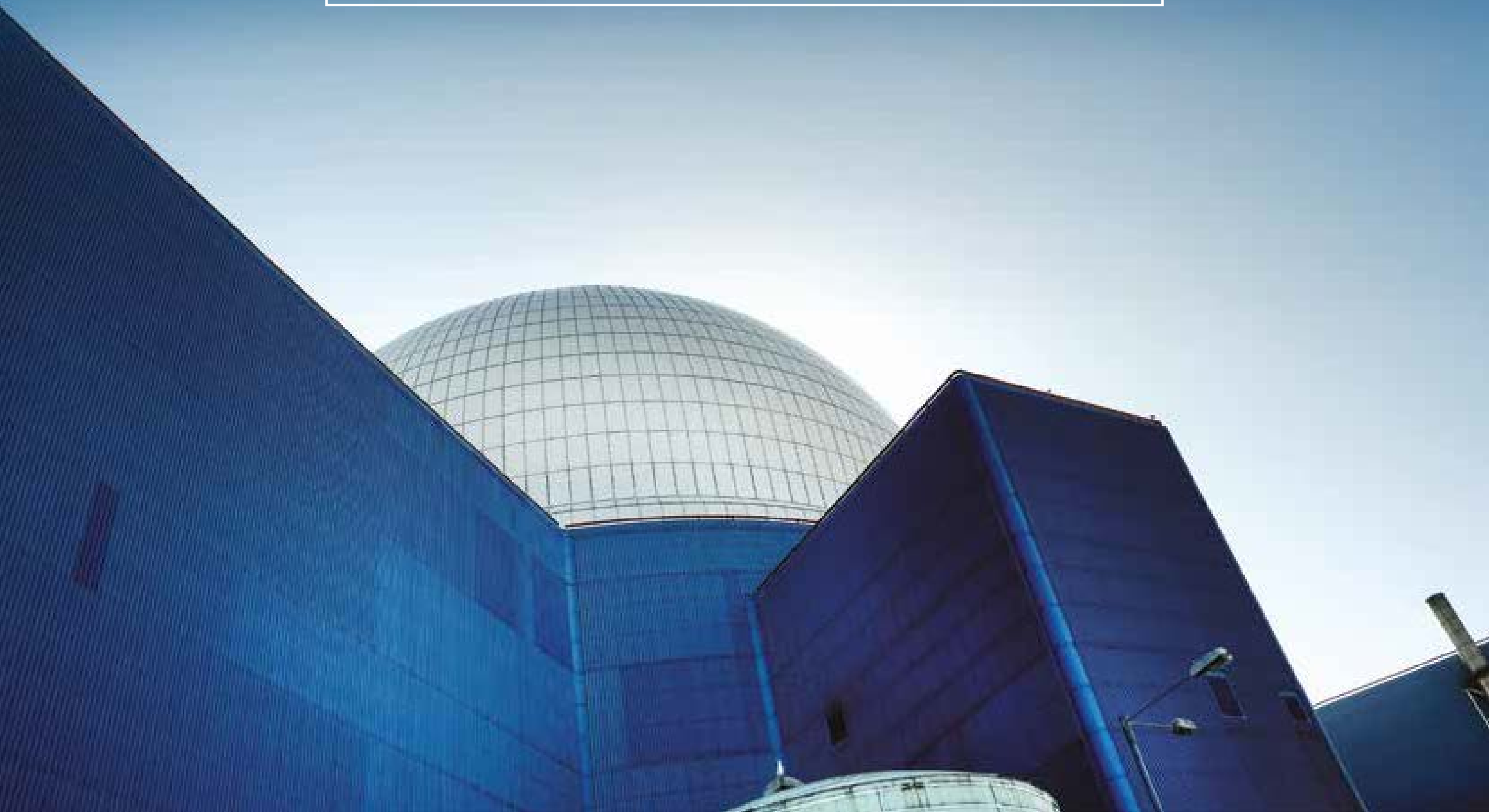
Ambitious, yet fundamental: without governmental action and investment, Net Zero 2050 is not possible – maintaining our current approach will mean that we will never reach Net Zero.

Net Zero can only be achieved through dramatic transformation of our entire energy system encompassing energy generation, heating, transportation and industry. It requires changes in how we use our land, how we travel and even what we eat. It will test our financial resolve with HM Treasury suggesting that the cost of these changes may exceed £1tn; however, the high cost of achieving Net Zero must be compared to the cost of doing nothing.



The Net Zero system is incredibly complex. It will require detailed input from a broad set of government and industry stakeholders to even articulate the challenge, let alone deliver it.

Ambitious, yet fundamental: without serious changes, governmental action and investment, Net Zero 2050 is not possible.



1. The Net Zero System

The Net Zero emissions target, officially defined as "Net Zero greenhouse gas emissions in the UK by 2050" [REF 3], is now a legally binding target of the UK Government.

There are numerous sources of credible modelling that set out scenarios for how a future UK low-carbon system might look. For this paper, we have used the Committee for Climate Change (CCC)'s report, Net Zero – The UK's Contribution to Stopping Global Warming [REF 3], and in particular its Further Ambitions scenario, as the basis for our work. Drawing on these sources, we have assessed the engineering implications of the future Net Zero system, and the pathways to achieving it.

CCC is the UK Government's advisory body on climate change and an authoritative voice in this field. In our approach, we recognise that CCC's Further Ambitions scenario provides a 'proof of concept' for a Net Zero system from now to 2050. As such, the mix and volume of system components is indicative. Nonetheless, the ambition of CCC's system is clear and allows us to articulate the engineering and commercial opportunities, risks and challenges as we see them today.

The Net Zero system is depicted in Figure 1. We have indicated a 'broad brush' assessment of the technical and commercial risk in each of the main thrusts of the system using a green-amber-red traffic light. These assessments are, of necessity, somewhat subjective and the bases of these judgements are briefly set out in Table 1.

The headlines associated with the Net Zero system are as follows:

- A significant increase in low-carbon electricity generation is required – specifically, a four-fold increase from 155TWh in 2017 to 645TWh in 2050.
- Hydrogen will play a key part in decarbonising heat and some transport – hydrogen use increases ten-fold, from 27TWh in 2017 to 270TWh in 2050.
- Carbon capture and storage (CCS) is a critical component – CCS capacity increases from zero in 2017 up to a potential 176MtCO_2 in 2050.
- Effective system balancing is essential – stability and continuity of supply require greatly increased flexibility and real-time management in a more complex system, with increased intermittent generation sources.

Figure 1 – Net Zero System - Main Thrusts and Risks

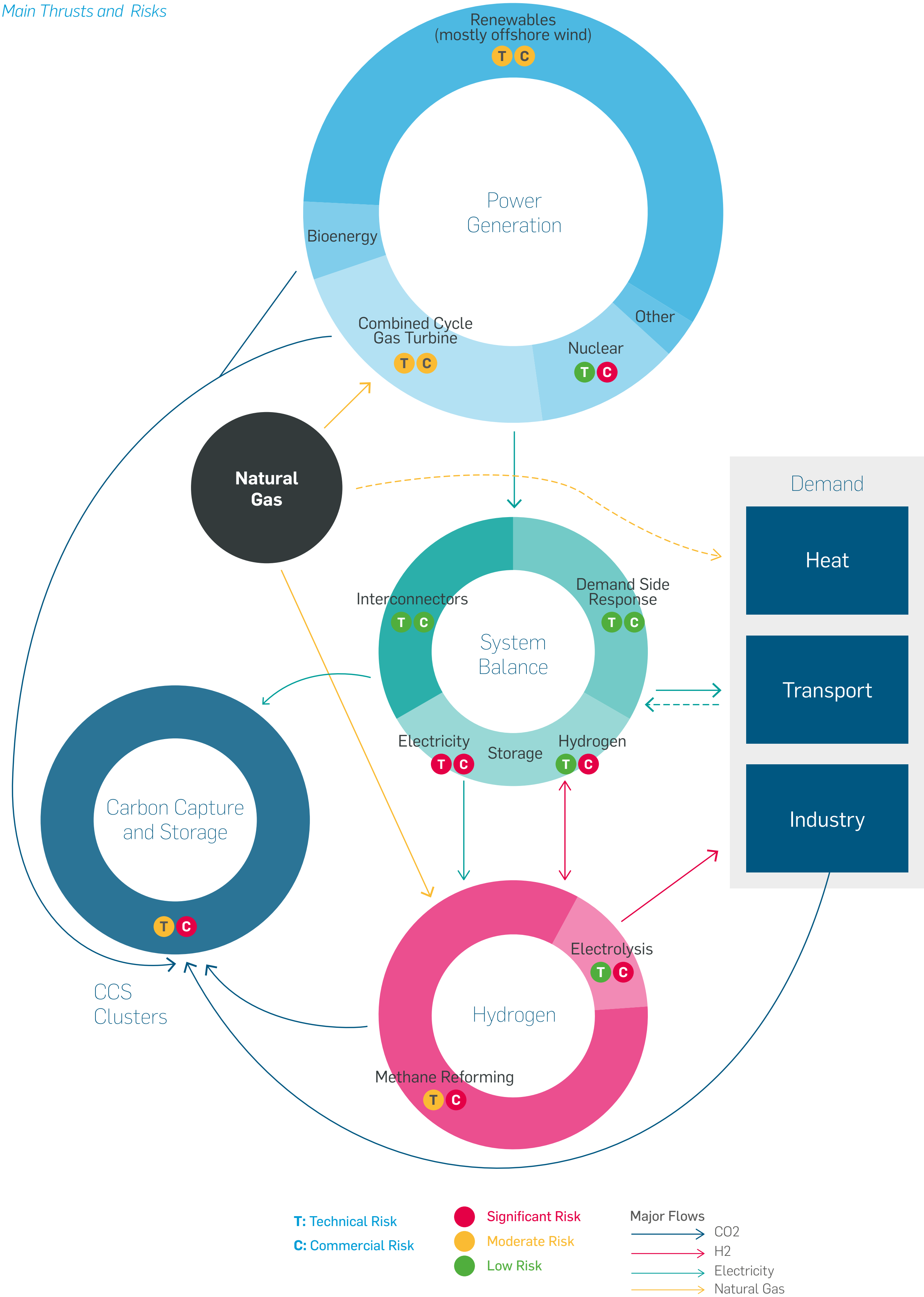


Table 1 – Basis of 'Broad Brush' Risk Allocation

Risk Ratings: R – Red, A – Amber, G – Green

System Component	Technology	Technical Risk	Rating	Commercial Risk	Rating
Power Generation	Renewables (Offshore Wind)	Current technology deployment is Green but 2050 deployment into deeper waters and assuming high fleet wide availability is considered Amber	A	Offshore wind on fixed foundations is becoming competitive at LCOE level and moderate system penetration, this would be Green. Movement to floating technology and increased integration costs at high system penetration give price uncertainty so Amber	A
	CCGT with CCS	CCGT is proven and Green but dependency on CCS in clusters increases risk to Amber	A	CCGT is currently cost competitive so Green but CCS will be expensive taking it to Amber	G/A
	Nuclear	Large PWR reactors are proven technology	G	Large nuclear is unaffordable and non-competitive under the current UK funding model.	R
System Balance	Interconnectors	Proven technology	G	No difficult commercial issues	G
	Demand Side Response	No technical issues	G	No difficult commercial issues	G
	Storage – Electricity	Grid scale inter-seasonal storage is only available through pumped storage for which few sites are available. All other technologies are immature	R	Costs of storage are high and value is not fully recognised in the current commercial framework. Large scale storage will need a different commercial framework.	R
	Storage – Hydrogen	Storage mechanisms are well understood, capacity could be a challenge depending on solution to seasonal heating demand variation	G	Recent market operation has not supported gas storage. A new market mechanism will be required to support investment at the required scale	R
Hydrogen	Methane Reforming (MR)	Current MR technology is well known and would be green. Dependency on CCS raises the risk to Amber	A	MR is totally dependent on implementation of CCS and this is currently considered a high risk	R
	Electrolysis	Current electrolysis technology is well established, thus green. However, current technology is uneconomic and technology development is required to be commercially viable, this is Amber	G/A	Current electrolysis is non-competitive and thus Red but if technology develops to reduce costs this moves to Amber	R/A
CCS	Integrated System	Each sub technology is well proven, but the integration of extensive multi-user systems may be a challenge	A	The commercial challenge of structuring multi-user systems, financing infrastructure and long-term liabilities make CCS commercial structuring a high risk	R

1.1. Net Zero Components

The future system components as summarised in Figure 1 and the headline changes are highlighted here. Electricity and hydrogen are the two energy vectors, with CCS acting as an enabler to achieve low-carbon outputs while still using energy from hydrocarbons.

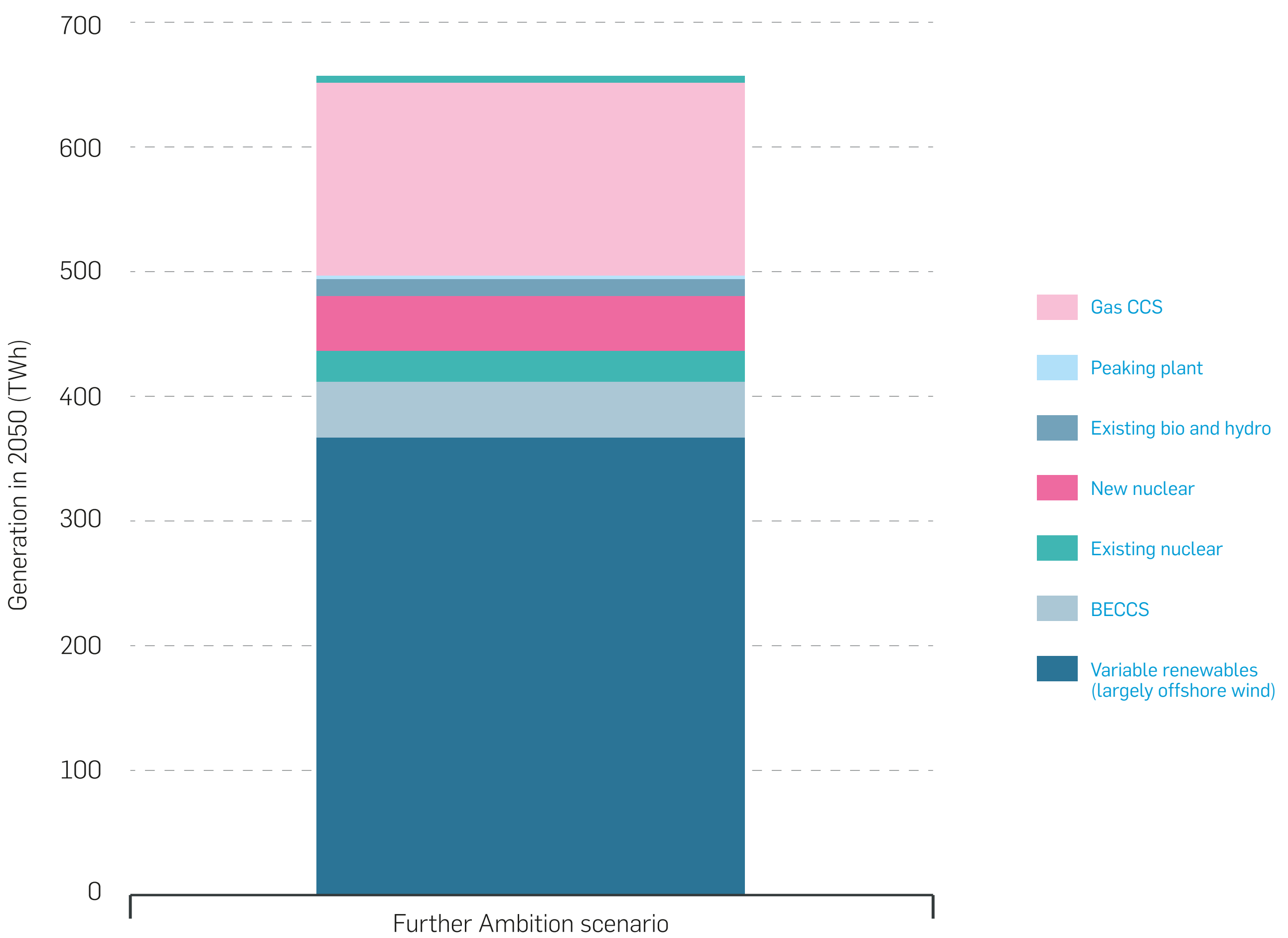
1.1.1. Energy Supply Side

Electricity Generation

Projected Generation	Estimated Peak Demand	Inferred Installed Capacity
645TWh	150GW	>280GW

The projected generation requirements in 2050 will be met by a mix of technologies, as illustrated in Figure 2. The engineering aspects of the generating components are considered in detail in Section 2.

Figure 2 – Illustrative generation mix for a low carbon power system in 2050 [REF 3]



Forecasts of electricity generation are presented in two ways, depending on the issue considered:

- For carbon volume and economic assessments, the total amount of power generated by each technology is the relevant criterion, usually measured in TWh/yr
- For system stability assessment and capital investment planning, the installed peak generating capacity required to meet forecast peak demand is the relevant criterion, usually measured in GW

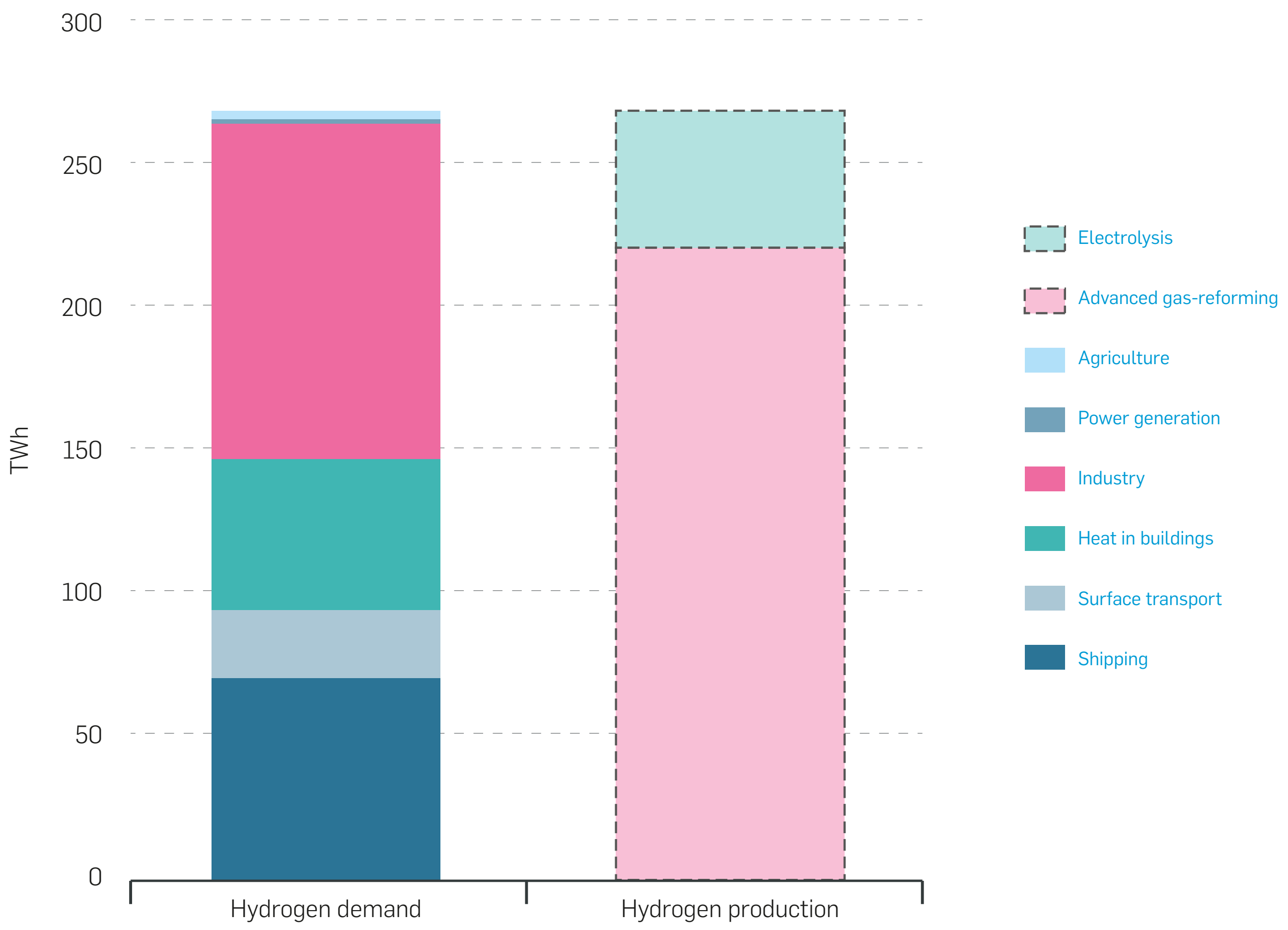
Net Zero modelling is primarily concerned with carbon and annual total power used. It is therefore not so explicit regarding peak capacity. From an engineering delivery perspective, required capacity is most relevant. We have therefore taken (or inferred) the required new installed capacities for each generating source as follows:

- Variable Renewables
  - Offshore Wind 75GW
  - Onshore Wind 20GW
  - Solar 80GW
- BECCS 5GW
- Nuclear 9GW (may be up to 35GW)
- CCGT w CCS 40GW
- Hydrogen production
  - Methane Reforming 30GW
  - Electrolysis 7GW

Hydrogen

The Net Zero system proposes up to 270TWh of hydrogen production based on a progression from steam Methane Reforming (MR) to Advanced Gas Reforming (AGR) and electrolysis, as shown in Figure 3. A detailed engineering assessment on hydrogen is made in Section 2.

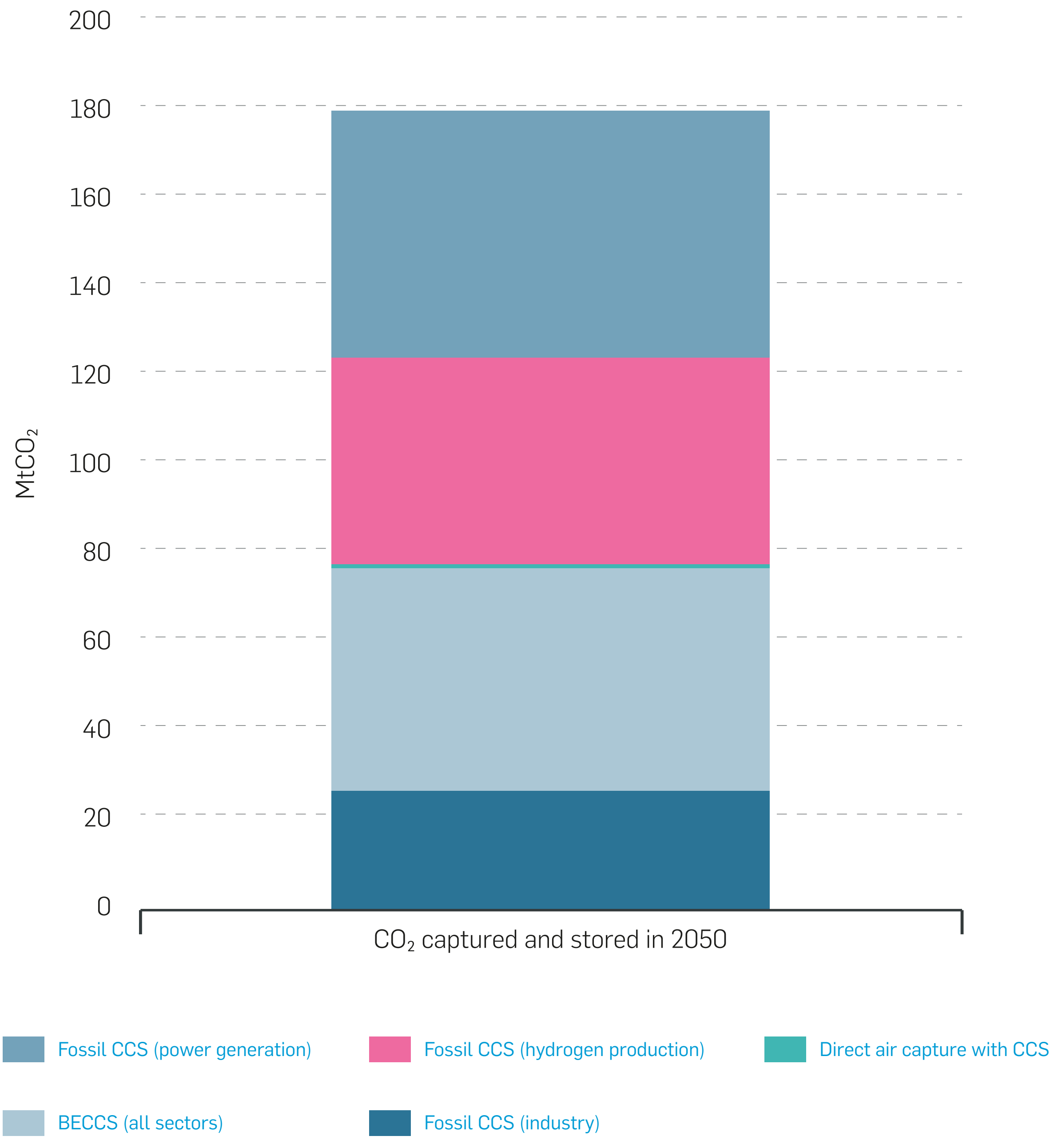
Figure 3 – Use and Production of Hydrogen in the Net Zero System [REF 3]



Carbon Capture and Storage (CCS)

CCS systems will need to capture, transport and store up to 176 $MtCO_2$ in 2050 as shown in Figure 4. In addition to CCS, carbon capture through afforestation of around 30,000 hectares per year (increasing woodland cover from 13% of the UK's land area to 17%) is included in the Net Zero scenario. Other reductions achieved through shifts in agricultural practice are also considered.

Figure 4 – Carbon Captured and Stored in 2050 scenario [REF 3]



1.1.2. Energy Demand Side

In this paper, our focus is on major capital projects within the core system components that will deliver the energy requirements to achieve Net Zero by 2050 (i.e. the supply elements of Figure 1). The supply side will be required to meet the variable future demands, which will look very different to what we see in today's energy system.

Some of the changes in demand characteristics are briefly summarised in the following sections. In later sections, we consider how an integrated system will manage these demands. Separate to this paper, our teams of experts will be publishing complementary reports on these demand areas to give greater consideration to the engineering challenges and opportunities.

Transport

Decarbonisation of the transport systems will be a significant factor in the Net Zero system. Battery electric vehicles will be the mainstay for standard cars; industrial vehicles (primarily HGVs) will switch to hydrogen fuel cells; rail will be electrified, and we may see the emergence of hydrogen fuelled trains. Shipping will be revolutionised using hydrogen or ammonia as a fuel; the aviation sector will drive innovation into engine and material efficiencies, and eventually new technologies may eliminate most carbon from aviation. Aviation may also be able to utilise liquid fuels derived from biomass, which may prove to be a more effective use of the biomass than using it to produce electricity.

Industry

Decarbonisation of industry will involve the use of hydrogen, electrification, CCS (including BECCS), low-carbon off-road mobile machinery, reductions in methane venting and leakage, as well as energy and resource efficiency. This will require deployment of low-carbon technology that is faster than the natural turnover rate of industrial assets. In some cases, alternative non-carbon processes may be adopted. The diverse range of industries (e.g. refineries, iron and steel, chemicals and construction) operating at varying scales and locations will further add to the challenge.

Heat

The greatest challenge is how to meet the needs for domestic heating, where demand varies enormously between summer and winter. The Net Zero scenario will require a balance (yet to be defined) between greater household electrification (heat pumps, electric radiators), increased district heating schemes and hydrogen (as a replacement for natural gas in boilers). Hybrid heat pumps that operate mostly on electricity, but require supplementary hydrogen in more extreme weather, may also be significant. A range of solutions for industrial heat are also being considered.

> The 2050 Net Zero energy system will be highly complex. Effective system balancing is essential, and the optimal system will not be delivered without government intervention.

2. Engineering Assessment

In this section, we provide our engineering assessment on the key components of the Net Zero system, as noted in Section 1. For each component, we address four key questions:

- What are the technologies that need to be engineered and deployed to meet the Net Zero target?
- Are these technologies well established and proven? If not, what technology development is required?
- Can the technologies be deployed in sufficient quantity and at pace to achieve the target? How will they be financed?
- What are the principal risks, both technical and commercial, that could derail efforts to achieve the target?

To provide a starting point for our assessment, we have provided an overview of the existing status of electricity generation in the UK. This overview forms a baseline against which we can assess the magnitude of future efforts.

2.1. A View of the UK's near-term generation capacities

The long-term trend in UK electricity generation (since 1990) from various sources is shown in Figure 5.

In Figure 5, the switch from coal to gas since 1990 is clearly shown, as is the introduction of a growing proportion of renewables over the past decade. Figure 9 at the end of this section shows the historical capacity building required to effect this change in fuel sources.

As of the end of 2018, DUKES reports that the UK's electricity generation capacity is just under 83GW (de-rated), which equates to around 106GW gross [REF 23]. While major power producers provide a significant majority of generation, there is a steady increase in small-scale local and decentralised generation. The make-up of the installed gross generating capacity is shown in Figure 6, where the gross capacity is 106.5 GW. To allow for intermittency, DUKES de-rates renewables; in the corresponding data, the de-rated capacities (as a percentage of gross installed) are: solar 16%, onshore wind 42%, offshore wind 43%. Therefore 34.9GW of intermittent renewables were de-rated to 11.45GW, with the de-rated total generating capacity estimated to be 83GW.

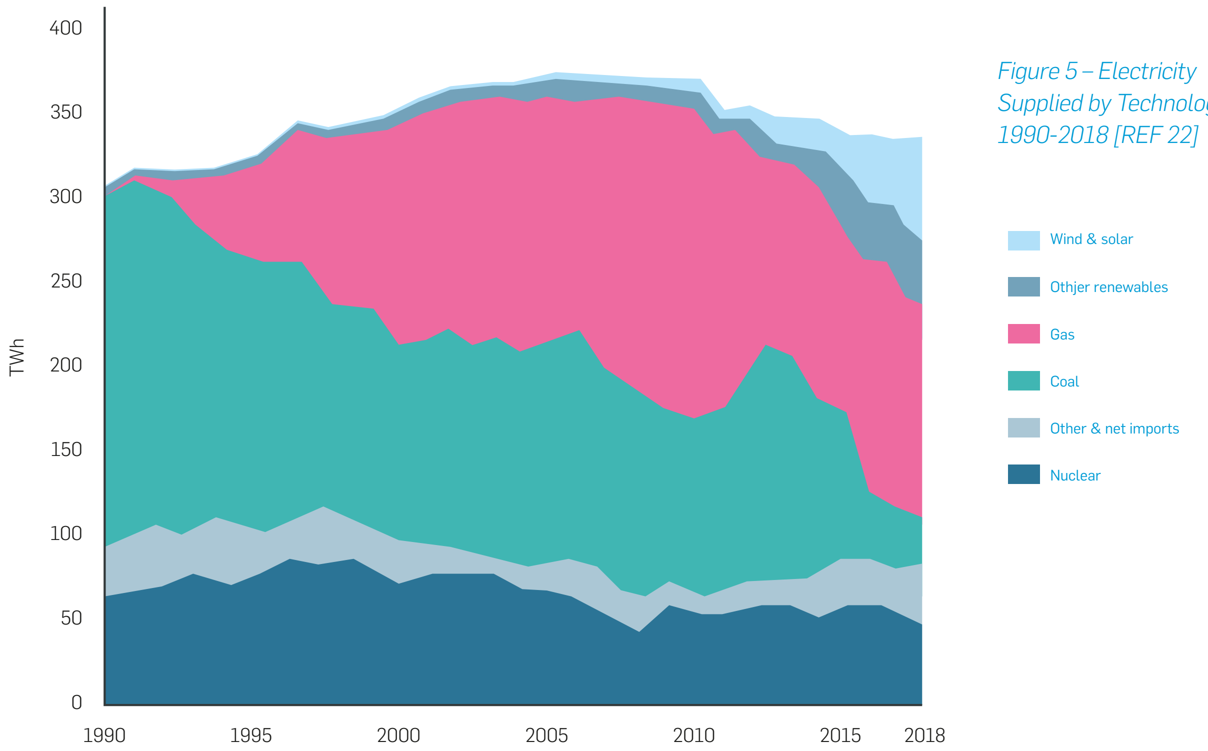


Figure 5 – Electricity Supplied by Technology 1990-2018 [REF 22]

Figure 6 – UK Gross and De-rated Generation Capacity 2018 (based on data from Chapter 5, Table 5.11 from [REF 23] and [REF 24]

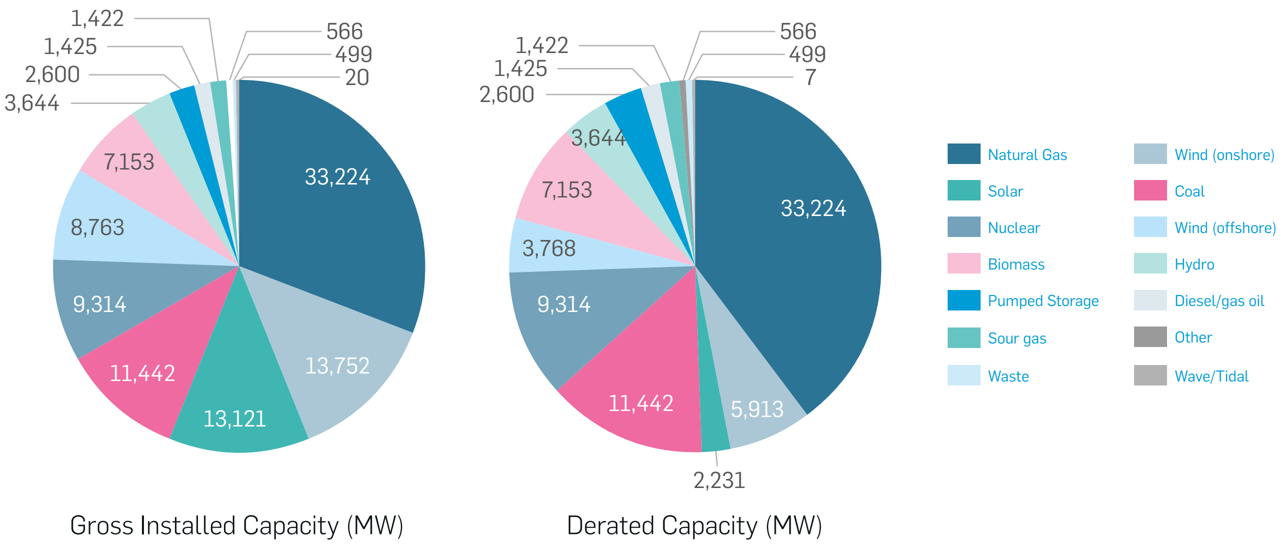


Figure 7 – 2018 Power Generation by Source (Total Generated was 332.9TWh) [REF 22]

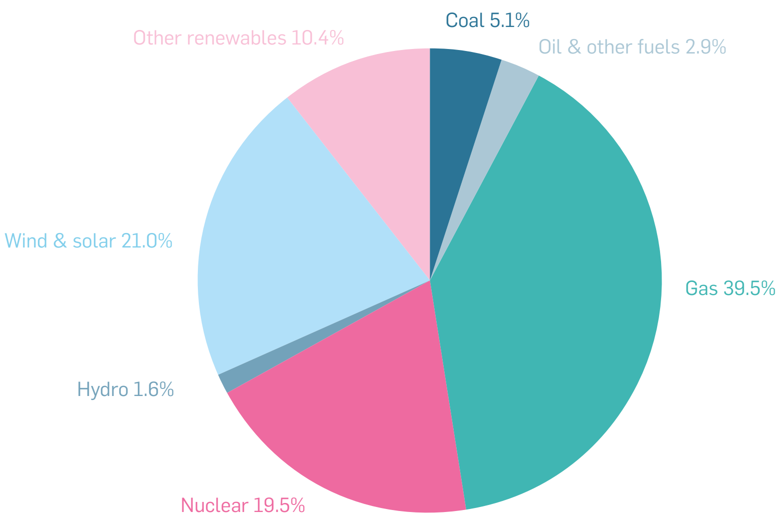


Table 2 – Comparison of Installed Capacity and Output (Values do not sum exactly due to rounding)

Generation Source	% Installed Capacity	% Generation Output
CCGT	30	39.5
Conv. Stream	17	8
Nuclear	9	19.5
Hydro	4	1.6
Wind and Solar	32	21
Other Renewables	7	10.4

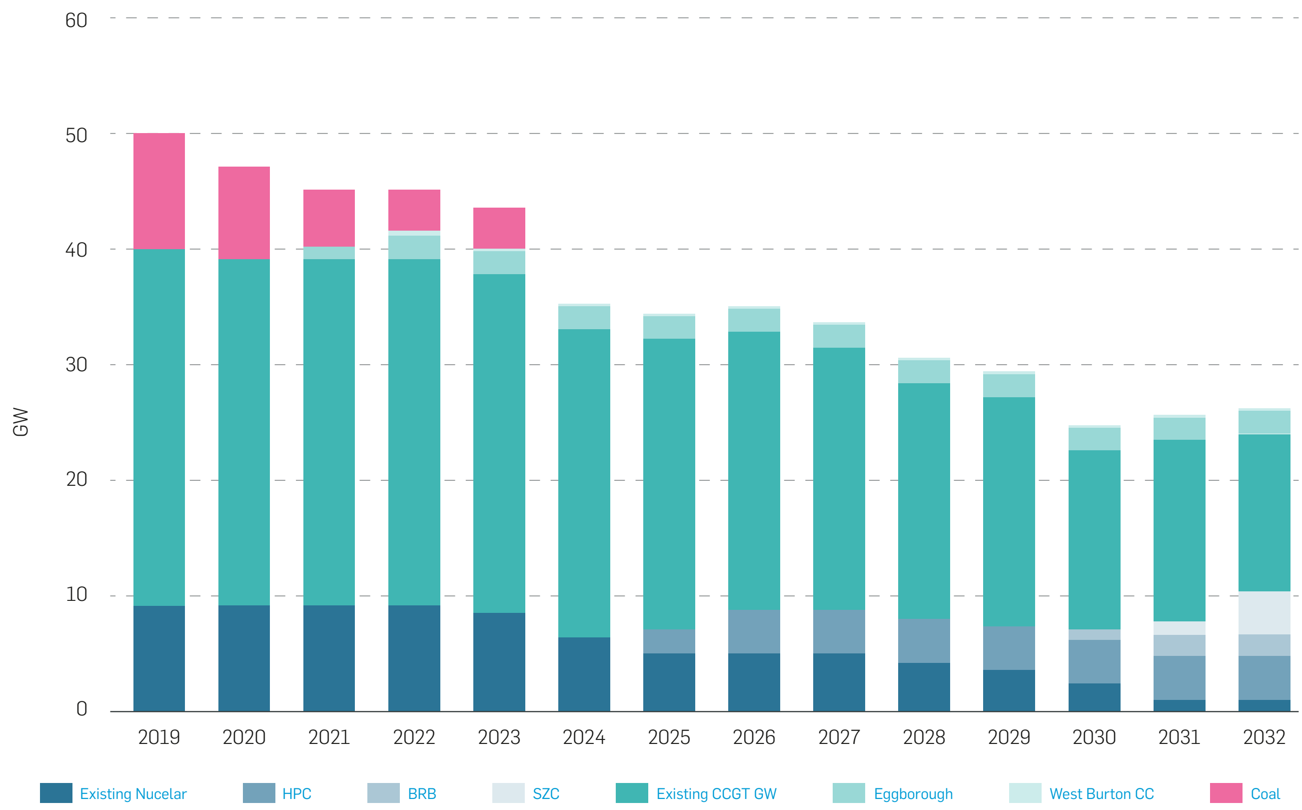
The comparison in Table 2 shows the percentage of power produced and the percentage of installed capacity, illustrating the significant difference between firm and intermittent power sources. Given the ranking priority awarded to renewables, these figures under-represent the power that could have been produced by firm sources. The total wind and solar capacity installed is more than three times that of nuclear (32% vs 9%). However, nuclear contributed almost the same amount of generated power. This highlights one of the key engineering aspects around firm and intermittent generation sources that we consider later in this document.

Looking forward to the near term, there are signs of capacity challenges ahead. These challenges are linked to the planned permanent shutdown dates of existing dispatchable (firm) plants, versus the expected dates for new generation sources to come online.

Projected firm capacity is expected to fall by 40% between now and 2032, despite the addition of three large nuclear plants and two large CCGTs, as shown in Figure 8. Therefore, the potential for instability in supply will increase just as the major restructuring of the system accelerates.

The major power disruption of 9 August 2019 caused by the near simultaneous failures of a small gas plant and a large offshore wind farm, illustrates that as firm capacity decreases, the system will have to be reinforced to manage more varied generation. It will also have to accommodate increased penetration of intermittent renewables.

Figure 8 – Projected Firm Generation Capacity. Developed using combination of data from [REF 20], [REF 23], [REF 25]



2.2. Deploying Net Zero Generation Capacities

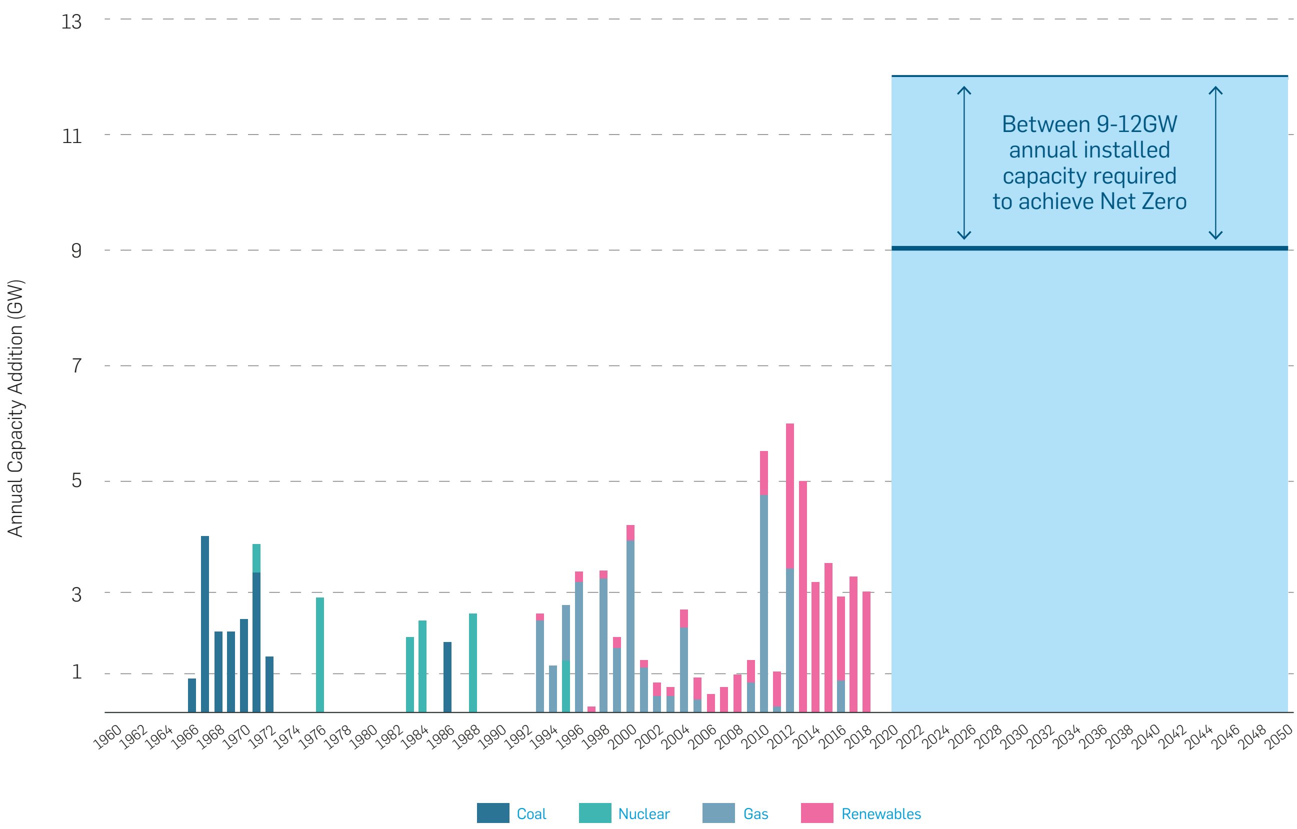
Net Zero estimates energy generation in 2050 of 645TWh, with a peak demand of 150GW, and potential installed capacity of around 280GW, up from around 100GW today.

Even if we only consider the electricity generation component of the future system, the deployment rate of new capacity will be unprecedented in the UK's history. As shown in Figure 9, the largest previous single gigawatt annual addition to the UK's generation capacity is around 6GW.

The potential annual capacity additions indicated in Net Zero are between 9-12GW annually for a sustained period.

Successfully implementing this sustained programme of works, which cuts across numerous generating technologies (as well as the development of other Net Zero components), will require innovative ways of working, from digital adoption and replication to modular construction techniques. It will also require a guiding mind that has accountability for the overall programme – what we refer to as the Energy System Architect (ESA). This concept, which is critical to Net Zero success, is described later in this paper.

Figure 9 – Historical UK Generation Capacity Building Compared with Future Projections [REF 26]



2.3. Engineering Consideration of the Net Zero Components

For the major components of the Net Zero system, we have assessed the engineering feasibility of the proposed levels of deployment in 2050. Here, we set out our assessments and findings for each component.

2.3.1. Renewables – Offshore Wind

Whilst we recognise Net Zero has included solar as part of the renewable energy mix, we have not considered this component within our assessment, and have instead focused on offshore wind. Two key characteristics of solar that have knock on effects to its effective contribution to the Net Zero system are that it is:

1. highly intermittent – leading to increased system integration costs which need to be factored in to system optimisation considerations;
2. seasonal – solar generation peaks through the summer months at the point where electricity demand is lowest. Credible large-scale, long-term electricity storage would need to be available and implemented to allow the system demands to benefit from solar at the appropriate times.

The overall benefit to the system of deploying tens of gigawatts of solar by 2050 is not clear to us based on the above, but we also recognise that the majority of this capacity would be deployed on a distributed basis and thus falls outside of the major programmes scope of our assessment.

What are the technologies that need to be engineered and deployed to meet the Net Zero target?

Net Zero places high dependence on a very large expansion of offshore wind – up to 75GW. It also assumes the capacity factor for turbines in 2050 is 58%. The first UK windfarms (now 15 years old) are operating at a lifetime capacity factor of ~31%. The very latest windfarms (installed in 2017/18) with more than one year of operational data are operating at a lifetime capacity factor of ~44%. The best performing windfarm in the UK is Dudgeon, which has been operating at a capacity factor of 49% [REF 27].

Today, capacity factors are increasing. This is due to improvements in the reliability of windfarms as we deepen our understanding of turbine technology. Hub heights are also increasing, enabling operators to leverage higher wind speeds. Meanwhile, increased swept blade volumes mean more wind is being captured, generating more megawatts even in calmer wind conditions.

Turbine manufacturers admit they have pushed the technology so hard, they are now finding that new improvements provide only diminishing returns. Therefore, to achieve capacity factors of 58%, there are key research areas that need to be explored. These are:

1. Improving reliability, with a focus on cables, blades and gearboxes.
2. Ensuring the roll out the 12MW-to-15MW turbine range, which will have increased hub heights and larger swept blade volumes.
3. Building developments in areas of high wind speeds.

Regarding point 3, 'areas of high wind speeds' will likely mean locating wind farms in deeper waters, which will require the UK to adopt floating technology. Initial evidence from one floating demonstrator (Hywind 2) shows its turbine to be running at a capacity factor of 57%, proving the locational advantage of deep-water floating technology over fixed assets.

Figure 10 shows the present and future development areas (including floating assets) for UK offshore wind. In order to access better wind resources, new fields will need to be located further out to sea. Potential areas under consideration for such developments are indicated.

As well as providing access to the greater windspeeds required for a 58%+ capacity factor, the deployment of floating technology in deeper waters will allow windfarms to be more spread out. This will help to ensure downwind developments aren't affected by wake losses.

And while deeper water developments will require enhanced transmission technologies (e.g. HVDC, MVAV, LFAC), these are well understood and should not present a barrier to progress.

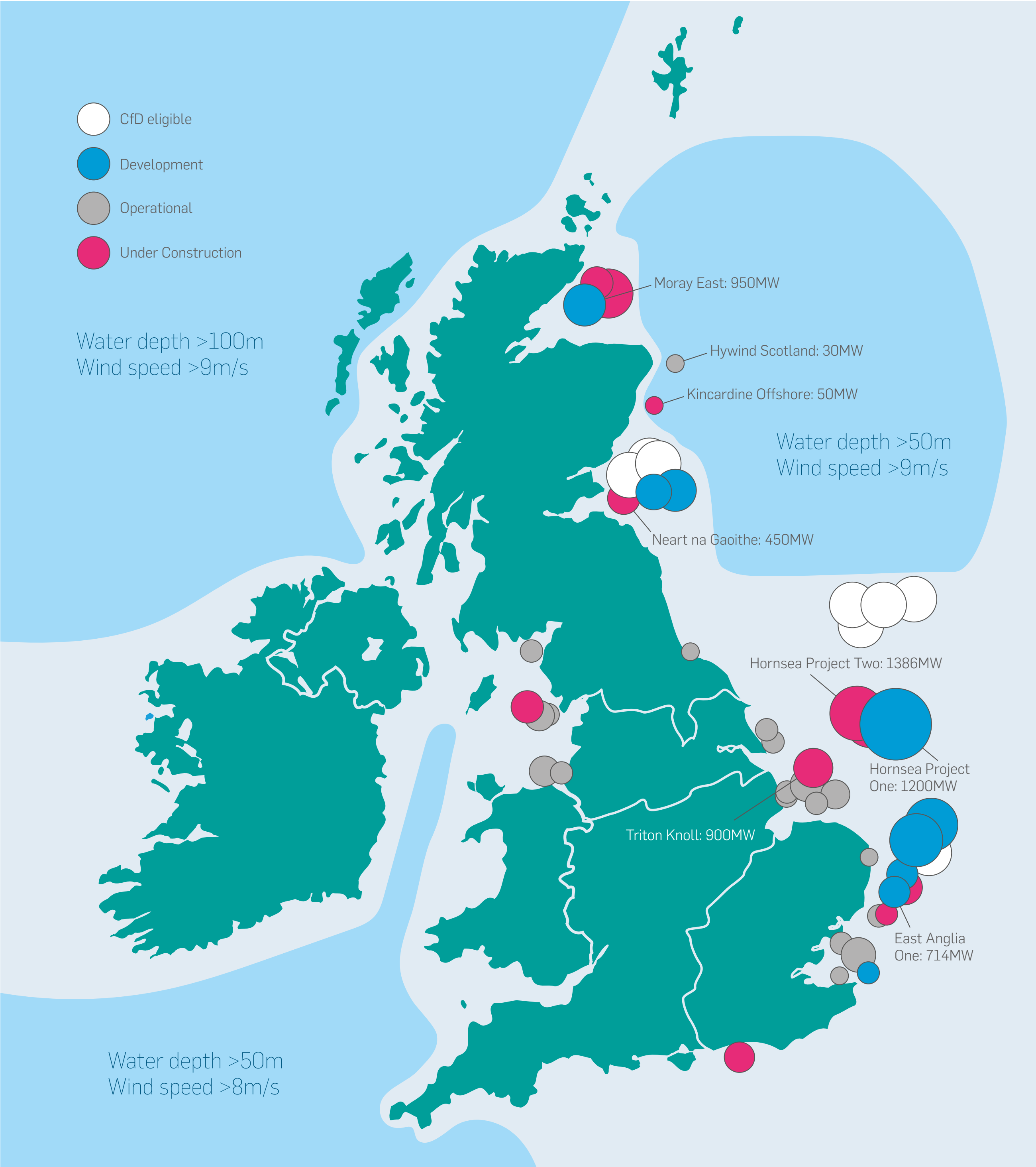


Figure 10 – Indicative floating wind locations compared to existing UK offshore portfolio [REF 28]

Are these technologies well established and proven? If not, what technology development is requirement?

Offshore wind technology is now well established and proven at the current scale. The current UK offshore wind market capacity is summarised as follows:

- Current installed capacity: 8.183GW
- Number of turbines: 1,975
- Projects in construction: ~3GW (Hornsea 1, EA1)
- Projects pre-construction: ~3GW (NNG, Moray East)
- Projects recently granted a 2019 Contract for Difference: 5.5GW
- Secured Pipeline: ~20GW

Turbines currently offered on the market include the Siemens 8.0MW, Vestas 9.5MW and GE 12MW. We also know that the Siemens 10MW is currently going through type acceptance, with a hopeful completion this year.

The exact total of gigawatts that can be extracted from UK waters is uncertain. Ranges between 300GW and 900GW are discussed at length in literature, even when considering shipping lanes, dumped ordnance, protected areas, proximity to shore, hydrocarbon facilities, wake loss effects and other factors. Therefore, the capacity of offshore wind is not limited by available resource or sites and presents great potential for future expansion.

Can the technologies be deployed in sufficient quantity and at pace to achieve the target? How will they be financed?

To answer these questions, we have considered a two-stage approach to addressing the deployment challenges facing developers in their efforts to reach 75GW of offshore wind capacity by 2050:

Stage 1 – 30GW by 2030

The UK Government has committed to two further Contracts for Difference (CfD) auctions in 2021 and 2023. The 2019 auction awarded 5.5GW of offshore wind. The 2021 and 2023 auctions will therefore likely address the rest of the 30GW 2030 target (i.e. 10GW).

It has been reported that at least one of the successful offshore wind farms in the 2019 auction round will use the Haliade-X 12MW turbine, and for the future 2021 and 2023 CfD rounds are expected to match or exceed this size.

Assuming the 2019 projects will start installation in 2023, over seven years 1,432 turbines will be installed – a rate of ~205 turbines per annum. The number of turbines installed in the UK in 2018 was 222.

Based on these details, we consider the technology and deployment rate for 30GW by 2030 to be feasible.

Stage 2 – 75GW by 2050

To continue the momentum, similar CfD auctions should ensure installation continues from 2030 onwards. Auctions (or an equivalent mechanism) from 2025 will therefore still be required.

If we assume turbine sizes are 13MW to 15MW over the 20 year-period, then the capacity that could be installed in this time (at the 2018 rate) could be 62GW. This would allow 45GW of new installed capacity and 17GW of replacement capacity for expired assets.

In terms of turbine technology, we know that 15MW+ machines are being researched, with 15MW test facilities being developed in the UK and US. Therefore, we consider the turbine technology and installation rate required to reach the 75GW 2050 target to be achievable.

What are the principal risks, both technical and commercial, that could derail efforts to achieve the target?

Risks

Costs for future CfD Levelised Cost of Energy (LCOE) are yet to be proven

As noted above, the substantial drop in CfD auction strike prices for the latest UK offshore wind farms is significant. However, commercial operability at these LCOE levels has yet to be demonstrated. When these farms connect to the grid in the 2020s the industry will be able assess the viability of the auction strike prices. This data can then be used to better model the 2050 system and therefore the potential penetration of offshore wind.

Floating offshore wind technology may drive up offshore wind costs

Demonstrator projects have shown that accessing sites with enhanced wind conditions can provide increased capacity factors. However, large-scale floating technology deployment is as yet unproven. CfD strike prices for the required technology may therefore increase to reflect the risk to developers.

The history of offshore wind cost improvement is shown in Figure 11. This figure represents the current or expected average £/MWh for all wind farms awarded CFDs to date [REF 29]. We doubt there can be a sustained and continued fall in cost, and indeed costs are more likely to rise as fields move to deeper waters where floating technology will be deployed (see Figure 12). Currently, the average cost of wind delivered across the fleet, contracted through CfD, is approximately £141/MWh.

Figure 11 – Average Offshore Wind LCOE for UK Farms with CFD Award (commissioned or planned)

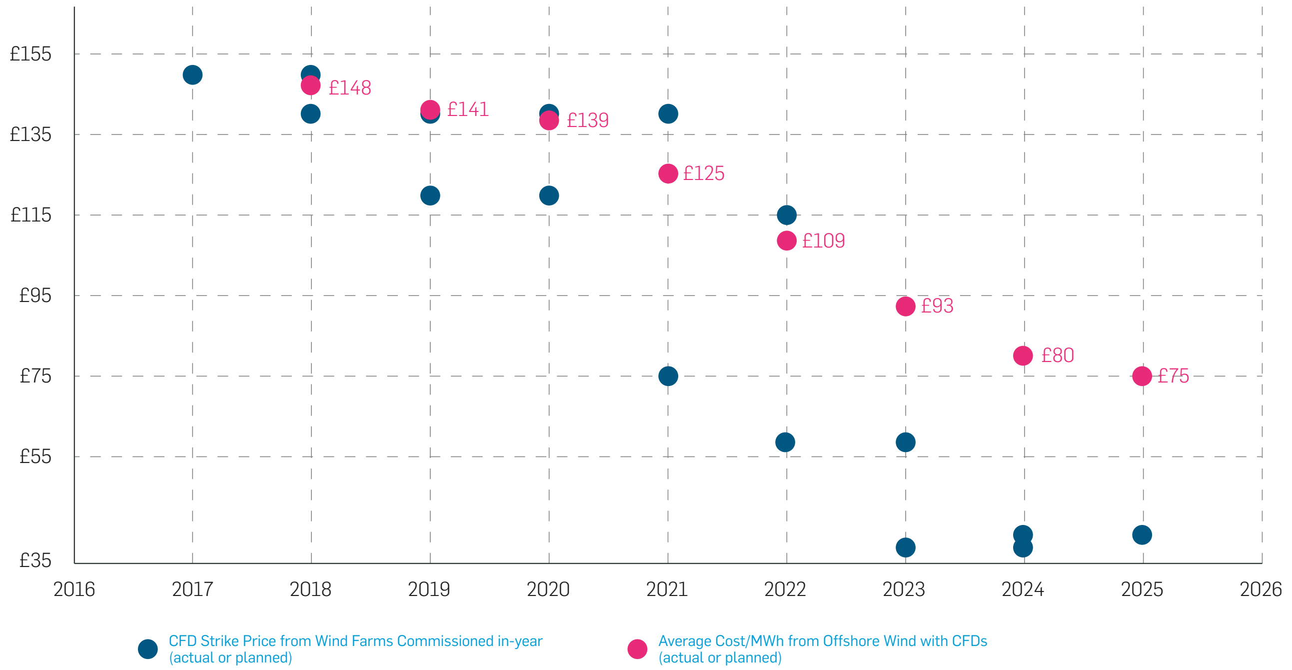
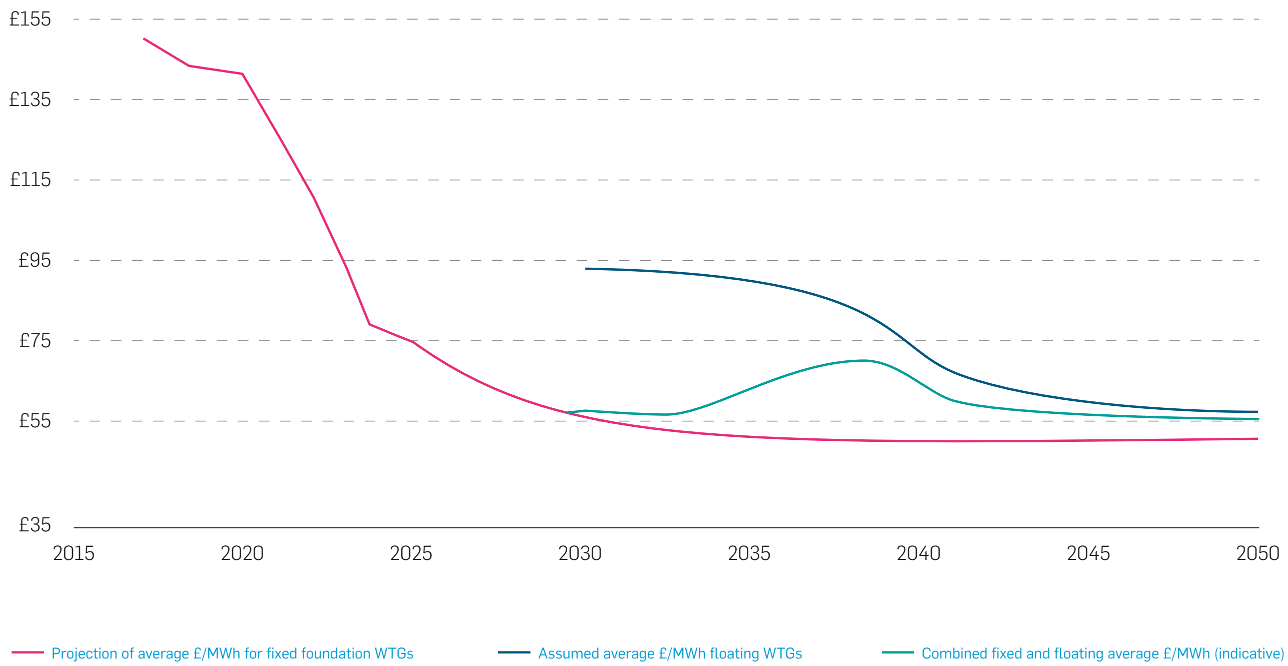


Figure 12 – Indicative average LCOE £/MWh for both fixed and floating offshore wind farms to 2050



As shown in the Figure 11, the average cost falls as the planned farms come online with lower strike prices. The average cost is projected to fall to just approximately £75/MWh by 2025, when the last of the currently contracted projects is commissioned (Seagreen).

The ORE CATAPULT [REF 28] indicates that by the late 2020s, fully commercial floating wind farms are expected to be deployable at scale. It is estimated that the strike price for these early floating commercial farms will be around £85/MWh. As more floating is deployed, the average £/MWh for the entire fixed and floating offshore wind fleet is expected to rise.

Supply chain capacity

The UK is part of a worldwide boom in offshore wind. The current supply chain will become stretched as the Far East, Europe and the US all embark on massive offshore wind programmes, which could lead to capacity limitations. To ensure we can hit our targets, we need to support the enhancement of our own UK supply chain. Developers, installation contractors, fabricators, OEMs and services companies should all be included in this process.

Objections from environmental bodies and fishermen

The more seabed and airspace that is used in offshore wind expansion, the greater the resistance will be from certain key stakeholders. We also understand that offshore wind developers are increasingly concerned about the availability of landfall sites for incoming cables to connect to the national grid.

Opportunities

Floating offshore wind presents an opportunity for UK industry to maintain its leading position in the global offshore wind market. Importantly, UK industry needs to capitalise on technology ownership.

2.3.2. Nuclear

Nuclear plants currently provide approximately 18% of the UK's electricity [REF 22]. Our current nuclear fleet is approaching the end of its working life (seven out of the eight operating stations will close between 2020 and 2030). Government policy for the past decade has been to replace this capacity, building up to 15GW of new nuclear power. However, large nuclear plants face major affordability challenges, with the cost of capital being a particularly sensitive issue. Government is working to address the difficulties caused by the current financial model and may introduce a RAB model, which could significantly reduce the LCOE of nuclear plant.

The Net Zero scenario appears to have dismissed current government policy and the ongoing work to address the financial model. It effectively curtails new nuclear in the mid 2030s after completion of the three plants currently in active development. Rather than keeping the technically proven nuclear option open Net Zero relies on CCS, of which we have zero current capability, or much larger amounts of renewables and, an as yet undefined, large storage capability.

What are the technologies that need to be engineered and deployed to meet the Net Zero target?

Net Zero assumes limited further deployment of large-scale Light Water Reactors (LWRs). This deployment would encompass the EPR at Hinkley Point C, Sizewell C and Bradwell B, following the operational launch of the world's first EPR in China in December 2018.

Although the Net Zero scenario includes limited nuclear deployment, it is a fact that nuclear and CCGT are the only viable options to provide firm low-carbon power in UK. CCGT is dependent on the successful implementation of CCS and therefore carries a significant risk. It is entirely possible that the least cost route to Net Zero will require considerably more nuclear than is currently being considered. If the UK's nuclear new build market is effectively shut down in the mid 2030s it will be both difficult and expensive to resurrect this capability late in the run-up to 2050.

It may be attractive to deploy reactors which are currently in development, either small modular light water reactors (SMRs) or Gen IV advanced reactors, again the capability to deploy these is seriously threatened by the assumed curtailment of new build in the 2030s.

Are these technologies well established and proven? If not, what technology development is required?

Gigawatt Scale Deployed Today

Large-scale (>1 GW) nuclear, using light water-cooled reactor technologies, are a proven generating technology with a global deployment history spanning seven decades. The most recent Gen III and Gen III+ reactors draw on this engineering heritage, also offering proven and reliable technology. Across the UK, there are suitable sites available for large-scale nuclear deployment, and there is a centralised planning framework in place to streamline their development. However, most of these sites would require upgrades in grid connections and infrastructure.

The UK's energy transmission system is currently set up for centralised large-scale generating technology. As such, it is already capable of integrating new nuclear capacity. The basic technology aspects of large-scale nuclear power are therefore considered low risk.

Future Nuclear Technologies

The nuclear industry has recognised the affordability challenge of large plants and has proposed SMRs as a viable alternative. Government has considered SMRs and undertaken a number of assessments of their potential. Indeed, in 2016/17, Atkins produced a Techno Economic Assessment to help facilitate appraisal and understanding in this area [REF 30].

In 2017 an initial competition to identify an SMR for the UK was quietly abandoned and the Government has since set out to identify and provide limited financial support for one or more advanced modular reactors [REF 31]. In 2019 the Government announced limited support for a team led by Rolls Royce to develop a medium-size pressurised water reactor (PWR) for possible UK deployment. However, although the UK has shown interest in smaller reactors, progress has been slow and Government commitment has at times been ambivalent. By contrast, US and Chinese funding sources for SMRs are significant.

The options for SMRs, based either on scaled-down and integrated PWR technology, or on so-called 'advanced technologies', present a range of alternatives to large-scale nuclear. Such alternatives could be used not just for electricity generation, but also for heat use and energy storage.

With the right support, appropriate licensing and public acceptance, SMR designs based on downscaled PWR technologies could be available by the early 2030s, with capability to supply both electricity and low-grade heat to district heating systems.

In addition, some developers of advanced, high-temperature SMRs are proposing integrated systems that directly couple their reactors to molten salt heat/energy storage tanks, which might better complement intermittent renewable generators. Molten salt energy storage is a proven technology already deployed with concentrated solar power stations.

High-Temperature Gas-Cooled Reactors (HTGRs) have the ability to provide the temperatures required by the majority of energy intensive industrial process heat applications. For processes requiring temperatures less than ~600°C, most elements of HTGR technology have already been proven in prototype reactors around the world. In the future, HTGRs could provide very high-temperature process heat (800-1000°C+); but further development is required, particularly in the area of high-temperature materials performance.

Finally, nuclear fusion continues to be a source of research and development both in the UK – via the UK Atomic Energy Authority (UKAEA) – and internationally.

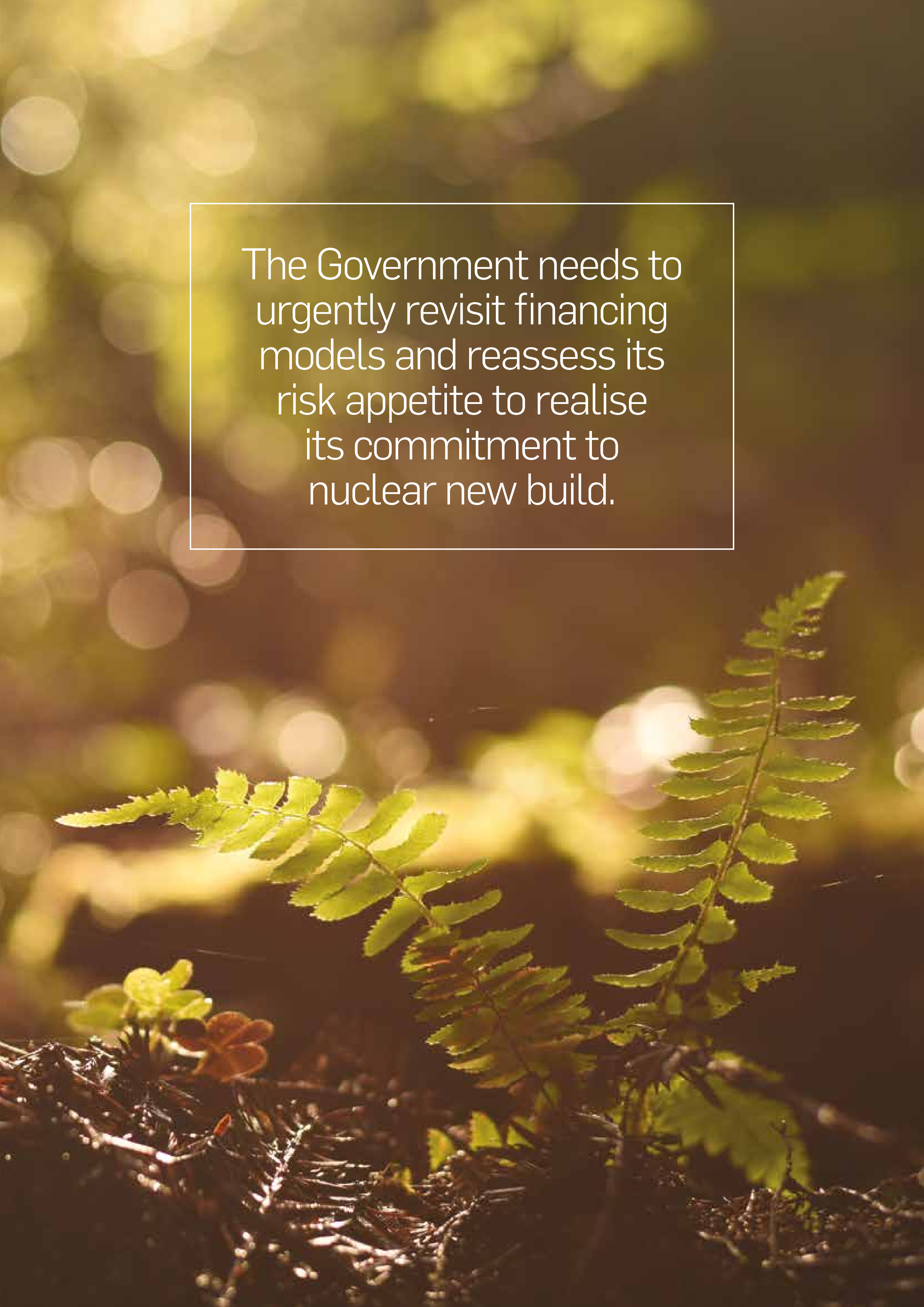
Thus, nuclear technology varies from well proven low technical risk for currently deployable PWR reactors to needing significant technical development for future reactors that may have wider application in the low carbon economy.

Can the technologies be deployed in sufficient quantity and at pace to achieve the target? How will they be financed?

The Rate of Nuclear New Build Deployment

The deployment rate of new nuclear in the UK has been shown to be slow, with Hinkley Point C only now moving into its major construction phase. For subsequent plants, it is unlikely that a project can move from initial permitting activity to commissioning in less than ten years. The rigorous licensing regime and the risks associated with affordability and construction have contributed significantly to the long project timescales between concept and commissioning. Net Zero assumes that units at Sizewell C and Bradwell B will be built ready to contribute to the low-carbon power generation mix in 2050.

The Government needs to urgently revisit financing models and reassess its risk appetite to realise its commitment to nuclear new build.

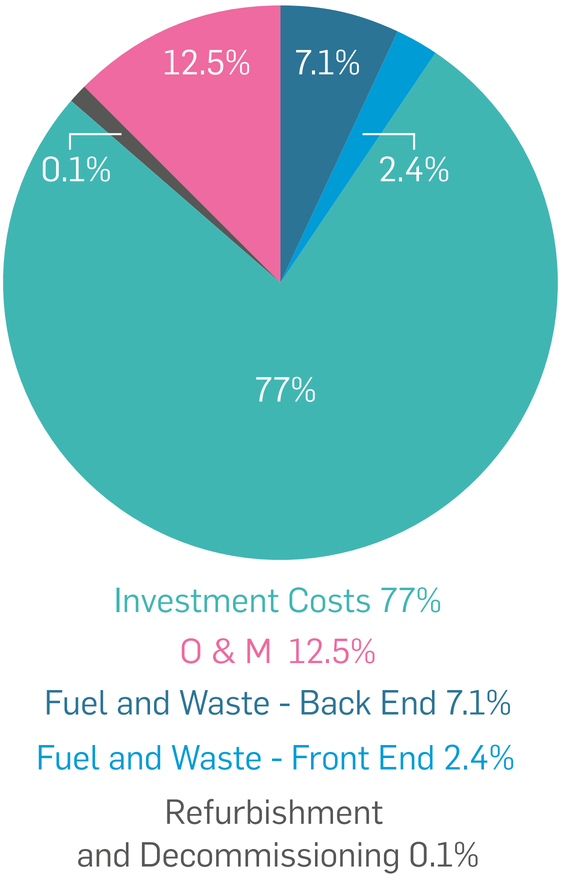


The withdrawal of Hitachi from the Wylfa project confirmed that the current UK model for financing such projects is not fit for purpose. Government has recognised this, but there is clearly a risk that even the limited ambition of Sizewell C and Bradwell B will not be realised.

The Cost of Finance

Regarding the deployment of large-scale Gen III/III+ LWR technology, the major challenge in the UK is the affordability of project capital investment. With reactors costing in the region of £7bn per unit, plus the long lead time before generation and return on investment, the cost of finance is critical to nuclear investment decisions. For example, it has been estimated that over 70% of the LCOE for large-scale nuclear is attributable to development costs, CAPEX and cost of capital, as shown in Figure 13.

Figure 13 – LCOE breakdown for large-scale nuclear in OECD countries [REF 5]



The current UK financial model has been shown to be unsuitable to bring forward investment in new nuclear plants. These issues are recognised by Government and a consultation on an alternative financial model, the Regulated Asset Base (RAB), was launched in July 2019 [REF 32]. Alternative financial structures which reduce the cost of finance could significantly reduce the LCOE for large nuclear plants. However, the LCOE of large nuclear is not the only impediment. Another major issue is the assumption of cost/completion risk during the construction phase.

Cost Reduction

In addition to developing a new financing model, there is much the industry can do to realise cost savings to support the viability of large-scale nuclear. The Nuclear Sector Deal sets out a target of a 30% reduction in cost within the UK new build programme by 2030. While initiatives in the engineering and construction supply chain will also drive down costs, we believe there are two key initiatives that warrant policy reconsideration:

- **Repetition**

  Nuclear new build projects are exceptionally complex endeavours. To obtain the efficiency gains found in other industries, they require repetitions whereby the same technology is built by the same organisation in, as far as possible, the same context. This approach helped to underpin the success of the French nuclear programme, where 50GW of capacity was connected to the grid in 10 years. However, such an initiative may appear to run counter to competition policy.

- **Nuclear Safety and ALARP**

  We would also recommend a review of how the ALARP principle, which underpins nuclear safety, is applied in the UK. The aim of continuously reducing risk is of course commendable and sound. However, we believe more needs to be done to avoid the ratcheting of costs (e.g. through additional analysis, supervision and inspections) when the solution is 'already safe to the highest standards'. While in other industries advances in technology have led to cost improvements, in nuclear they have led to cost increases. For example, now that computer analysis allows more detailed investigations, there is often a reluctance to accept engineering judgments. This results in the pursuit of incredibly small tolerances or defects simply because it is now possible to do so.

  It is important to stress that we do not fundamentally challenge the current regime and its philosophy.

However, we are concerned over the way it is increasingly being applied in the industry, leading to the redesign of demonstrably safe systems (in some cases already operating in other countries) and the development of more complex and expensive solutions.

Tackling this trend would require a coordinated programme of behavioural analysis involving the Office for Nuclear Regulation (ONR), present and future licensees and critical suppliers. It would need to comprise the production of guidance documents and training, with a formal oversight to ensure that cost improvements are being made without having a detrimental impact on safety performance. Conversely, it would need to ensure that safety enhancements are not being demanded by regulators or offered by vendors without due regard to cost.

What are the principal risks, both technical and commercial, that could derail efforts to achieve the target?

Risks

Project Affordability and Competitiveness

Given the significant capital cost of new nuclear, unless a site developer is state owned it is unlikely to be able to rely on its own balance sheet for funding. Therefore, the cost of capital is a significant risk to the affordability of the programme. As noted above, alternative Government financing models (including access to low-cost capital) could mitigate this risk.

It has been stated publicly that the proposed strike price for Wylfa was agreed at around £75/MWh, which is a significant decrease from Hinkley Point C's £92.50/MWh. However, government did not feel that the overall package for Wylfa was competitive with other sources of generation, offshore wind being frequently quoted as increasingly offering the least cost generation.

Erroneous Competitiveness Analyses/Market Intervention

Much attention has been directed to the strike price of Hinkley Point C, and more generally to the LCOE competitiveness of new nuclear. Currently there is a widely held view that nuclear is not competitive with other forms of low-carbon generation. When system-wide costs are included, it is clear that the true cost of integration of intermittent renewables is considerably more than the apparent LCOE. The encouragement of renewables with effective priority in call-off ranking and 'take or pay' contracts has an impact on prices for other generators, including nuclear. There is therefore a real risk that the long-term availability of nuclear, which may be essential to sustain Net Zero, could be compromised by misleading cost comparisons and market interventions designed to introduce other technologies. The Net Zero scenario demonstrates this risk, it effectively shuts down new nuclear build after the mid 2030s.

New Build Construction Risk

As with all major capital programmes, new nuclear has significant risk associated with construction overruns, which can have a major impact on programme costs and revenue. An appraisal of how this risk can be mitigated (through Government guarantees or other methods) should be explored further, particularly in the context of the RAB model.

The Rate of Nuclear New Build Deployment

The slow rate of deployment of large nuclear plants is a clear disadvantage, posing a risk to the contribution nuclear can make to the Net Zero target. The introduction of smaller plants (such as SMRs) could help to accelerate deployment, but under the current licensing regime SMRs bear a disproportionate regulatory burden, which would in turn also impact timelines.

Opportunities

Nuclear and CCGT with CCS are the only available low-carbon 'firm' generating options. In the long term, looking to the ultimate scenario described in our 'Road to Decarbonisation' paper [REF 1], CCGT running on natural gas will become unattractive due to limited gas availability. Thus, nuclear is the only currently available technology that offers long term firm low carbon generation.

The UK has extensive nuclear capability developed over the past 70 years but does not have an indigenous large reactor design. The UK is now a purchaser of foreign nuclear technology. Nevertheless, in the near-term the UK has nuclear export opportunities in the areas of:

- technical services
- legal and commercial services
- specialist components
- waste management and decommissioning services

Small modular reactors, particularly Gen IV reactors, could offer a potential route for the UK to exploit its diverse technical capabilities and position for export opportunities in the international nuclear market. Such a strategic decision would require government involvement and co-ordinated participation from the UK's dispersed technical capabilities. Government's initiative to select an SMR for UK deployment was abandoned and has been replaced by an inadequately funded Advanced Reactor initiative which currently lacks direction. Meanwhile Gen IV research is moving ahead in China and is attracting increasing funding in the US.

In summary, the UK is exploiting its extensive nuclear technical capabilities and reputation in export markets but to realise the full potential of the industry in global nuclear fission markets will require an adequately funded national strategic initiative focussed on developing a competitive domestic and internationally deployable reactor. Others are already ahead of us in this race. Curtailment of UK nuclear new build in the mid 2030s will effectively accelerate the decline of UK nuclear fission capability, foreclosing on potential global opportunities.

The UK's singular world leading nuclear capability is the Fusion research lead by UKAEA at Culham, which offers a long-term opportunity to sustain and build a global market lead for the UK. Government's recent announcements of funding for the STEP reactor and infrastructure at Culham are a most welcome recognition of the potential opportunities in this area.

2.3.3. Hydrogen

There have been many reports on the potential roles of hydrogen in the low-carbon economy, including an extensive CCC report published in November 2008 [REF 33]. Net Zero [REF 3] builds on this work and anticipates the use of 270 TWh of energy from hydrogen. However, the eventual extent of hydrogen's contribution is unclear, with many potential uses and uncertainties regarding costs and other constraints.

In the Net Zero Further Ambition scenario, hydrogen production is substantially based on advanced MR and CCS at large centralised plants, with hydrogen being distributed via gas networks. There is a smaller role for production using electrolysis, which may be more widely distributed:

- Producing 225 TWh of hydrogen via advanced gas-reforming could require up to 30GW of hydrogen production capacity, equivalent to 30-60 typically sized hydrogen production plants
- Producing 44 TWh of hydrogen via electrolysis could require between 2-7GW of electrolysers, depending on the load factors of the plant. Electrolysers are much smaller, modular technologies up to around 10MW in scale. This implies 200-700 electrolyser units, although groups of units could be co-located.

What are the technologies that need to be engineered and deployed to meet the Net Zero target?

Hydrogen requires the deployment of specific technologies relating to production, transport, distribution and storage. Although these technologies are currently well understood in an industrial context, there are significant issues to be evaluated in terms of the wider use of hydrogen envisaged by Net Zero.

In an interconnected hydrogen system, we will need to deliver large volumes of natural gas; convert it to hydrogen (where MR is envisaged); transport the CO_2 for sequestration; and either store or transport the converted hydrogen. We will also need to understand the optimum arrangement for this network.

While the UK has an established gas network, we do not currently have a CO_2 network. Such a network will need to be developed based on proximity to emitters and offshore stores. We also do not currently transport hydrogen in high pressure pipelines and only have limited existing storage, albeit with capacity for a lot more in the future.

Are these technologies well established and proven? If not, what technology development is required?

Production

The UK currently produces around 0.7Mt of hydrogen annually (27TWh), the majority of which is produced via either steam MR or partial oil oxidation across 15 sites. The hydrogen produced is used in the manufacture of two of the most important industrially made chemical compounds: ammonia and methanol. It is also used in the refining of oil; for example, it is key to reforming (one of the processes for obtaining high-grade petrol) and removing sulphur compounds from petroleum.

These hydrogen production methods are well proven but result in CO_2 emissions, which is unacceptable in the Net Zero scenario. CCS will therefore be essential. Based on our notes in the following section on CCS, we conclude that the dependency on CCS requires close attention and development.

Smaller quantities of hydrogen are currently produced by electrolysis. This technology is also well established, although there are a number of variants and active developments to reduce the cost of hydrogen from electrochemical methods.

At very high temperatures (>700ºC), thermochemical processes may be used to generate hydrogen. These processes are in early development and related to HTGR potential. As such, they are unlikely to make a significant impact before 2050.

The Net Zero scenario assumes the use of MR with CCS as the primary method of hydrogen production, as currently this is the least cost production method (Table 3 shows CCC's assumed costs of hydrogen production). The range of production costs are wide and vary significantly from the MR with CCS methods (£39-44/MWh) to electrolysis (£89-90/MWh).

Although the simple production cost comparison above points strongly to MR with CCS, this is only part of the whole system cost of delivering hydrogen-based energy. In common with intermittent renewable generation sources, the production cost (LCOE for power) alone does not provide a suitable basis for system design. In the case of hydrogen, many applications involve energy conversion and at each stage there are losses. Storage and transportation may also add significant cost.

In the case of domestic heating, where Net Zero anticipates extensive use of hybrid heat pumps, there is a requirement for hydrogen to supplement the heat pumps during particularly cold periods. This demand is infrequent, however, meaning that infrastructure costs to deliver the hydrogen are likely to be disproportionately high.

Optimal system design requires detailed analysis of the potential round-trip efficiencies and costs of hydrogen. Some of the conversion and system losses identified by CCC and others are illustrated in Figure 14. Taking typical electrolyser efficiency, the use of hydrogen in a domestic boiler might be around 60% efficient. In a fuel cell-powered vehicle this figure might be 40%, but falls to 25% when the hydrogen is converted back to electricity in a gas turbine. The use of hydrogen for peaking power requires assessment based on specific locations and the alternatives available in those locations (for example, co-locating with renewables could be attractive where curtailment is a frequent issue).

Figure 14 – Hydrogen Conversion Losses

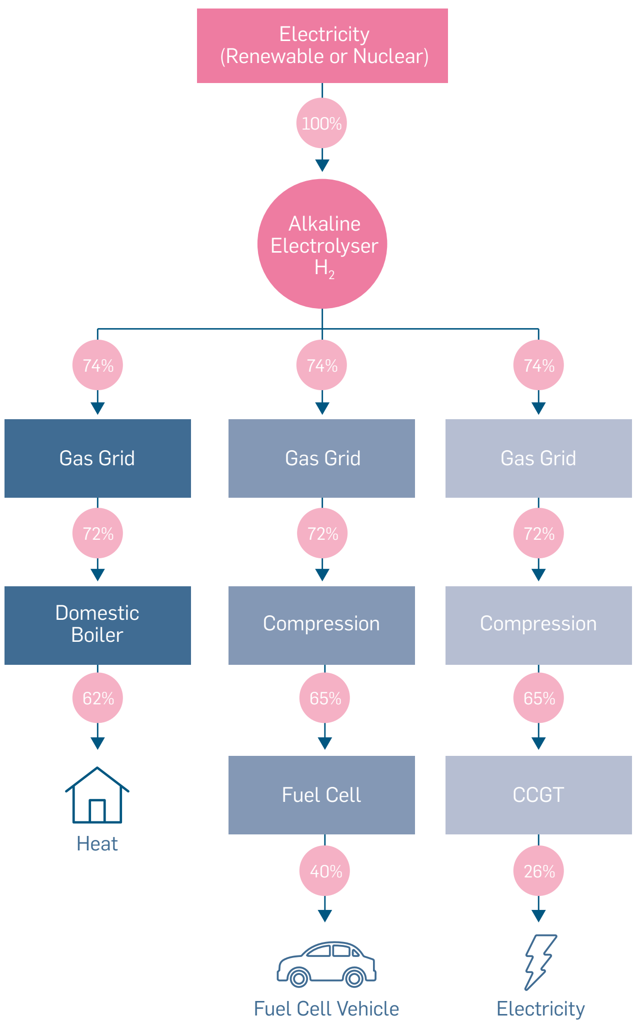


Table 3 – Costs of Hydrogen Production [REF 33]

	Current global supply (TWh)	Key inputs	Efficiency estimates (%)		Cost estimates (£/MWh H_2)		CO_2 intensity (gCO_2/kWh)	CCS required	Other considerations
			Current	Future	2025	2040			
Gas reforming									
Steam methane reforming +CCS	965	Natural gas	65%	74%	£44/MWh (£32-50/MWh)	£45/MWh (£34-57/MWh)	45-120	Yes	Exposure to natural gas price.
Advanced gas reforming +CCS	N/A	Natural gas, oxygen	N/A	81%	£39/MWh (£28-45/MWh)	£44/MWh (£27-46/MWh)	29-99	Yes	Exposure to natural gas price.
Electrolysis									
Proton exchange membrane electrolyses	<1	Low-carbon electricity, water	67%	74-81%	£89/MWh	£73/MWh (£48-80/MWh)	0-325	No	Water use / desalination.
Alkaline electrolysis	79	Low-carbon electricity, water	67%	74-81%	£92/MWh	£77/MWh (£52-84/MWh)	0-325	No	Water use / desalination.
Solid oxied electrolyser	N/A	Low-carbon electricity, water, low-carbon heat	N/A	92%	£90/MWh	£72/MWh (£54-79/MWh)	0-288	No	Water use and vailability of low-carbon waste heat.
Gasification									
Coal gasification +CCS	355	Coal	54%	54%	£68/MWh	£61/MWh (£53-72/MWh)	112-186	Yes	Land footprint
Biomass gasification +CCS	N/A	Sustainable Biomass	N/A	46-60%	£106/MWh	£93/MWh (£64-127/MWh)	Potential to achieve negative emissions	Yes	Sustainable supply of biomass feed stock.

As seen, the Net Zero scenario includes significant hydrogen use which is dependent on MR with CCS. The pursuit of lower cost hydrogen production by electrochemical or thermochemical processes should therefore be a high priority. The efficient application of hydrogen is also critical and dependent on system architecture.

Transportation and Distribution

Hydrogen generation by MR is likely to be centred on large sites which are either close to major industrial end-users or close to natural gas import locations.

It is assumed that an entirely new high-pressure transmission pipeline would be built to transport hydrogen to local distribution networks. It is further assumed (based on the Leeds H21 analysis) that the existing natural gas system would be converted to deliver low-pressure hydrogen distribution. In a report for BEIS, the total base case cost breakdown for the entire gas distribution network is estimated to be upwards of £22bn [REF 9].

Several initiatives have been set up to work on viable solutions for hydrogen distribution, and to help inform Government policy. As part of these efforts, it is likely we will see the safety case demonstrated and approved for an increasing hydrogen blend in the distribution network. It is also likely that the hydrogen transmission pipelines would follow similar routes to the natural gas network, as the connection/breakout points would remain the same. The pipeline would also be largely subterranean.

If full conversion were to take place, the existing gas transmission network would still be used in part to supply industries which rely on methane as a chemical feedstock; plants using methane to produce hydrogen; and electricity generation plants utilising CCS. Sections no longer required for natural gas could possibly be repurposed to provide better resilience and/or improve 'linepack'.

Assessing the available options to use the existing gas transmission and distribution systems is an urgent priority. Such an assessment will be critical to understanding the potential use of hydrogen in the Net Zero scenario.

Storage

Currently, gas storage in the UK mostly takes the form of linepack (intra-day) and subsurface (intra-season) storage. There are also some above-ground facilities. Across terminals, linepack and salt caverns, our current gas storage capacity amounts to about 2.5bn m^3.

Of the options available, subsurface storage is the most cost-effective for large volumes of gas. The two principal benefits of centralised, bulk subsurface storage are:

- The ability to manage short, medium- and longer-term variance in supply and demand requirements
- The provision of insurance in emergency scenarios (e.g. failures in the supply chain, extreme weather events)

Existing subsurface storage is relatively limited in the UK, where historically, due to the availability of North Sea gas, scaling up storage capacity was never a priority. In addition, more recently the commercial gas market environment has restricted gas storage development.

However, in a hydrogen system, storage demands would be likely to increase. Firstly, there would be a limited number of bulk sources (at least initially). Secondly, we would still have to manage seasonal energy demand, with the optimum point of production somewhere between peak winter and low summer. The only viable buffer would be additional storage capacity.

Subsurface storage includes both salt cavern storage and depleted oil and gas reservoirs. In the UK, there are several regions of salt cavern storage (Teesside, East Yorkshire, Cheshire, NE Ireland and the Wessex/Somerset basin), shown in Figure 15. While all of these regions have the potential for additional salt cavern capacity, Cheshire and East Yorkshire are the most promising, with several operators already managing commercial gas storage sites in these areas.

The selection of a suitable storage site is complex and depends on many factors, such as:

- The quality of geology and its ability to be operated with integrity
- Depth of store (the depth varies at each location, which drives overall pressure constraints and therefore useful storage volumes)
- Faults and folds
- The potential density of salt caverns or the porosity and permeability of reservoirs
- Surface restrictions (e.g. proximity to populated areas)
- Areas of natural beauty/protection
- Proximity to industry (for pipeline transport)

Due to their inherent flexibility and integrity, it is likely that salt caverns will play a major role in any future hydrogen storage system. Atkins has completed extensive research in this area.

However, Net Zero considers only a limited role for hydrogen in the decarbonisation of heat, and it appears that subsurface storage was not included in Net Zero modelling scenarios (only 50TWh of storage appears to have been included). Large-scale conversion of natural gas to hydrogen for domestic heating will require firm Government commitment and the development of subsurface storage on a much greater scale.

Figure 15 – Distribution of the main halite bearing basins in the UK and the location of operational and proposed underground gas storage sites [REF 34]

Can the technologies be deployed in sufficient quantity and at pace to achieve the target? How will they be financed?

The current uncertainties around the potential for hydrogen use are a significant impediment to deployment. Net Zero envisages a ten-fold increase in hydrogen production and notes: "Supply and demand must be joined up, with strong coordination and integration of supporting policy and regulatory networks and a strong Government direction and leadership in infrastructure development." [p.64 REF 4]

As to the scale of plant construction required, we can refer to work by the International Energy Agency (IEA) [REF 35]. Here, the IEA modelled a steam MR plant with an hourly hydrogen production rate of 100,000Nm3/h and varying CO_2 capture technologies. Net Zero would require 69 such plants to meet anticipated production volumes.

The estimated capex for such a plant is between EURO170m and 305m, depending on the technology used. Taking £250m as an indicative capital cost, and assuming the 69 plants were constructed over a 20-year period, this would imply a workload of around £850m a year. Both the hydrogen production plants and the CCS plants needed under Net Zero would therefore impose a major workload on the process engineering industry; we consider this workload in the following section on CCS.

What are the principal risks, both technical and commercial, that could derail efforts to achieve the target?

Risks

Currently, there is an assumption that MR is the major basis for hydrogen production. This requires the successful deployment of CCS which, as discussed in detail in the next section, is a risk in terms of commercial viability. To mitigate this risk, we consider a drive in R&D towards production of hydrogen from non-MR sources to be a major priority.

Another risk involves low round trip efficiencies, which drive up costs. To minimise these losses, careful planning will be required to ensure that inefficient uses are avoided and production sources are located close to the point of use (particularly relevant in industrial contexts).

The complex interfaces of a hydrogen economy are also technically challenging, with the potential to result in a disjointed or (worse) redundant system. Furthermore, each interface represents a potential commercial transaction and risk. Without a clear hydrogen strategy backed by Government policy and commitment, there is a risk that the hydrogen economy will simply not develop. To counter this risk, the use of hydrogen in all the applications discussed requires the overarching energy system architecture to coordinate the sub-system components.

Opportunities

Based on the potential for hydrogen cogeneration during surplus renewable power output, and the use of waste heat from nuclear to enhance electrolyser efficiency, we recommend that the Nuclear Industry Association (NIA) and the Offshore Wind Industry Council (OWIC) collaborate to develop efficient hydrogen technology programmes. Such programmes could help to address issues relating to exploitation of waste heat and variability of power generation, thereby de-risking hydrogen generation from CCS.

System Integration of Hydrogen

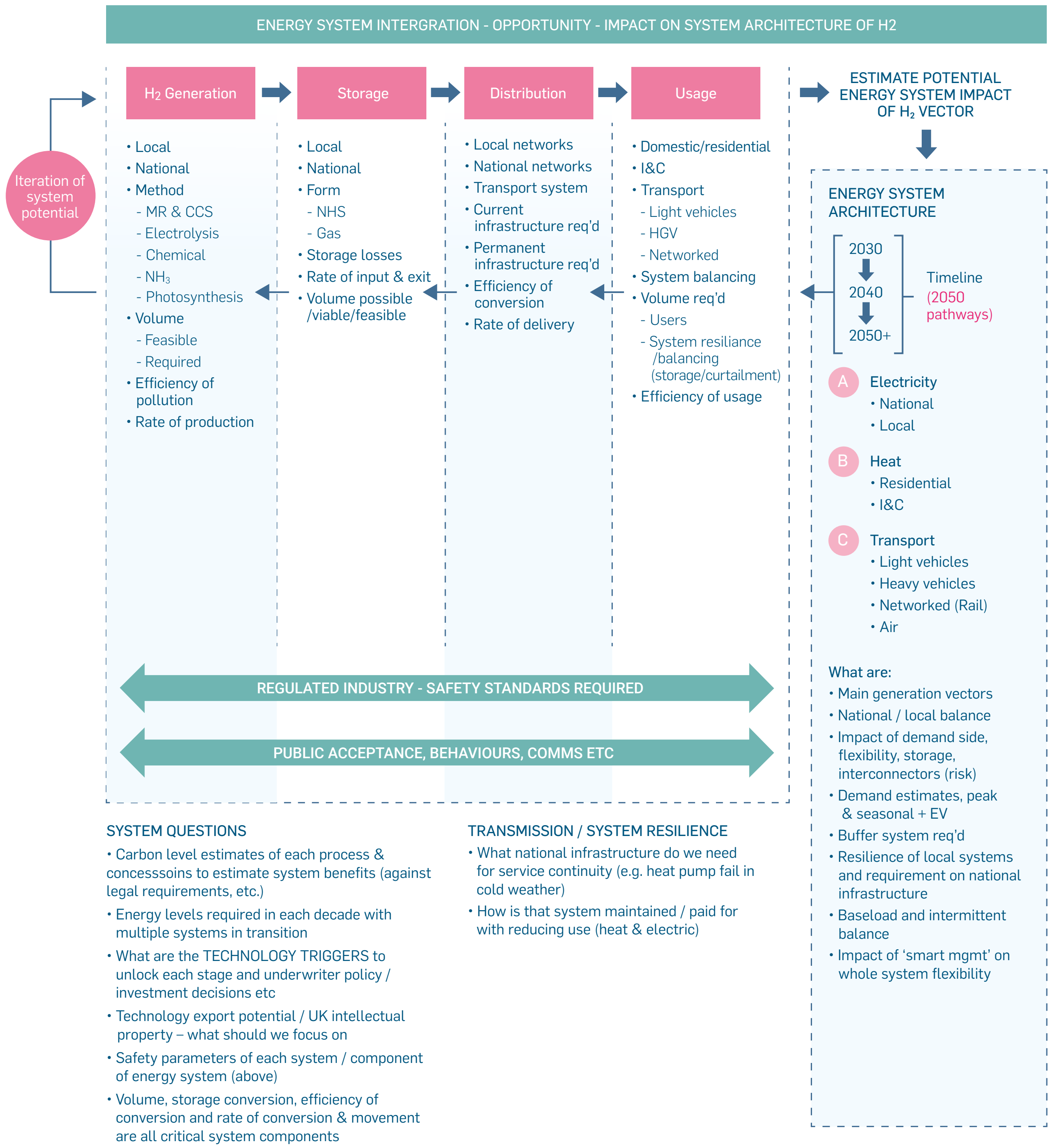
It is recognised that full system integration has been achieved for the natural gas network (where we have key network components in place, such as production, storage, distribution, regulation, usage and international trading). However, perhaps out of all of the Net Zero components, hydrogen presents the greatest challenge around integration into a future energy system.

Considering this system, key questions arise relating to hydrogen's role. These include: where and how will we produce hydrogen? How much will be produced in each location? How much storage will be required for system balancing? And what does the hydrogen transportation network need to achieve?

The overall configuration of the system requires a detailed, long-term plan to avoid abortive investment. Different needs will have to be met across the UK, and solutions in one region may not be valid in others. For example, industrial areas would be more likely to support MR, whereas densely populated areas may be more inclined towards electrolysis technology.

The concept of the ESA has been raised already, and this is discussed in more detail later in this paper. Taking hydrogen as an example of how a complex sub-system could be configured and managed, we have mapped the integration journey in Figure 16:

Figure 16 – Energy System Integration – Opportunity and Impact on System Architecture of Hydrogen



2.3.4. Carbon Capture and Storage

Carbon Capture and Storage (CCS) is central to the Net Zero scenario for the UK, where several 'clusters' of CCS capability are envisaged and the capture rate of CO_2 will be 176Mt/yr, whereas today our capacity is zero. Our analysis shows that in 2050 approximately 40% of our energy will be dependent on CCS, we see development of CCS as the biggest single risk to the Net Zero scenario.

Proposers of CCS point out that it is a proven technology, which is the case. However, current global capacity is approximately 40Mt/yr, most of which is spread across 18 projects, the majority of which utilise CO_2 from a single source for the purposes of enhanced oil recovery (see Figure 18). The Net Zero scenario envisages that the UK alone will capture and store more than four times the current global capacity, from diverse sources and not always with the economic benefit of enhanced oil recovery.

There are significant technical issues to be overcome and very complex commercial issues to be solved. To date progress in the UK has been slow. There is a serious misalignment between government policy and action and the scenario described by CCC.

What are the technologies that need to be engineered and deployed to meet the Net Zero target?

CCS can be used to decarbonise multiple sectors, including power generation, heavy industry, heat, transportation and waste, and to remove CO_2 directly from the atmosphere. A number of industrial processes produce high concentration CO_2 waste streams, permitting cost effective capture. These offer 'low hanging fruit' and should be prioritised.

The technologies required for CCS can be broken down into three segments: CO_2 capture, transportation and storage. Here we look at each segment in turn.

CO_2 Capture

There are currently three primary methods of CO_2 capture: post-combustion, pre-combustion and oxy fuel combustion. Post-combustion involves scrubbing the CO_2 from flue gases released during the combustion process. Pre-combustion uses a gasification (solid fuel) or reforming (gaseous fuel) process, followed by CO_2 separation to yield a hydrogen-rich fuel gas. Oxy fuel combustion involves combusting fuel in recycled flue gas enriched with oxygen to produce a CO_2-rich gas. These processes are shown schematically in Figure 17. The range of large-scale CCUS facilities in operation or under construction today is shown in Figure 18, which clearly shows that the vast majority are for enhanced oil recovery and none are over 10Mt/yr.

CO_2 capture processes have been used in heavy industry and the oil and gas sector for decades. For example, the amine process (likely to be favoured on power plants using post-combustion capture) is typically used to remove CO_2 from natural gas prior to transportation.

The selection of a CO_2 capture process will depend on the source characteristics, the existing infrastructure at the source site and the economics for the site concerned. Capture processes vary from well proven with decades of experience to developmental. Given the potential importance of CCS to the creation of a low carbon economy, we expect significant process development in future.

The UK's concept of a number of 'clusters' combining the CO_2 from multiple and varied sources implies that multiple carbon capture technologies will be employed, presumably selected in each case by the source owner and operated to serve his needs. We envisage that the cluster infrastructure operator will need to specify an envelope of quality and conditions of the CO_2 for acceptance into the system.

Figure 17 – Alternative CO_2 Capture Processes from Figure 3.1 [REF 36]

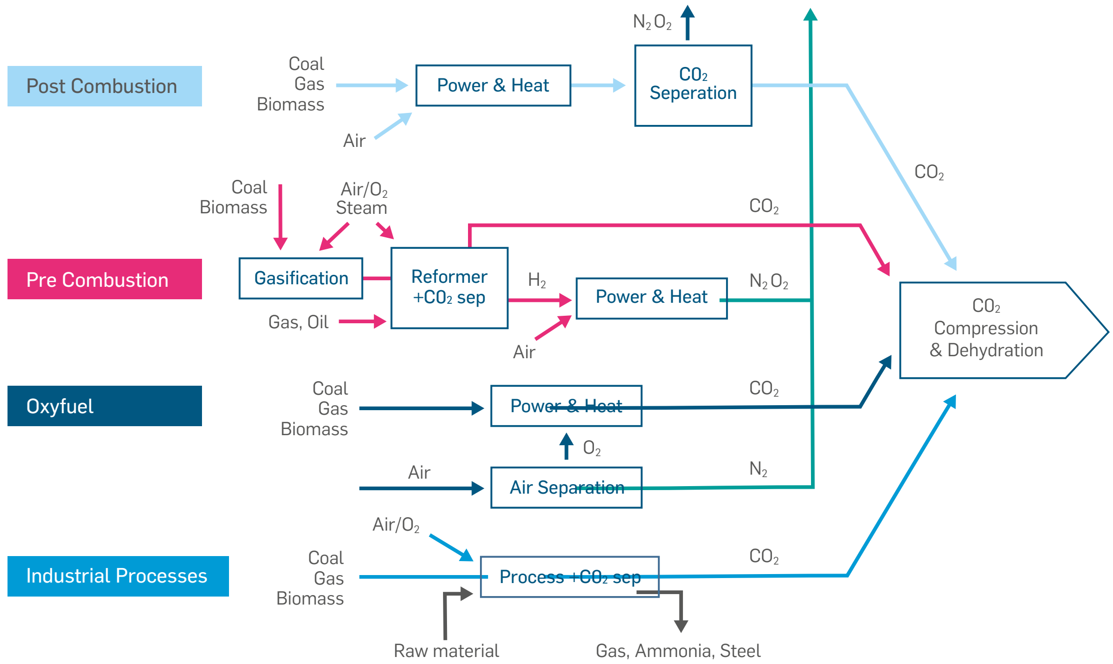
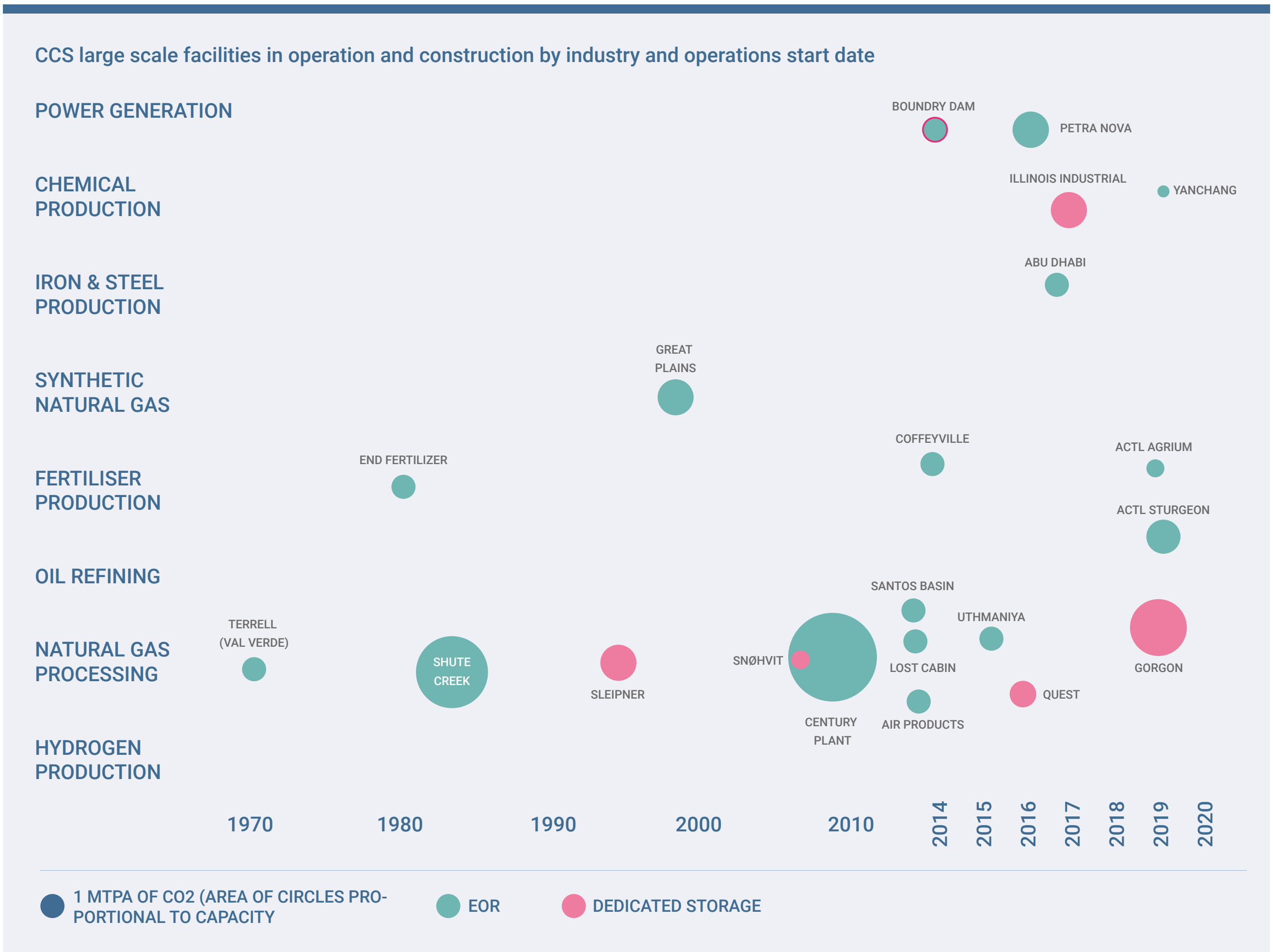


Figure 18 – Existing CCS Projects [REF 37]



CO_2 Transport

The technological aspects of CO_2 transport are well understood. Compression, buffer storage and pipeline transport are all established technologies, while CO_2 transport via pipeline is a straightforward application.

The transport of CO_2 via pipeline has been utilised for over 30 years in the US and Canada, where there is a 6,200km network of high-pressure CO_2 pipelines. The UK has existing onshore and offshore infrastructure such as Goldeneye and Feeder 10 pipelines; these are each proven to be suitable for CO_2 transport.

Transport of CO_2 via ship is also a viable option for countries such as Norway and Germany. Several studies have been undertaken on transporting CO_2 via mainland Europe to a receiving port in Peterhead or Hound Point in the UK.

However, a major impediment to establishing clusters for CCS development is the financing and contractual framework for the transport infrastructure. This has been extensively reviewed and is discussed further in the report.

CO_2 Storage

CO_2 can be permanently stored deep underground in geological formations. In the UK, the geological formations are located offshore in either saline formations or in depleted oil and gas reservoirs. An ETI-funded project [REF 18] identified 20 specific CO_2 storage sites, which together represent the tip of a very large strategic national CO_2 storage resource, estimated to be around 78GT (78,000 million tonnes). The top 15% of this potential storage capacity would last the UK around 100 years, with sufficient capacity for 2050 CO_2 projections. In terms of storage there is effectively no technical limit on our capacity.

As noted above, most existing large-scale CCS projects use the captured CO_2 for enhanced oil recovery (EOR) operations. In the UK, EOR has not been widely developed as the CO_2 storage sites are located offshore which makes EOR significantly more expensive due to the number of wells required.

In terms of offshore infrastructure, early CCS projects are likely to use fixed offshore facilities. In some cases, the infrastructure may comprise existing facilities, as with the Goldeneye facility proposed for the Peterhead CCS project.

This has the advantage of enabling developers to delay the decommissioning of existing North Sea oil and gas infrastructure (this includes an offshore platform and pipeline). However, the potential to use existing infrastructure will only exist if CCS projects can be brought forward before the infrastructure reaches end of life or is decommissioned. Furthermore, the creation of CCS clusters that are dependent on the use of ageing offshore infrastructure will require thorough due diligence on the condition and prospective life extension of these assets.

Are these technologies well established and proven? If not, what technology development is needed?

There are proven CCS technologies with the capability to decarbonise the power generation, industry and hydrogen production sources envisaged in the Net Zero scenario. There are also processes in development that may offer improved performance or economics. These are summarised in Figure 19.

Although some CCS processes are proven, these are mostly operating in a more 'steady state' mode and are not required to operate intermittently with fast start-up. Therefore, for the CCS clusters envisaged in the UK, we would focus on the specific technical implications of multi-sourced systems with the potential for large sources of CO_2 operating on an intermittent basis, as would be the case for CCGTs operating in the anticipated renewables dominated market. For example:

- Turn down amine plants to enable greater flexibility.
- Amine plants take a long time to restart; consider alternatives such as using steam to maintain temperature and/or storage of rich amine.
- Injection well design for low and variable CO_2 flow rates.
- Optimising the process and heat integration to reduce CCS energy penalties.

Can the technologies be deployed in sufficient quantity and at pace to achieve the target? How will they be financed?

The Net Zero system breaks down CO_2 sources for CCS as shown in Table 4, we have estimated how many plants / CCS trains this could require for each source category.

Figure 19 – Development Levels of CCS Technologies [REF 38]

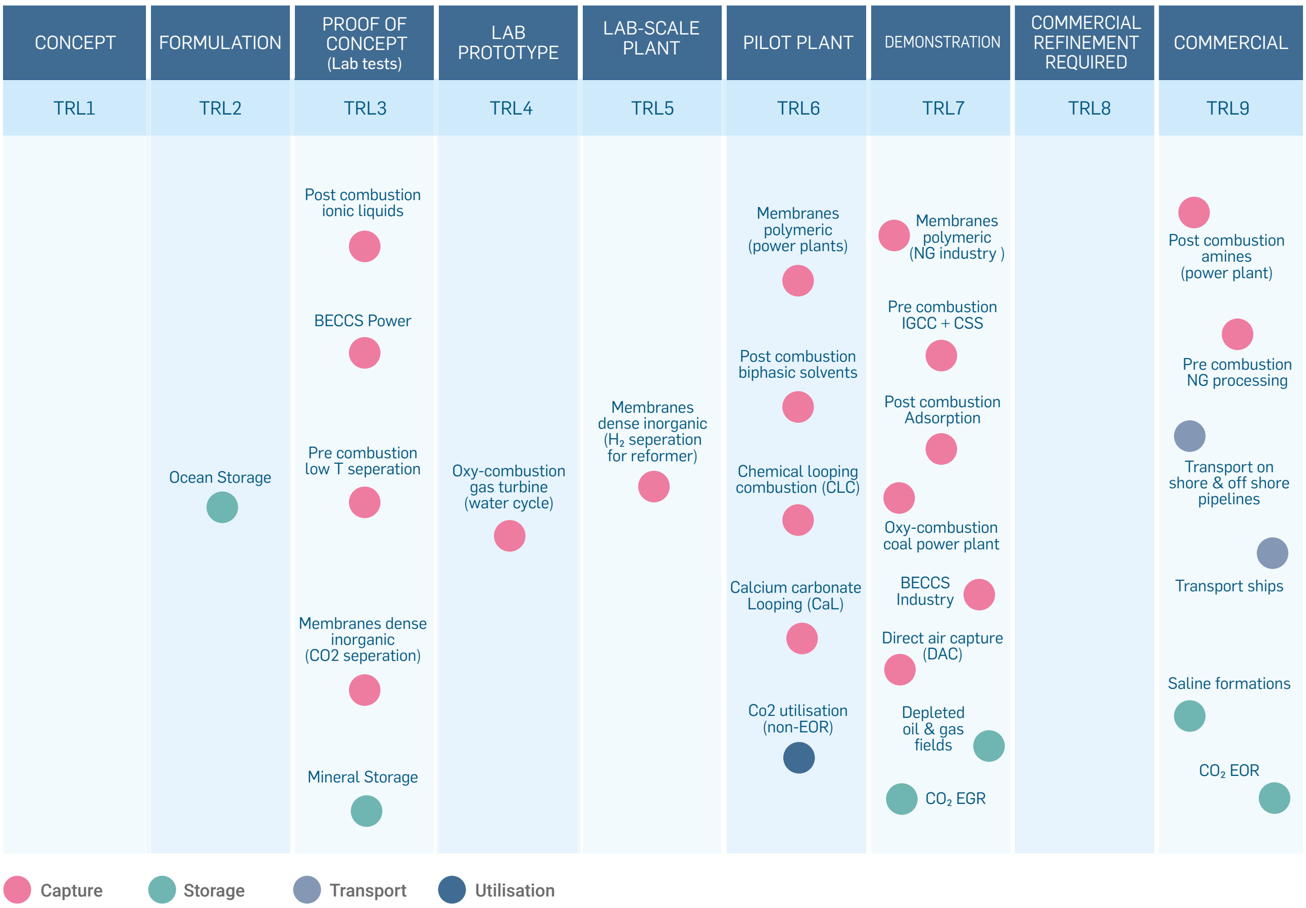


Table 4 – Equivalent number of plant and CCS trains for the Net Zero CO_2 sources

	CO_2 Capture Mt/yr	Equivalent No. of Plant/Train
Fossil Power Generation CCS (presumed to be Natural Gas	57	16/64*
H_2 Production	46	69/69**
BECCS	35	8-16/40***
Industry	24	TBC
Biofuel Production	9	TBC

** see Thermal Power with CCS detail below*
*** see hydrogen with CCS text below*
**** Net Zero assumes 5GW BECCS, 8 to 16 equivalent plants is based on a plant capacity range of 600MW (slightly less than the Drax units) down to 300MW. Note that the largest BECCS demonstrator under construction at present is in Japan, for a 50MW 180,000tCO_2/yr capture capacity. The number of plants is clearly sensitive to the average capacity assumed, and there could easily be an increase in the number of plants required.*

Thermal Power with CCS

The SNC-Lavalin group co-authored the ETI Thermal Power with CCS report, where techno-economic aspects were considered for a range of potential CCGTs with CCS based on a 'standard' train of 600MWe output. Such a train with 90% carbon capture and operating at 100% availability would produce 1.9Mt/yr of CO_2. Thus, to capture 57Mt/yr as envisaged by Net Zero would require approximately 30 trains or 18GW of CCGT operating at 100% load factor. However, the market is clearly envisaged to have the CCGTs operating well below 100% load factor. We have previously (Section 1.1.1) estimated that Net Zero requires CCGT with CCS installed capacity of 40GW, which implies a load factor across the CCGT fleet of approximately 50% to produce the anticipated 57Mt/yr of CO_2.

Therefore, we assume that approximately 16 large (4 train 2400MW output) plants will be required to be built between 2030 and 2050. These plants, if fitted with one CCS plant per train will require 64 large CCS plants.

Hydrogen with CCS

As a basis for the estimated 69 plant requirement for hydrogen production with CCS, we have used values from the [REF 35]. Here, the CCS system is assumed to be 90% efficient, with an hourly hydrogen production rate of 100,000Nm3/h, and a load factor of 95% for an established plant.

The IEAGHG report makes the following observation:

"The capture of CO_2 from a methane reforming plant is not new technology. This has been done in various plants worldwide. The capture of CO_2 from the syngas of the SMR is commercially deployed. The current state of the art is based on chemical absorption technology. However, what is new is the integration of capture technologies with CO_2 transport and storage. Additionally, new and novel CO_2 capture technologies are also being developed and demonstrated."

BECCS

Of the BECCS plants currently in operation globally (under 20 in total), most of them are linked to ethanol production, with currently very few power generation projects. In fact, Drax's BECCS demonstrator is one of only two power generation projects. Table 5 lists global BECCS facilities.

In the context of the broader Net Zero challenge, the production of liquid fuels (for example for use in aviation) may indeed be a better use of biomass than burning it to produce electricity.

CCS and Hydrogen Industrial Capacity and Capability

Having estimated the possible number of plants and trains of CCS that would be required across the power and hydrogen sectors, we can assess the potential for deployment by 2050.

On the basis that there could be approximately 100 plants with 160 CCS trains required to be constructed, and assuming that demonstrator plants are successfully deployed in the 2020s, up to five plants per year with eight trains of CCS would need to be constructed and commissioned between 2030 and 2050.

If each year five new plants were spread across different regions and industry types (hydrogen, biofuels and GT plus CCS in either pre- or post-combustion capture), this would distribute workload making the programme more achievable. Other key considerations include:

- The UK's civil engineering capacity is considered to be sufficient, as it is cross-industry
- The Engineering & Procurement and Project Management contracting market comprises >50,000 people, with a £3.5bn market mainly serving export. Again, this is considered sufficient to manage the projected deployment rates, although it is worth noting that some individual oil and gas projects can be very large, circa £10bn and over
- For Original Equipment Manufacturers (OEMs), there are at least three major industrial gas turbine suppliers, at least three major hydrogen technologies, and at least three major carbon capture technologies. In addition:
  - For CCGT and Biomass plants, there is a demand for 60+ turbines. OEM deliveries take around 18 to 24 months, so split evenly across the three OEM manufacturers this would mean 20 turbines per OEM, which is achievable. However, it is unlikely to be a sufficient throughput to prevent OEMs exploring alternative markets

Table 5 – Global BECCS Facilities [REF 44]

Name		Capture Source	Location	Scale	Status	Operation Year	Capacity Max (tpa)	Industry
Large Scale BECCS Facilities								
1	Illinois Industrial Carbon Capture and Storage	ADM com-to-ethanol plant	Decatur, Illinois, US	Large	Operating	2017	1,000,000	Ethanol Production
				Demonstration and Pilot	Completed	2011-2014	300,000	
2	Norway Full Chain CCS	Brevik (Norcem AS), Herøya (Yara Norge AS), Klemetsrud (Klemetsrudanlegget AS)	Norway	Large scale	Advanced development	2023-2024	800,000	Cement Production (>30% biomass), Waste-to-energy (50-60 biomass)
				CO_2 Capture Test Facility at Norcem Brevik Cement, Pilot	In evaluation	2013	Variable	
3	Occidental/White Energy	Hereford Plant and Plainview Bioenergy	Texas, US	In evaluation	In evaluation	TBC	600,000-700,000	Ethanol Production
Demonstration and Pilot Scale BECCS Facilities								
4	Russel CO_2 injection plant	ICM ethanol plant	Russel, Kansas, US	Demonstration and Pilot	Completed	2003-2005	7,700 tonnes (total)	Ethanol Production
5	Arkalon CO_2 Compression Facility	Arkalon BioEnergy ethanol plant	Liberal, Kansas, US	Demonstration and Pilot	Operational	2009	290,000	Ethanol Production
6	Bonanza BioEnergy CCUS EOR	Bonanze BioEnergy ethanol plant	Garden City, Kansas, US	Demonstration and Pilot	Operational	2012	100,000	Ethanol Production
7	Husky Energy Lashburn and Tangleflags CO_2 Injection in Heavy Oil Reservoirs Project	Lloydminster ethanol plant	Lloydminster, Saskatchewan, Canada	Demonstration and Pilot	Operational	2012	90,000	Ethanol Production
8	Mikawa Post Combustion Capture Demonstration Plant	Sigma Power Ariake Co. Ltd.'d Mikawa thermal power plant	Omuta City, Fukuoka Prefecture, Japan	Demonstration	Development Planning	2020	180,000	Power generation (coal and biomass)
				Pilot	Completed	2009	3,000	
9	Drax bioenergy carbon capture storage (BECCS) project	North Yorkshire power station	North Yorkshire, England	Pilot	Development Planning	2018	330	Power generation (coal and biomass)
10	CPER Artenay project	Artenay Sugar Refinery in the Loiret	Artenay, Orleans, Framce	Demonstration and Pilot	Development Planning	TBC	45,000	Ethanol Production
11	Biorecro/EERC project	Biomass gasification plant	North Dakota, USA	Demonstration and Pilot	Development Planning	TBC	1,000-5,000	Biomass Gasification
Notable BECCS Facilities								
12	OCAP	Abengoa's ethanol plant	Rotterdam, Netherland	Utilisation	Operational	2011	400,000 (100,000 from ethanol production)	Ethanol Production and Oil Refinery
13	Lantmännen Agroetanol purification facility	Lantmännen Agroetanol plant	Norrköping, Sweden	Utilisation	Operational	2015	200,000	Ethanol Production
14	Calgren Renewable Fuels CO_2 recovery plant	Calgren Renewable Fuels ethanol plant	California, US	Utilisation	Operational	2015	150,000	Ethanol Production
15	Alco Bio Fuel (ABF) bio-refinery CO_2 recovery plant	Alco Bio Fuel (ABF) bio-refinery	Ghent, Belgium	Utilisation	Operational	2016	100,000	Ethanol Production
16	Cargill wheat processing CO_2 purfification plant	Cargill wheat processing plant	Trafford Park, Manchester, UK	Utilisation	Operational	2016	100,000	Ethanol Production
17	Saga City Waste Incineration Plant	Saga municipal waste incineration plant	Saga City, Saga Prefecture, Japan	Utilisation	Operational	2016	3,000	Ethanol Production

- For hydrogen plants, split evenly between OEMs, the estimated 69 plants would result in around one plant per year for each OEM. Having recently reviewed throughput potential with a fabricator, we believe this can be delivered as the design of the plants would typically be repeat business
- For carbon capture OEMs, there is significant demand, possibly over 160 CCS trains of various sizes. The manufacture and deployment rate for CC technology is potentially a risk and supply chain capacity should be evaluated as soon as possible

› The peak human resource requirements for projects is circa 700 people per train. Therefore, total labour for each batch of five projects is approximately 3,500 people. Allowing for three years on site per project, that is a maximum of 10,500 people from the whole UK economy. We have assumed that conventional power and hydrocarbon projects will be ramping down, so it is likely that skills will be available to carry out this work, both on and offshore, for CCS. Capacity expectations are based on industry numbers; the oil and gas industry workforce in 2014 was 464,000, whereas estimates for 2018 are around 283,000 [REF 39].

The foregoing is a 'broad brush' assessment of supply chain capacity. We would recommend that, working with appropriate industry bodies, government undertakes a detailed supply chain assessment for all aspects of Net Zero delivery, starting with the hydrogen and CCS components.

Demonstration and commercialisation

While each of the component technologies across the CCS chain (capture, transport, storage) have relatively low individual technical risks, the integration and deployment timing of the CCS system is challenging.

Many respected advisors have been strongly recommending CCS for some years, but progress beyond FEED has been difficult to achieve. The current global rate of deployment is insufficient to drive cost reduction.

Where CCS clusters are envisaged, it is unrealistic to ask first-of-a-kind, single-system, point-to-point projects to deliver oversized CO_2 infrastructure that could eventually become part of a larger network. This means that early adopters (such as the cancelled Scottish Power Longannet CCS project and the Shell Peterhead project) would bear a cost that is disproportionate to their short-term value. As a result, CCS projects have been exceptionally difficult to initiate. Clustering from the outset with a collaborative approach between industry and Government will be necessary to deliver complex schemes and return better value overall.

Where the 'anchor tenant' or main user in a cluster is a power generator it is self-evident that the generator will not incur the additional cost of CCS unless and until the cost of CCS is less than the cost of emitting carbon or there is a CfD type scheme to pay for the additional costs and risks of CCS. Furthermore, where CCGT operators face uncertain load factors due to priority call off ranking for renewables this uncertainty only adds to the difficulty of investing in CCS.

The UK's attempts to launch demonstration projects sought to place performance risk on the project developers and contractors, with predictable results. Demonstration projects should be treated as such and should not be evaluated as 'production' projects.

The Net Zero scenario is dependent on implementation of CCS at an unprecedented scale. In the 2050 scenario as described, 28% of electricity generation (CCGT and BECCS) will require CCS. If we add hydrogen production to the equation, we see that 40% of the nation's energy will be dependent on CCS. To date, the UK has been unable to construct and commission a successful demonstration-scale CCS project. The current stated BEIS aim is "to have the option of deploying CCS in the 2030s subject to the cost coming down". This is counterintuitive, as without successive projects we cannot learn by doing. Such an approach will reduce opportunities to make improvements in construction strategy, process plant design and materials. It will also limit our chances of improving the efficiency of the carbon capture process. Cost reduction can be achieved, but it requires the experience that only comes from full-scale development and operations. Full scale demonstration projects in the 2020s will therefore be necessary to move this industry forward.

What are the principal risks, both technical and commercial, that could derail efforts to achieve the target?

Risks

Commercial framework

The commercial constraints on CCS have been thoroughly explored by various reports [REF 12, REF 15, REF 16, REF 40]. Only government can address these issues and it must do so as a matter of urgency. Where CCS clusters are envisaged, we anticipate that each source owner will invest in and operate his carbon capture plant. The transport infrastructure, comprising buffer storage, compression and pipelines will serve all sources in the cluster. Transport infrastructure is particularly difficult to finance since its revenue will depend on payment from each of the CO_2 sources. If one major source were to cease operations, then the infrastructure operator would be faced with a revenue shortfall or would have to increase charges to the remaining sources to compensate. The financial viability of the entire cluster is determined by the weakest source. This is only one of the commercial difficulties. Each and every source owner will have a commercial interface with the infrastructure operator. If the infrastructure fails for a period longer than buffer storage can accommodate then source owners will need to shut down operations. The potential for multiple consequential loss claims is obvious.

There are also concerns regarding liability for the long-term security of the CO_2 storage and for the short-term impacts of large sudden release from the transport system. It has been suggested that Government may need to own or underwrite both the transport infrastructure and the long-term storage liability.

It is unlikely that there can be a 'one size fits all' approach to the commercial difficulties, since each cluster will be unique.

Failure to deploy successful demonstrator site in the 2020s

If the UK is unable to successfully deploy a CCS demonstrator by the mid-2020s and build consensus and confidence around CCS as a route to decarbonisation, there is a risk that one of the central tenets of Net Zero will be undeliverable.

CCC and ETI believe that without CCS, the cost of meeting the UK's previous emission target of reducing emissions by 80% by 2050 against 1990 levels would almost double. However, to unlock the greatest opportunities for cost reduction requires deployment of CCS during the 2020s. If there are further delays in large-scale deployment of CCS the costs are likely to escalate. If this risk was realised, then there would need to be a shift from CCS-based generating sources (natural gas, MR for hydrogen), to non-carbon emitting sources (additional renewables, nuclear). There would be a subsequent investment then required in electrical networks to enable a higher level of electrification.

Full CCS chain integration and sub-system architecture

Developing the end-to-end CCS chain for multiple CCS producers (and from multiple emission sources) has not yet been demonstrated. The most significant risks to be managed will relate to the integration of the system in which diverse sources of CO_2 are captured by plants owned and operated by different commercial entities, buffered and transported by another entity and potentially stored by another entity. Hence, the integration, operating philosophy and control of such a system will be critical to the success of the overall project and the many commercial interfaces will need to facilitate overall system control.

Reliance on Existing Oil and Gas assets

CCS project developers hoping to repurpose existing oil and gas assets will need to carefully assess the remaining service life of those assets. Where it is likely that longer-life plants will require new transport and storage infrastructure, the reuse of existing assets should be limited to early demonstration projects to help reduce CAPEX.

CCS Capacity

As mentioned above, the UK will require a significant number of CCS plants and this may stress the supply chain. If CCS is deployed at scale globally then supply chain issues could become a major constraint to deployment rates.

Opportunities

To help establish a commercial-scale CO_2 transport and storage cluster by the mid-2020s, the UK will require fast-track implementation of a commercial-scale CO_2 capture project. A fast-track CO_2 capture project requires minimal risk, therefore favouring proven technology at commercial scale with a proven commercial framework.

The only sector that currently meets both criteria is power with CCS. One of the key lessons learnt from the UK CCS Competition in 2009 was the requirement of a payment mechanism to meet operating costs. This learning helped to establish the Contracts for Difference mechanism for CCS on thermal power. As the CfD is already in place for power decarbonisation then applying CCS to power will help speed up the process of enabling large-scale decarbonisation.

The capture of CO_2 can account for up to 60% of overall costs when using CCS for decarbonisation. However, some industrial processes already include CO_2 capture, therefore making the application of CCS significantly lower cost and less complex. These types of projects could be considered as CCS enabler projects, where the wider infrastructure could be established around a lower cost/lower complexity anchor.

The following industries have the potential to support CCS enabler projects:

- Natural gas processing (such as the Acorn project in Scotland)
- Fermentation
- Ammonia production
- Hydrogen production
- Biomethane production with anaerobic digestion
- Ethylene oxide
- Waste to transport fuels

There is significant potential for CCS in many countries. However, we would note that the market may not be as big as many would suggest, given that many countries do not have suitable geology. The UK is perfectly placed to develop this technology, given our access to depleted oil and gas fields in relatively close proximity to industrial centres. The UK needs to move quickly to be part of the first wave of commercial deployment, and to be able to exploit the IP developed in international markets.

The UK certainly has one of the best appraised geographies and geologies for CCS. This position is supported by work completed by the ETI in their CO_2 Storage Appraisal [REF 41], as well as the FEED output from the CCS demonstration programme and CCS Commercialisation programme. There may also be opportunities to explore business models to bring CO_2 from neighbouring EU countries for storage in the UK.

As many of the UK offshore oil and gas fields approach depletion, there is the opportunity to leverage relevant transferable knowledge for potential CCS storage geology. We also need to repurpose existing oil and gas assets. We would note, however, that many of these assets are at the end of their service lives. CCS projects predicated on asset repurposing will therefore need to assess asset condition carefully in order to reassure investors.

Rapid growth of our offshore wind capacity is required, which is achievable but there are several risks, uncertainty regarding capacity factors, integration challenges, system balancing and stability, as well as concerns that costs may increase.

3. System Integration and Balancing

3.1. System Integration

In the transition to a low-carbon energy system, the electricity sector plays a key role while facing two major challenges: ensuring system adequacy and maintaining the resilience and security of the grid (see Figure 20). These are the main system integration challenges for any grid. New renewable technologies, such as offshore wind and solar PV, are intermittent and geographically dispersed in locations not previously associated with large-scale grid inputs. Such technologies also fail to contribute to system inertia, further exacerbating the difficulty of maintaining a stable system.

In its assessment of the impact of the Net Zero system on networks, CCC has emphasised the need for increasing network capacity at both transmission and distribution level. Increased capacity, the report claims, will help to ensure that networks are better able to cope with the changes in generation mix, as well as with increased demand due to EVs and heat electrification. Net Zero has further considered the cost implications and suggests these costs are either small or can be controlled.

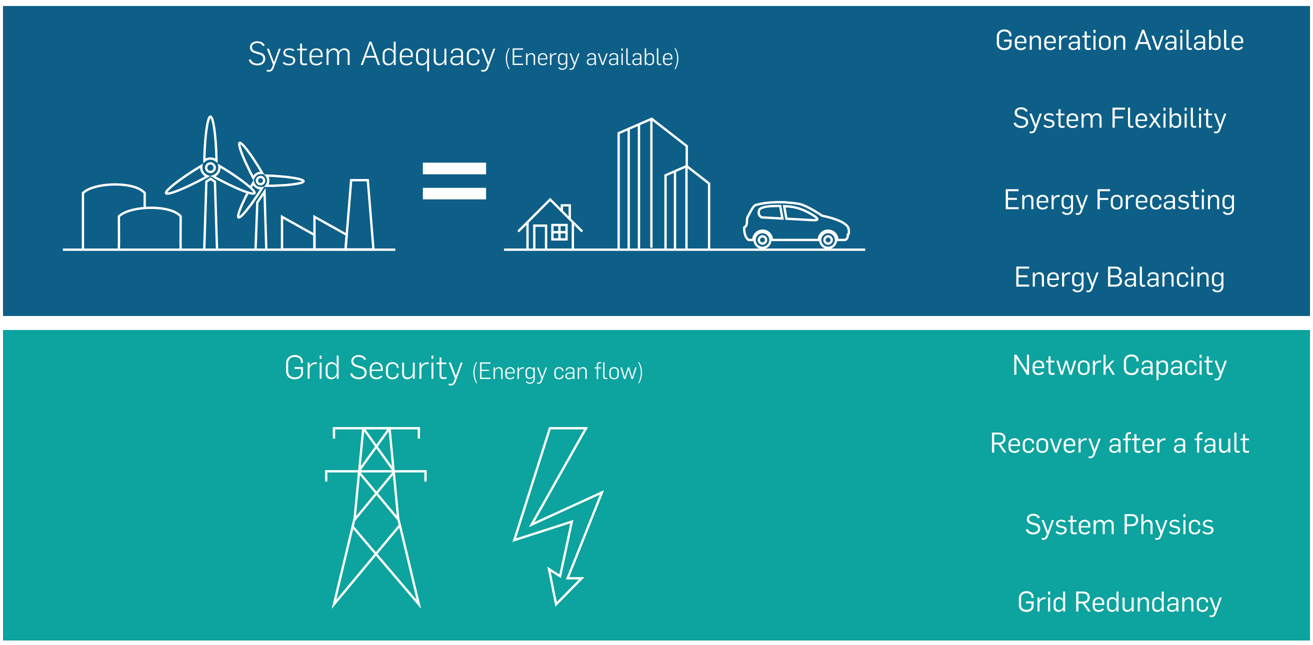
There are a variety of solutions to address the system integration challenges. However, we believe that these solutions come at a significant cost, which does need to be considered when assessing different technology options.

3.1.1. System Adequacy and Flexibility

The rise in low-carbon generation technologies, such as wind and solar PV, which are partly supported by Government mechanisms (RO, FiT, CfD), has impacted the viability of operating thermal fleets (gas). However, the intermittent nature of these technologies means there may be periods when there is insufficient renewable generation capacity to provide the energy the system needs. The more flexibility there is in the electricity system, the less of a challenge it will be to balance generation and demand.

System balancing is a technically complex task which must be achieved in real-time, 24 hours a day. Technology plays a key role. However, the design of the market and the structuring of contracts with generators, service providers and off-takers is vital to ensuring that technology can be efficiently applied.

Figure 20 – Requirements of a low-carbon energy system



Several solutions have already been implemented. These include Capacity Market, which aims to secure sufficient back-up capacity from non-intermittent sources in the short term. To address the long-term system adequacy and flexibility needs, the following areas need to be considered carefully:

- Improved Renewable Technology
  Newer renewable generation technologies, such as new wind turbines, have additional technical capabilities to provide the support the grid requires, without increasing wear and tear or any additional cost. However, progress to achieve system support from renewable generation is significantly lagging behind other new developments, and therefore has to be accelerated. This will effectively enable renewables to be part of the solution and not the problem
- Stand-alone Energy Storage versus Energy Storage with Renewable Generation
  There is currently limited energy storage capability across the UK network. Storage technologies (batteries, pumped-hydro) are usually developed as standalone applications, with their business case relying on limited revenue streams. However, there is a strong synergy between renewable energy projects and energy storage applications which could enable wider benefits. These include minimising intermittency and increasing the capability of hybrid solutions to provide grid services. The commercial risk of combined storage/renewable projects should also be significantly less compared to standalone storage projects. Therefore, policy should encourage renewable operators to incorporate storage/stability enhancing capabilities. As a general principle, intermittent generators should bear the cost of intermittency, or the added value of 'on demand' generators should be recognised
- Interconnectors
  Interconnectors play an important role in ensuring energy security, as well as providing flexibility in the grid. Developers looking at future interconnection to neighbouring systems should consider the value of flexibility that interconnectors bring. They should also provide incentive mechanisms for future projects
- Smart Grid Technologies
  Smart grid management provides the opportunity to offset network capacity investment and achieve higher degrees of flexibility. However, smart grid applications also have the potential to impact the balance of generation and demand if not coordinated with the ESO. A fitting parallel would be automated highspeed algorithm-driven stock trading, which has been shown to risk market instability.

Figure 21 – Positioning of Energy Storage Technologies [REF 42]

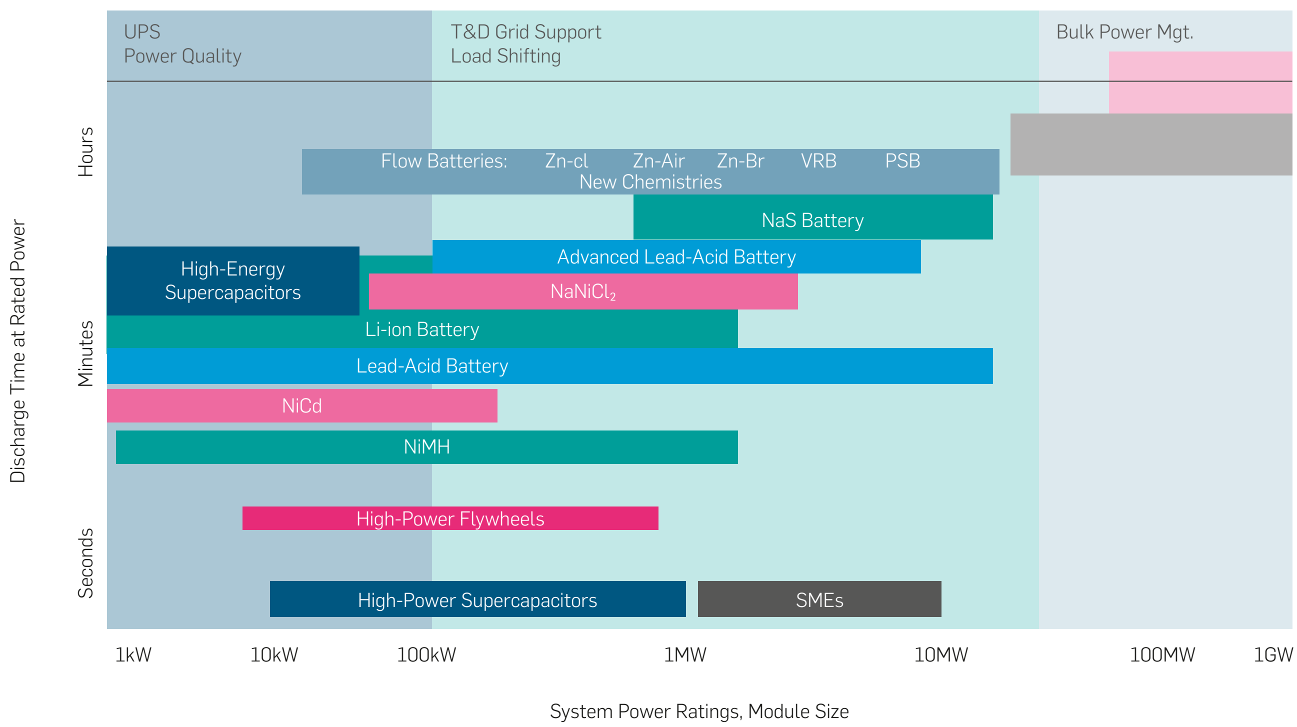
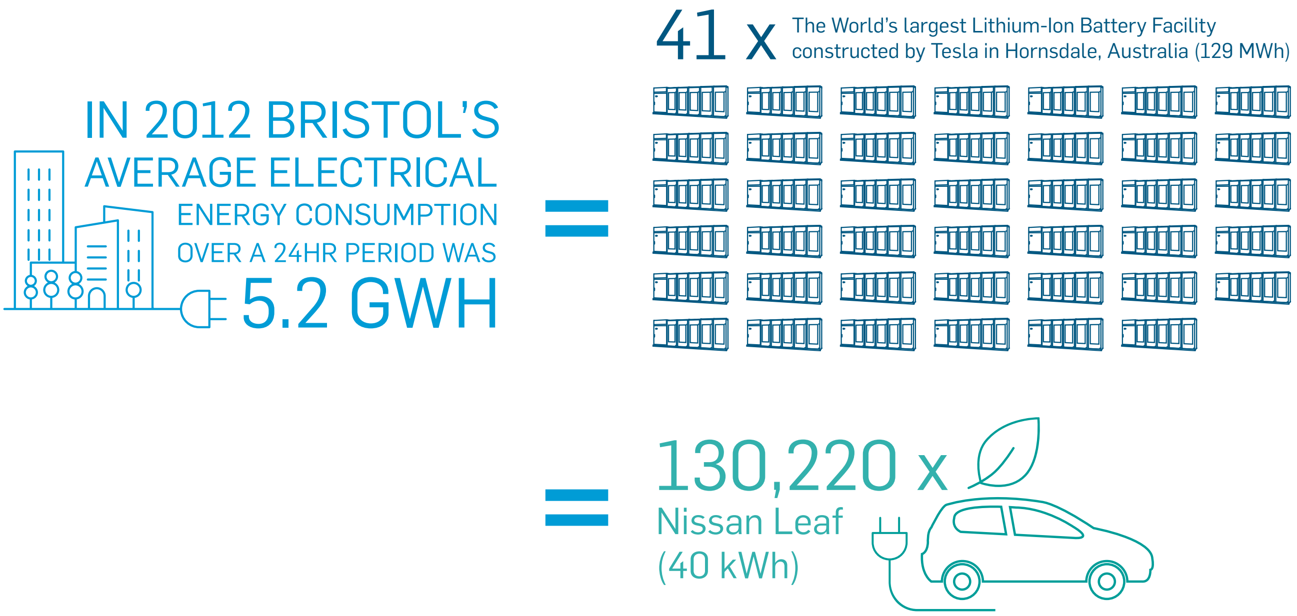


Figure 22 – Could we run the city of Bristol for 24 hours on batteries? [REF 1]



3.1.2. Energy Storage

Commentators frequently suggest that energy storage is the solution to the problem of intermittency in renewable generation. However, analysis of the available energy storage options demonstrates there is no storage system that can address grid-scale shortages of power. Figure 21 shows the available energy storage options in terms of how much power can be stored and for how long. For the avoidance of doubt, there is no battery, nor is there the prospect of such a battery, that could compensate for a prolonged (two hours or more) simultaneous drop in intermittent renewable generation at one or two major offshore wind farms.

To put this in terms of the system failure on 9 August 2019, the failure was due to the loss of the partially-commissioned Hornsea One Offshore Wind Farm (approx. 800MW), a few minutes after the loss of the Little Barford CCGT (approx. 320MW).

These losses caused frequency disruption leading to automatic shutdown of parts of the system. The world's largest lithium battery storage installation at Hornsdale, Australia has a capacity of 129MWhr, enough to replace Hornsea for less than 10 minutes.

The concept of Vehicle to Grid, enabled through the smart grid, is also frequently put forward as a way to consolidate vehicle battery storage capacity at a time of generation shortfall. In our Road to Decarbonisation analysis, we estimated how many Nissan Leafs it would take to sustain the city of Bristol for six hours. The result is shown in Figure 22.

The House of Commons Briefing Paper on Electric Vehicles and Infrastructure [p.23 REF 43] notes the following on Vehicle to Grid opportunities:

"Wider proliferation of electric vehicles will continue to add demand to the grid. However, the batteries in the vehicles could become an asset to National Grid, as they have the potential to be used for grid balancing. The concept, known as 'Vehicle to Grid' (V2G), is that when supply is low and demand high, EVs connected to the grid to charge can instead release power back into the grid. Owners of the vehicles can then be paid for this balancing service in a similar way to electricity storage unit operators. In theory, if a vehicle is needed to be charged for a certain time the owner could register that time and this would override the use of the car as a power source."

Tapping into the storage capacity of EVs could provide a potential balancing function in a Net Zero system with a high penetration of intermittent renewable sources. To capitalise on this potential, it is essential the UK develops a national charging network that enables interoperability of suppliers. At present, the UK's EV charging market is characterised by large charging networks that operate vertically integrated systems, with different approaches to access and payment. While exceptions exist, overall there are few cross-network agreements among UK companies.

Fundamentally, V2G is about the exchange and management of data. At present, there is a lack of common standards for facilitating and managing the exchange of data and electricity between generators/suppliers and EV users. While the solutions will ultimately be industry-led, we believe that this component, if ever realised on a large scale, needs to be driven by Government policy.

3.1.3. Grid Security

The primary role of electrical networks is to enable the transfer of power from generators to demand centres. Today, this role is no longer based on a one-way flow of energy, as there are significant volumes of generation of varying sizes connected to the network at demand centres. This results in a bidirectional power flow through the system. Most networks in the UK are regulated and facilitating the connection and flow of electricity from generation source to consumer requires continual investment in infrastructure.

Over the past decade, the networks have faced several challenges. These include:

- Anticipation of future generation and demand (type, location)
- Level of risk to the networks and considerations of redundancy and resilience
- Integration of new technologies with different characteristics and potential impacts on the system (e.g. reduction of system inertia as a result of increasing the volume of non-synchronous generation, such as solar PV and Wind)
- The changing balance between operational actions and investments and new requirements for managing generation and demand in the distribution networks, with additional requirements placed on distribution system operators (DSOs)

There is a risk that the increasing cost of maintaining networks could significantly outweigh the benefits they provide in a centralised model. Therefore, it is prudent that the Government considers the following:

- The networks, as regulated assets, require certain up-front upfront investments; they also need to strike a balance between non-build solutions, smart grid technologies and investment in network capacity
- Additional network capacity provides reliability and resilience, which will be key as generation and demand become more volatile
- Network operators should be encouraged to embed flexibility products, not as a temporary way of addressing network needs, but of offsetting investment in asset-based solutions
- The impact of decarbonisation across other sectors (mainly transport and heat) could be significant. We should therefore ensure that networks do not become barriers to decarbonisation elsewhere by making sufficient investments against appropriate revenue recovery mechanisms

3.2. National Infrastructure Considerations

As the energy system adapts to decarbonisation, there will be areas in which the former model of highly centralised energy provision is no longer applicable. However, some operational capabilities will still be required, resulting in the need for infrastructure but at a very low level of utilisation.

As an example, Net Zero anticipates roll-out of a large number of hybrid heat pumps that operate most of the time using electricity (increasing demand on the electricity system). For a small amount of time (perhaps 5%), during particularly cold weather, these pumps would also require gas (potentially hydrogen). Therefore, gas delivery infrastructure would be needed, similar to that which we have today, but would only be utilised 5% of the time.

This scenario raises the question: how will the costs of maintaining and operating such gas infrastructure be recovered? More generally, elements of our national infrastructure today will move from highly utilised to marginally utilised, but still essential. And at what point does this infrastructure become uneconomic and do we subsidise or decommission it?

3.3. System Optimisation

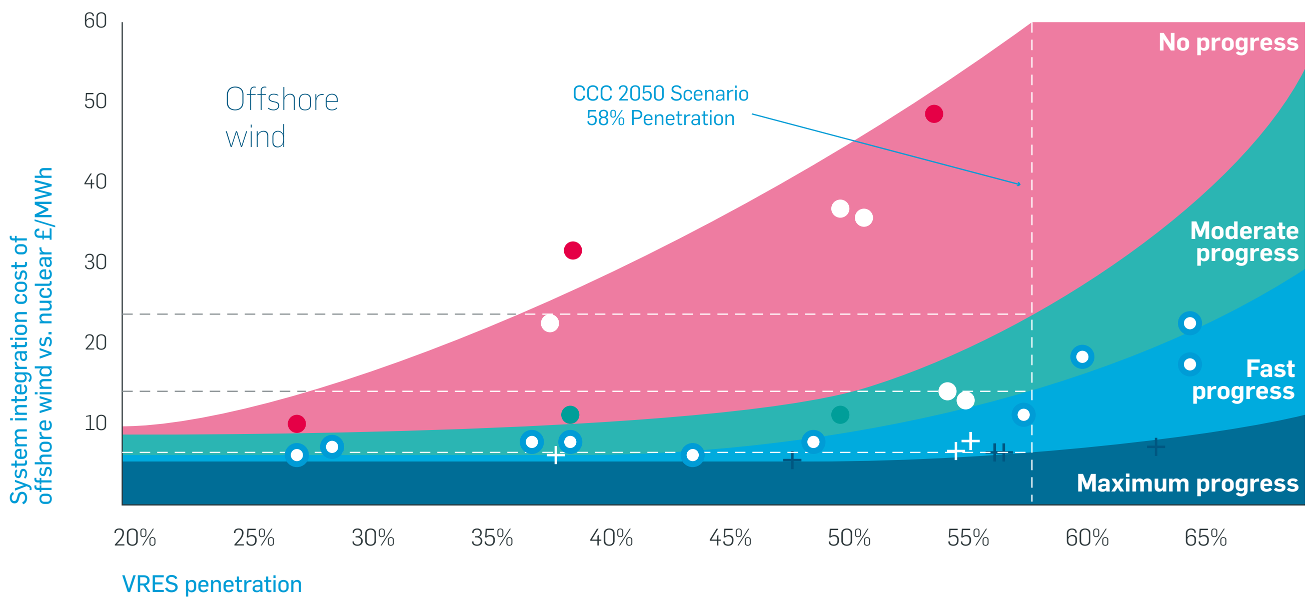
Much of the published energy system modelling attempts to model an optimal system delivering energy at least cost. CCC, quite properly, endeavours to identify least cost pathways to achieve our carbon reduction goals. Modelling therefore relies on input assumptions regarding the cost of each element within the system.

The Net Zero scenario shows intermittent renewables contributing 58% of electricity in 2050. The remaining 42% comprises mostly CCGT and bioenergy (both with CCS) and nuclear. The system-wide requirements and costs of supporting high levels of intermittent generation are the subject of much academic debate. The Net Zero report suggests that up to 40% provision by intermittent renewables will incur system integration costs of about £10/MWh of renewable power. At 50% penetration, the cost may be £20/MWh or more, rising as the proportion of intermittent generation increases. Modelling of system integration costs for offshore wind shows a wide range of outcomes, as presented in Figure 23 (based on Net Zero technical annex Figure B2.1) [REF 21].

Net Zero's assumed costs of the major electricity generation sources in 2025 and 2050 are summarised in Table 6. We assume that these costs are LCOE at the point of generation If so, then as renewables penetration increases beyond 50%, the incremental costs of both offshore wind and solar would need to be increased by £20/MWh or more to allow for system-wide costs. In these circumstances, the incremental costs of offshore wind and nuclear in 2050 are the same and both less than gas with CCS.

There is significant uncertainty in predicting these costs. It is clear that modelling to achieve system optimisation must take account of whole system costs. Furthermore, in order to achieve an optimal balance between different forms of generation, system costs should be allocated to the technology that requires their support. The sensitivity of the results to changes in input assumptions must also be clearly stated.

Figure 23 – System Integration Costs Offshore Wind v Nuclear (based on Fig B2.1 from [REF 21])



Notes. Integration costs are expected to be similar for onshore wind, but will differ for solar as it has a different seasonal generation profile. Estimates of system integration costs for a system with a carbon intensity of 100gCO_2/ kWh. 'No progress' has no added system flexibility. 'Moderate progress' includes 5 GW of new storage, 25% DSR uptake and 10 GW of interconnection. 'Maximum progress' includes 15 GW of interconnection capacity (15 GW) and 100% uptake of DSR.

Based on the LCOE figures for 2050 and making pragmatic allowance for technical and commercial risk, we find that beyond 50% renewables the incremental cost per MWh for offshore wind, CCGT with CCS and nuclear are in the same range. These results are presented in Figure 24.

The historic focus on LCOE at the point of generation as a measure of competitiveness in electricity generation is outdated by the complexities of the modern integrated energy system. It is also potentially grossly misleading. LCOE comparisons, though simple to understand, should be avoided in discussions of energy policy.

We also believe that system architecture needs to be developed based on whole system costs and designed to minimise the cost of energy to the customer.

Table 6 – Costs of Generation by Technology [REF 3]

Technology	LCOE at the Point of Generation in 2025 (£/MWh)	System Integration Costs for Inttermitency (£/MWh) *	**2025 Cost of Electricity (£/MWh)**	LCOE at the Point of Generation in 2050 (£/MWh)	System Integration Costs for Inttermitency (£/MWh) **	**2050 Cost of Electricity (£/MWh)**
Offshore Wind	69	10	79	51	20	71
Solav PV	47	10	57	41	20	61
Nuclear	98	0	98	71	0	71
Gas CCS	79	0	79	79	0	79

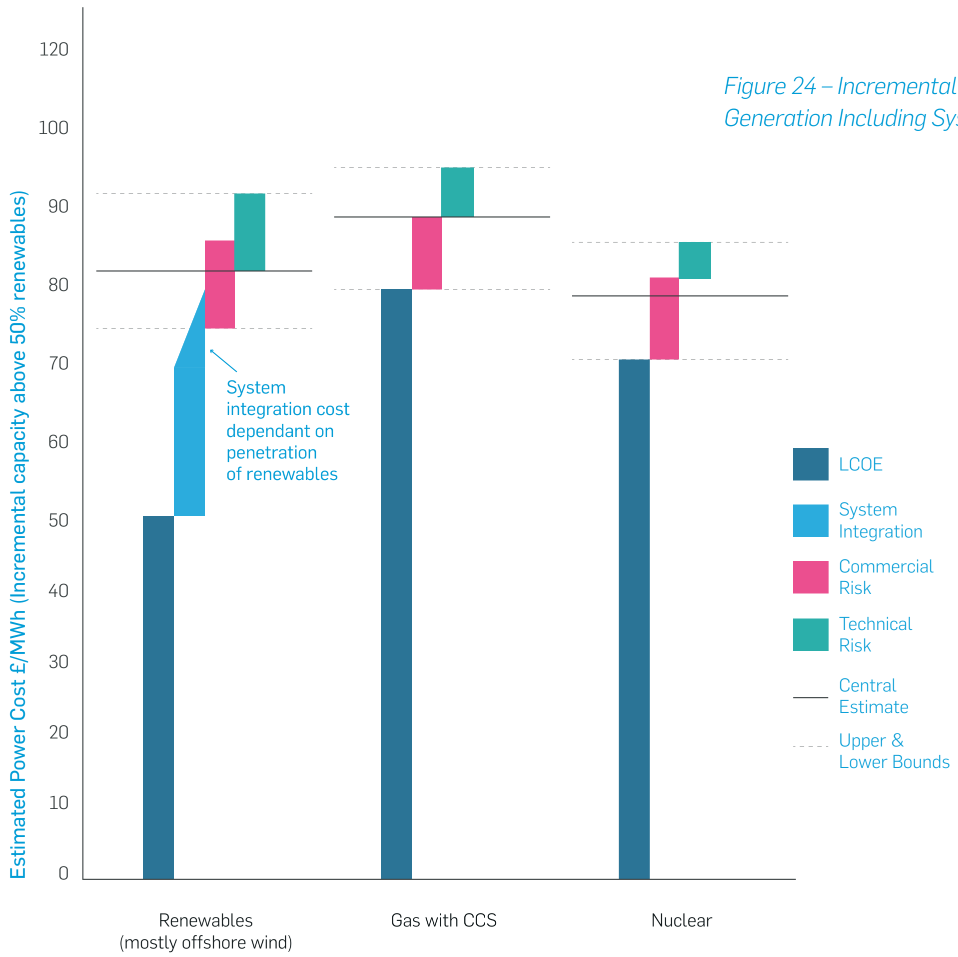


Figure 24 – Incremental Cost of Generation Including System Integration

We have no Carbon Capture Storage industry, and our current pilot project must be accelerated; the projected mid-2020s date will be too little, too late.

4. The Energy System Architect

The Net Zero system is incredibly complex. It will require detailed input from a broad set of Government and industry stakeholders to even articulate the challenge, let alone deliver it. All of the elements of the Net Zero energy system are interconnected and interdependent. They are also dependent on other developments of national infrastructure, cities and industry.

As we move towards 2050, the energy system will go through a rapid period of change. The major capital assets involved have decadal lifespans and the outcome of decisions taken in the next few years will impact our national life and economic wellbeing for years to come. In a liberalised and competitive 'free market', investment decisions are rarely made on such a long-term basis, neither are they likely to support the deployment of billion-pound, 'first-of-a-kind' projects. Therefore, Government intervenes in the market. Offshore wind is a clear example; a sector that has developed because Government provided massive support to initiate early projects. Without that support, no offshore wind projects would have been built.

Government is effectively deciding what projects will be built, and yet it does not have an overall system architecture to guide the markets or ensure long-term optimisation. Offshore wind continues to be deployed. CCS, essential to the Net Zero scenario, has made little real progress for over a decade. And nuclear is stalled, despite Government policy to build 15GW to replace our existing nuclear fleet.

In our view, it is imperative that such a far-reaching programme of change should have a guiding mind and coordinating body. Such a mind and body are needed to ensure that the drivers from different stakeholder groups (be they Government departments whose policies will impact Net Zero, or industry and special interest lobbies) are aligned to achieve system optimisation against evolving demands and available technologies. We believe this is the function of the Energy System Architect (ESA).

As Net Zero is now a legally binding requirement, the ESA function should have the weight of Government authority, but with independence. The ESA function could be discharged by NDPB with a limited lifespan and a well-defined charter. Such a critical national programme merits a guiding mind; one that will be held solely accountable for delivery.

The system architecture will need to reflect the developments of the various Net Zero system components in a dynamic way. There is no possibility of defining a grand plan now and following it for the next 30 years. The plan will need to evolve in response to changing demand, actual performance and market pressures, both domestic and global.

We know that the Net Zero system as described is a 'proof of concept', and that the pathways to delivering this system are being developed in more detail. We have identified the dependence on CCS as a major risk. In Figure 25, we have attempted to show one version of the potential consequences of failure to initiate a meaningful scale CCS demonstrator early, and the subsequent failure to deliver CCS at the scale envisaged:

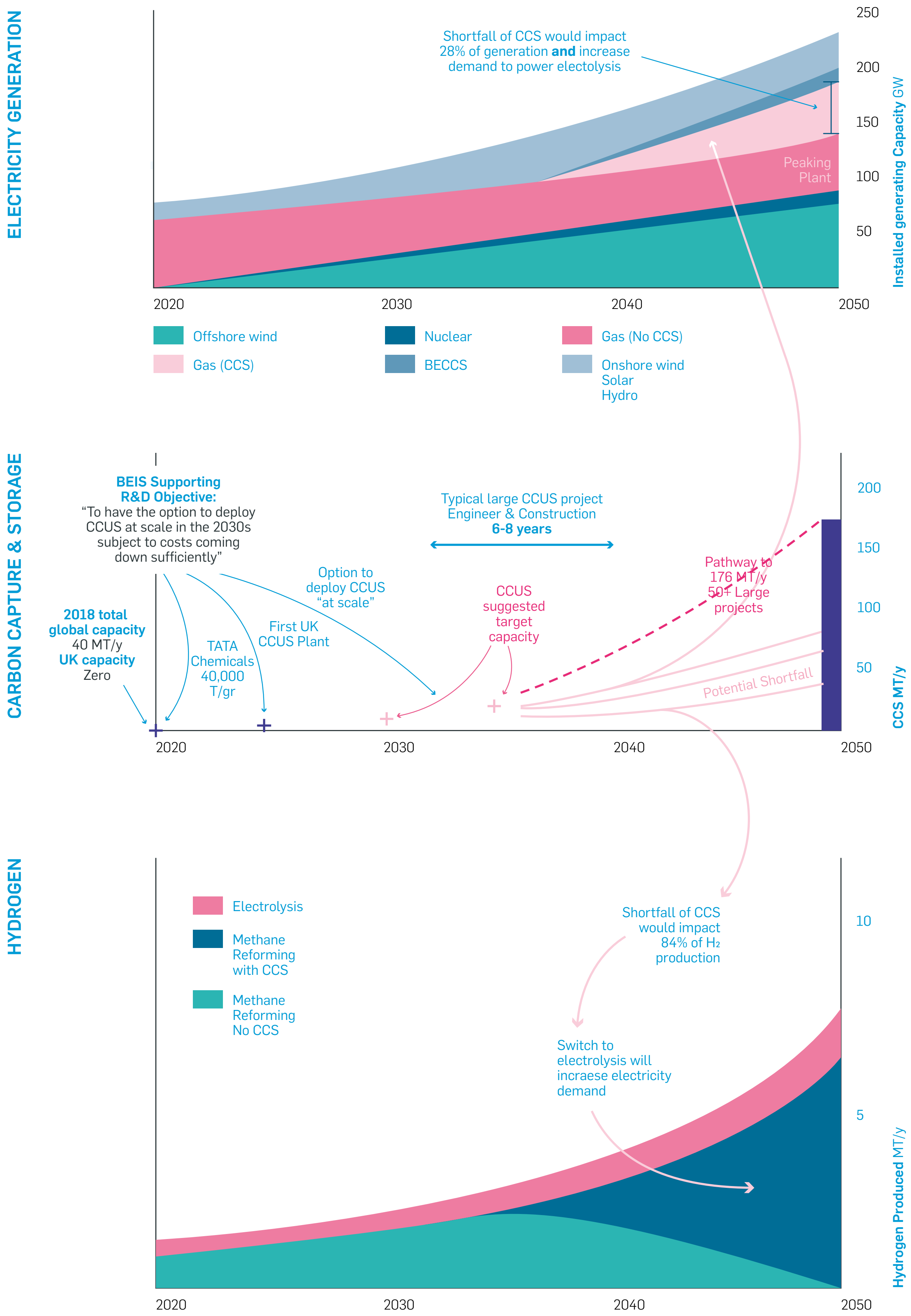
- By the mid-2030s, it becomes apparent that CCS deployment will be much less than the 176Mt/yr set out in Net Zero; a lower amount of CCS will be achieved and at higher cost than assumed in Net Zero
- The consequence is that CCS must be targeted on industrial emissions that cannot be avoided, and for which there is no viable alternative. CCS for key CO_2-producing industrial sources must be heavily subsidised, or these sources will go out of business
- CCGT power with CCS becomes much more expensive than renewables or nuclear; BECCS also becomes more expensive
- 28% of the 2050 power generation is now non-viable; the only alternatives are more renewables with sharply increasing integration costs or more nuclear

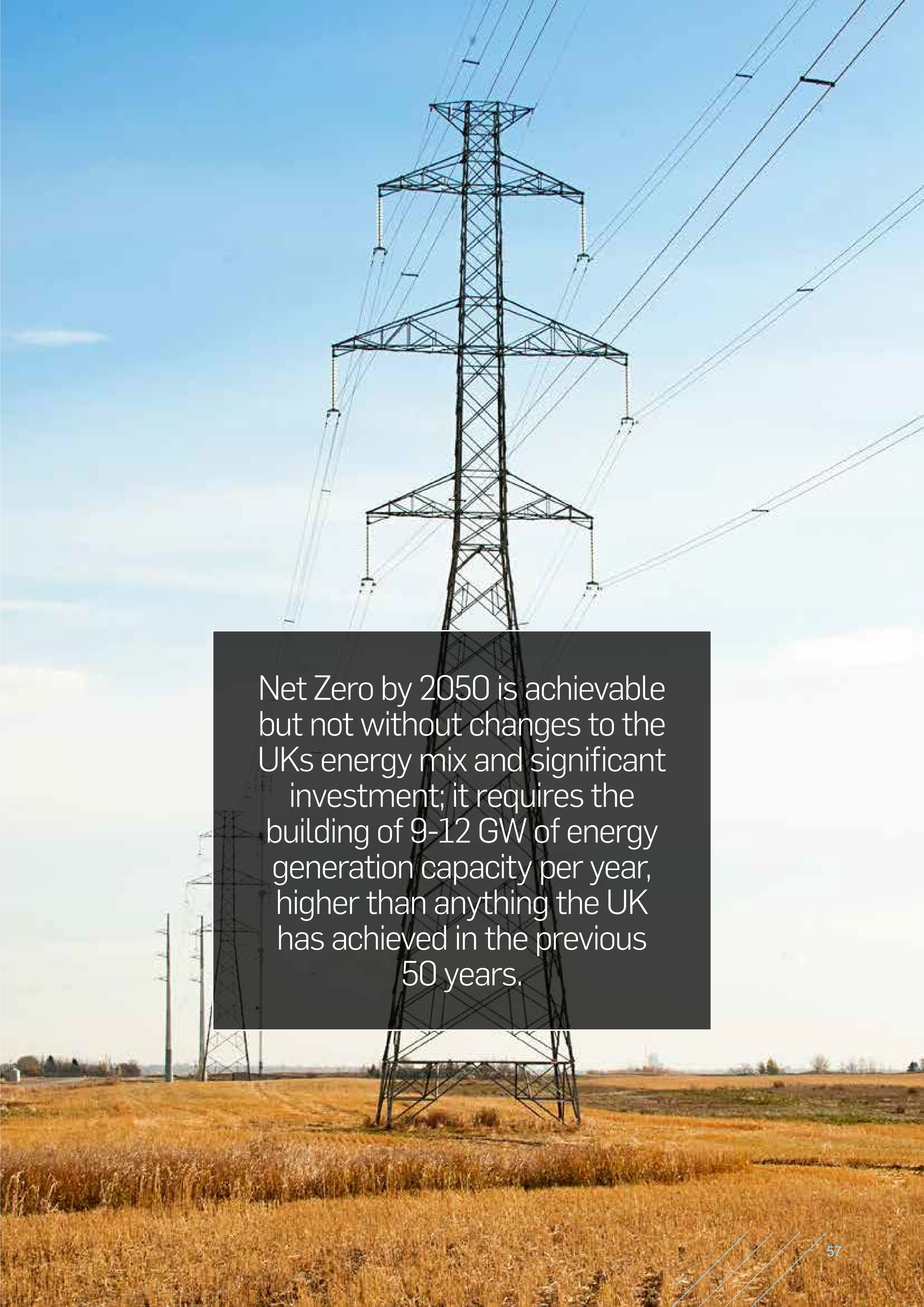
- Nuclear is the most viable alternative but, due to the reduced amount of nuclear in Net Zero, the UK's nuclear capability has not geared up; the UK has not pursued SMRs or Gen IV with vigour and no new large nuclear plants (beyond SZC and Bradwell B) have been progressed. It will take ten years to commission a new large nuclear plant
- The UK is now 'boxed in' to a sub-optimal system dependent on renewables for over 75% of its power generation; system stability is therefore a major issue and the marginal costs of further capacity are very high
- The planned use of hydrogen (26% of our energy) must be scaled down substantially as the production by MR and CCS is sharply reduced. Part of the hydrogen load is transferred directly to electricity, exacerbating the generation shortfall. The use of electrolysis can partly make up for the reduction in hydrogen from MR, but this further exacerbates the generation crisis

This is an entirely credible alternative scenario. It demonstrates the importance of keeping alternative options open and developing an actively managed and constantly updated system architecture. This architecture needs to be maintained by a technologically neutral ESA empowered to both inform policy and direct Government support to areas that will deliver the optimal system and maintain strategic flexibility.

At the CBI annual dinner in 2006, the then UK Prime Minister spoke of failure to take long-term decisions on energy as a "dereliction of my duty". Since that time, much has changed and yet nothing has changed. Failure to address system architecture in a rigorous, transparent and technologically neutral way remains a dereliction of duty – one which will have major consequences for the UK's energy future.

Figure 25 – Timelines for Net Zero 'Major Thrusts' and Potential Interactions





Net Zero by 2050 is achievable but not without changes to the UKs energy mix and significant investment; it requires the building of 9-12 GW of energy generation capacity per year, higher than anything the UK has achieved in the previous 50 years.

5. Net Zero Risk Register

The risks detailed here reflect our main findings from the Engineering Net Zero assessment and can be used as a basis for further discussions on successfully delivering Net Zero (H – High, M – Medium).

Risk	Level	Description	Consequence	Mitigation
1.	H	**CCS commercial structure/policy** Challenges exist around the structuring of project finance, security of revenue streams, transport infrastructure and final storage liability. Project structure is critical to raise finance. To date there is no precedent, each cluster may have different participants so a single structure will not suit all. Projects depending on use of existing offshore oil and gas assets must evaluate the condition and serviceability of the assets. Contractors will be reluctant to accept long-term liability for the performance of such assets. Failure to structure projects will result in greatly reduced CCS capacity.	The Net Zero scenario is dependent on rapid development of CCS. Failure to develop CCS makes the Net Zero scenario non-viable. 28% of power generation and 84% of hydrogen production will have to be substituted with alternatives. CCS-dependent industries with no alternative will not be able to operate; balancing CO_2 removal from the atmosphere will be needed.	Government should assume both the commercial transport risk and long-term storage liability. Reconfigure CCS strategy to focus only on CO_2 generators who have no other option.
2.	H	**CCS deployment** Total installed CCS capacity in UK today is zero. Up to 176MtCO_2 per annum may be required for Net Zero – the deployment rate required to meet this target is hugely challenging.	The Net Zero scenario is dependent on rapid development of CCS. Failure to develop CCS makes the Net Zero scenario non-viable. 28% of power generation, 84% of hydrogen production is impacted. CCS-dependent industries will not be able to operate or will have to compensate.	Expedite CCS demonstrator project(s). Reconfigure CCS strategy to focus only on CO_2 generators who have no other option.
3.	H	**Hydrogen production and distribution technical risks** The rate of deployment of hydrogen production plants is challenging. This is compounded by the cost, logistics and phasing of the extensive work needed on the distribution network (both national and local), as well as the dependency on CCS with its associated risks.	Hydrogen is an important element to various aspects of decarbonisation in Net Zero: domestic heat, industry, shipping, surface transportation. If hydrogen is not successfully deployed, the demand on electricity will increase which will require additional capacity to be installed.	Expedite current hydrogen research and proposed full-scale community demonstration projects. Assess alternative (non-CCS dependent) hydrogen production methods and support development of most promising candidates.

4.	H	**Decarbonisation of domestic heating – adoption risk through scale and pricing** Net Zero requires around 19 million heat pumps to be installed in homes (1/4 installed as hybrid heat pump systems). The rate of deployment is substantial, and there are likely barriers to adoption due to the high cost of purchase and installation.	A slower uptake and rate of installation of heat pumps will challenge the ability to decarbonise domestic heating.	Greatly increase electrification of heating (and system generating capacity). Review of Government subsidy scheme (Domestic Renewable Heat Incentive) to support home owners' transition costs.
5.	H	**Renewable Energy Sources: System Costs Associated with High Intermittent Penetration** The costs associated with system balancing at high renewables penetration are uncertain. Net Zero estimates £20/MWh at 50% penetration, rising steeply as penetration increases.	Modelling to optimise the Net Zero system without a full understanding of these costs may result in a sub-optimal system with long-term cost impacts to the consumer.	Develop further exhaustive modelling, with extensive independent peer review to evaluate the robustness of modelling and the sensitivity of results to variable input assumptions.
6.	H	**System Integration: lack of overall Engineering System Architect and/or Programme Delivery Office** Net Zero by 2050 is now enshrined in law and will be one of the most complex political, scientific and engineering challenges of our generation. Accountability for Net Zero system coordination and delivery is therefore needed.	Without an Energy System Architect (ESA) and a strategic framework, there is a significant risk that short-to-medium term decisions will compromise delivery. Net Zero will either not be delivered or will result in a sub-optimal system with long-term economic impacts.	Create an ESA organisation that is both empowered to direct Government support and independent of any one Government department.
7.	H	**Nuclear: major capital programme construction risk** Nuclear projects are complex capital programmes where return on investments can be impacted through construction overruns, with potential for construction cost increases.	If the risk around construction cost overruns cannot be managed, there is a potential that large-scale nuclear will continue to be un-investable and will not form a necessary part of the Net Zero system.	Continue to develop alternative financial models (e.g. RAB) which could support this element for investors. Leverage the benefits of a construction learning curve from technology repetition.

8.	M	**Offshore wind: pricing risk** The latest CfD auction strike prices for offshore wind are not yet proven viable, as projects are not due to come online until the mid-2020s. Separately, offshore wind programmes are likely to need to exploit conditions where only floating turbines are an option in the future. The learning curve for floating offshore wind may require the strike price to increase.	Strategy of very high offshore wind generation based on continuing low generating costs and not fully recognising the system integration costs could lead to sub-optimal generation mix if OSW prices rise. Could also impair development of alternatives. Thus increasing system vulnerability.	Ensure OSW is assessed on a whole system cost basis. Closely monitor OSW load factors and global OSW supply chain pricing as floating technology is deployed. Ensure that firm power alternatives (nuclear and CCGT with CCS) are developed in sufficient quantity to be viable.
9.	M	**Nuclear: pricing and affordability risk**	Nuclear deployment is reduced to minimum and UK nuclear capability declines to non-viable levels such that the option of nuclear is effectively abandoned	Develop a fit for purpose financial model (possibly RAB) that will facilitate the continued deployment of large scale nuclear. Pursue advanced nuclear SMR with clear objectives.

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