



## NET ZERO NORTH WEST CLUSTER PLAN

Work Package 6 - Grid Scale Low Carbon Dispatchable Power

Document prepared For the Net Zero North West Cluster Plan Consortium  
By Uniper UK Limited and Uniper Technologies Limited



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## Contents

ABBREVIATIONS .....	6
1. Scope .....	8
2. Introduction.....	8
3. Existing Power Generating Assets in the Cluster.....	9
4. Technology Review.....	10
4.1 Introduction.....	10
4.2 Gas with Post-Combustion Carbon Capture, Storage and Utilisation.....	13
4.2.1 Technology Description .....	13
4.2.1.1 Carbon Capture .....	13
4.2.1.2 Post-Combustion Capture.....	14
4.2.1.3 Transport and Storage.....	15
4.2.1.4 Utilisation .....	16
4.2.2 Current Technology Status .....	16
4.2.2.1 OEM Status .....	16
4.2.2.2 Current Projects.....	17
4.2.2.2.1 United Kingdom (UK).....	17
4.2.2.2.2 International.....	18
4.2.2.3 Feasibility.....	18
4.2.2.3.1 New Build.....	18
4.2.2.3.2 Retrofit.....	19
4.2.3 Efficiency.....	19
4.2.4 Emissions .....	20
4.2.5 Flexibility and Operational Constraints.....	22
4.2.6 Requirements.....	23
4.2.7 Forecast Costs.....	23
4.2.7.1 CAPEX.....	23
4.2.7.2 OPEX .....	24
4.3 Hydrogen Gas Turbines .....	25
4.3.1 Technology Description .....	25
4.3.2 Current Technology Status .....	26
4.3.2.1 OEM Status .....	26
4.3.2.2 Current Projects.....	32
4.3.3 Feasibility.....	34
4.3.3.1 New Build.....	34
4.3.3.2 Retrofit.....	35
4.3.4 Efficiency.....	36

4.3.5	Emissions .....	37
4.3.6	Flexibility and Operational Constraints.....	41
4.3.7	Requirements.....	42
4.3.7.1	Hydrogen Production .....	42
4.3.7.2	Hydrogen Purity.....	44
4.3.7.3	Connection Requirements .....	44
4.3.8	Forecast Costs.....	45
4.3.8.1	CAPEX.....	45
4.3.8.2	OPEX .....	46
4.4	Levelised Cost of Electricity.....	48
4.4.1	Methodology.....	48
4.4.2	Base Case .....	49
4.4.2.1	Today Base Case.....	50
4.4.2.2	FOAK Base Case.....	51
4.4.2.3	NOAK Base Case.....	52
4.4.3	High Efficiency CCGT.....	55
4.4.4	CO <sub>2</sub> Avoidance Cost.....	56
4.4.5	Load Factor .....	57
4.4.6	Carbon Price .....	58
4.4.7	Hydrogen Price .....	59
4.5	Comparison .....	60
4.6	Novel Technologies.....	61
4.6.1	Pre-combustion Capture .....	61
4.6.2	Oxyfuel Capture.....	62
4.6.3	Small Modular Reactors .....	62
4.6.4	Supercritical CO <sub>2</sub> Brayton Cycles .....	62
4.6.5	Hydrogen Internal Combustion Engines .....	63
4.6.6	Hydrogen Fuel Cells .....	63
4.6.7	High Temperature Fuel Cells in Combined Cycles .....	63
4.6.8	Smart Advanced Humid Air Turbine (Smart-AHAT).....	63
4.6.9	CCGT with Exhaust Gas Recirculation .....	63
4.6.10	Allam Cycle.....	64
4.6.11	Wind Driven Thermal Pumping .....	64
4.6.12	Ammonia Gas Turbines.....	64
5.	Regulatory Review & Business Models .....	65
5.1.	Current Regulation / Policy .....	65
5.2.	Revenue Models.....	65

- 5.2.1. Gas with CCS for Power (DPA) ..... 65
- 5.2.2. Hydrogen for power..... 66
- 6. A future role for dispatchable power..... 67
  - 6.1. Future Energy Forecasts..... 67
    - 6.1.1. General Trends..... 67
  - 6.2. Dispatchable Low Carbon Generation ..... 69
    - 6.2.1. Collated Trends ..... 70
      - 6.2.1.1. Electricity Generation from Hydrogen Turbines..... 71
      - 6.2.1.2. Electricity Generation from Gas Turbines with CCS ..... 73
      - 6.2.1.3. Electricity Generation from dispatchable low carbon gas Turbines..... 74
  - 6.3. Low Carbon Dispatchable power in the North West and North East Wales ..... 76
    - 6.3.1. Possible Locations ..... 76
    - 6.3.2. H<sub>2</sub> Gas Turbines ..... 77
      - 6.3.2.1 H<sub>2</sub> Gas Turbine Capacity and Generation ..... 77
      - 6.3.2.2 H<sub>2</sub> Generation Profile ..... 79
      - 6.3.2.3 H<sub>2</sub> supply for power ..... 80
    - 6.3.3. Natural Gas Turbines with Carbon Capture ..... 80
- 7. Summary..... 80
- Table of Tables ..... 81
- Table of Figures..... 82
- References ..... 84

## ABBREVIATIONS

AHAT	Advanced Humid Air Turbine
ASU	Air Separation Unit
ATR	Autothermal Reforming
BECCS	Bioenergy with Carbon Capture (Utilisation) and Storage
BEIS	Department of Business, Energy and Industrial Strategy
BOP	Balance of Plant
CAC	CO <sub>2</sub> Avoidance Cost
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CCUS	Carbon Capture Utilisation and Storage
CEMS	Continuous Emissions Monitoring System
CH <sub>4</sub>	Methane
CHP	Combined Heat and Power
CO	Carbon Monoxide
CO <sub>2</sub>	Carbon Dioxide
DCC	Direct Contact Cooler
DLE	Dry Low Emissions
DLN	Dry Low NO <sub>x</sub>
DSEAR	Dangerous Substances and Explosive Atmospheres Regulations
DOE	US Department of Energy
EfW	Energy from Waste
EGR	Exhaust Gas Recirculation
EIB	European Investment Bank
EOR	Enhanced Oil Recovery
FCR	Fixed Charge Rate
FEED	Front-End Engineering Design
FGR	Flue Gas Recirculation
FOAK	First of a Kind
GE	General Electric
GHG	Greenhouse Gas
GT	Gas Turbine
GWP	Global Warming Potential
H <sub>2</sub>	Hydrogen
H <sub>2</sub> O	Water
H <sub>2</sub> P	Hydrogen to Power
HRSG	Heat Recovery Steam Generator
HSS	Heat Stable Salts
IGCC	Integrated Gasification Combined Cycle
ISCF	Industrial Strategy Challenge Fund
LCOE	Level Cost of Electricity
LCH	Low Carbon Hydrogen
LHV	Lower Heating Value
LPM	Lean Premixed
MCFC	Molten Carbonate Fuel Cells
MEA	Monoethanolamine
MHPS	Mitsubishi Hitachi Power Systems
N <sub>2</sub>	Nitrogen
NOAK	Nth of a Kind
NG	Natural gas
NPV	Net Present Value
NTS	National Transmission System
O <sub>2</sub>	Oxygen
OCGT	Open Cycle Gas Turbine

OECD	Organisation for Economic Co-operation and Development
OEM	Original Equipment Manufacturer
OPEX	Operational Expenditure
PAFC	Phosphoric Acid Fuel Cell
PCC	Post-Combustion Capture
PHWR	Pressurised Heavy Water Reactor
PWR	Pressurised Water Reactor
R&D	Research and Development
sCO <sub>2</sub>	Supercritical CO <sub>2</sub>
SCR	Selective Catalytic Reduction
SMR	Small Modular Reactors
SMR	Steam Methane Reformer
SOFC	Solid Oxide Fuel Cell
TRL	Technology Readiness Level
T&S	Transport and Storage
UK	United Kingdom
UKRI	United Kingdom Research and Innovation
WLE	Wet Low Emissions

## 1. Scope

This report will consider and discuss the role of low carbon dispatchable power generation in the transition to a Net Zero future. It will investigate the technical and commercial aspects of technologies considered feasible to deliver at scale (>300MW) dispatchable power generation onto the National Transmission system in 2030 and further into the future. Accepted, published future energy scenarios will be reviewed and compared to help inform a view of future requirements for dispatchable power, with these being related back to the North West context. Current or proposed policy will be reviewed to inform potential revenue models / commercial frameworks to support the investment in and operation of such plant.

## 2. Introduction

The UK Government was the first major economy to put into law a target to reduce all of its greenhouse gas emissions to net zero by 2050, entailing significant change across all sectors.

It is recognised that a successful power sector transition must preserve the robustness of the system today, ensuring security of supply is maintained.

As more renewable generation connects into the electrical grid, the dependency on dispatchable, flexible generation increases. In today's system, much of this dispatchable power is fueled by natural gas, contributing to the UK's GHG emissions. In order to reach net zero, new technologies and approaches will be required to provide low or zero carbon dispatchable power.

Hydrogen Gas Turbines and Natural Gas Turbines with CCUS are shown to have a vital role in delivering flexible reliable power and therefore securing supply in the future decarbonised systems. However, investment in these technologies and successful deployment is dependent on wider infrastructure developments, support for first projects, the development of market and regulatory frameworks, and the establishment of business models.

### 3. Existing Power Generating Assets in the Cluster

Multiple power generation sites operate across the North West of England and North Wales, with these deploying a range of technologies and offering varying levels of reliability, availability and flexibility.

The image below shows a map of Major Power Producers in the region, as defined by section 5.72 of the Digest of UK Energy Statistics (1)

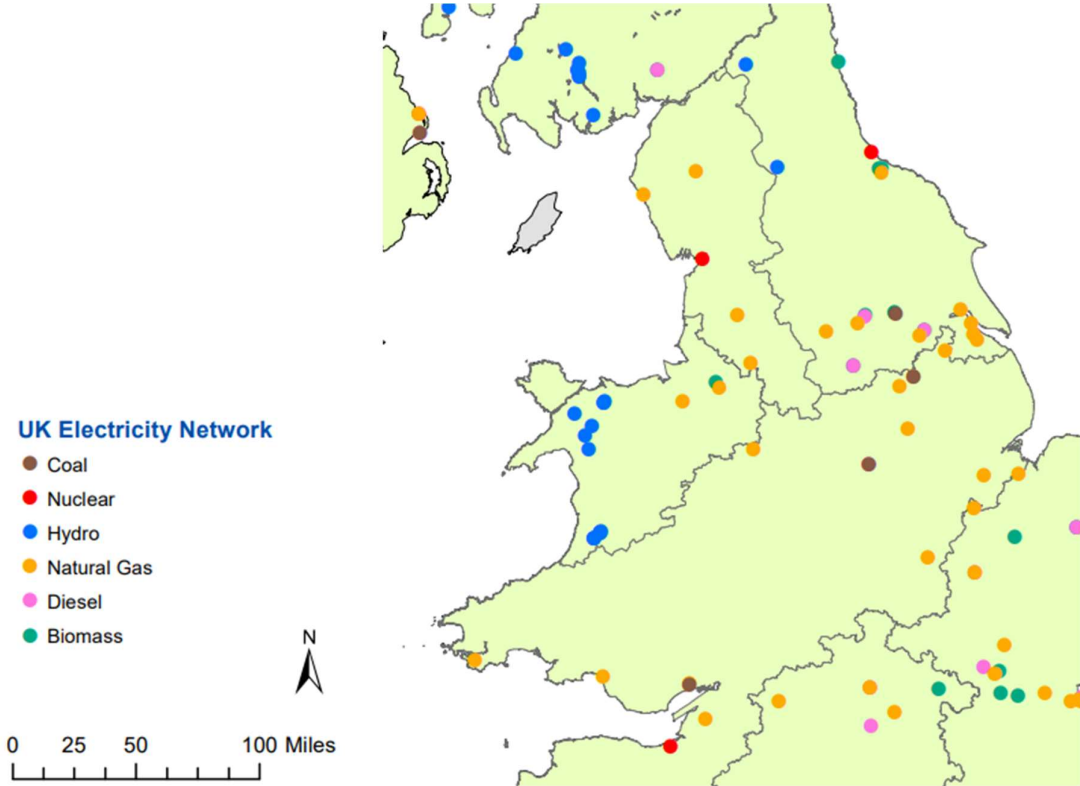


Figure 1 - Map of Major Power Producers across the region

Of the assets shown above, there are only 5 operating power generators greater than the 300MW capacity being considered in this report, and of those, only 3 could be considered dispatchable, i.e. run baseload but also respond to grid requirements in ramp up (and down);

Table 1 - Large scale dispatchable power generators in the North West and north Wales Region, reproduced from (2)

Company Name	Station Name	Fuel	Type	Installed Capacity (MW)	Year of commission or year generation began
ESB	Carrington	Natural Gas	CCGT	910.0	2016
Intergen	Rocksavage	Natural Gas	CCGT	810.0	1998
Uniper UK	Connahs Quay	Sour gas	CCGT	1,380.0	1996

As noted in DUKES 2020 (1), 2 dispatchable assets with a combined capacity of over 2GW have been decommissioned since 2018;

Table 2 - Large scale dispatchable power generators recently decommissioned in the North West and North Wales Region, reproduced from (2)

Site	Fuel	Status	Previous Capacity (MW)	New Capacity (MW)	Year of closure/opening,
Deeside	CCGT	Closed	498	0	2018
Fiddler's Ferry	Coal	Closed	1,510	0	2020

## 4. Technology Review

### 4.1 Introduction

The main source of dispatchable power generation today is natural gas-fired combined cycle gas turbine (CCGT) plant, but there are a number of potential technologies available for decarbonised grid-scale power generation in the future. Some of these are inherently carbon-free, or 'green' (such as use of hydrogen generated from renewable electricity) whilst others are decarbonised (such as plants employing post-combustion carbon capture).

Dispatchable generators are those that can start and stop, but also raise or lower their power output on command from the system operator or facility owner. But it is worth noting that some dispatchable generators are more flexible or faster in response than others. This report looks specifically at dispatchable assets, but only those which could also be continuously operable (i.e., storage is not considered).

A list of all potential future decarbonised dispatchable generation technologies is shown in Table 3.

*Table 3: Potential decarbonised generation technologies considered*

Technology	Brief Description	Max Known Size	TRL
Hydrogen Gas Turbines	Use of hydrogen within gas turbines – a zero-carbon fuel swap for today's natural gas plants.	385 MW (OCGT) 566 MW (CCGT)	5/8 [Note 1]
Natural Gas with Post-Combustion Carbon Capture Utilisation and Storage (CCUS)	Use of natural gas as a fuel with CO <sub>2</sub> removed from the flue gas after combustion, and then transporting and either storing or utilising the CO <sub>2</sub> .	N/A [Note 2]	8-9
Natural Gas with Pre-Combustion Carbon Capture Utilisation and Storage (CCUS)	Converting carbon species in the fuel to CO <sub>2</sub> , removing CO <sub>2</sub> prior to combustion, before transporting and either storing or utilising the CO <sub>2</sub> .	N/A [Note 3]	6
Oxyfuel Carbon Capture	Burning coal or biomass in pure oxygen and removing CO <sub>2</sub> from the flue gas after combustion.	32 MW	6
Bioenergy with CCUS (BECCS)	A biomass fuel combined with CCUS which results in negative emissions.	50 MW (3)	7 (3)
Biomass generation	Plant or animal material used as a fuel.	660 MW (3)	9 (3)
Small Modular Reactors (SMRs)	SMRs are nuclear power plants (up to 300MW) small enough to allow production line efficiency for cost reduction.	< 300 MW	6
Supercritical CO <sub>2</sub> Brayton Cycles	Turbine using supercritical CO <sub>2</sub> as the working fluid without a combustor. The combustor is replaced with an external source of heat which could be nuclear, solar, geothermal or Energy from Waste (EfW).	10 MW	7
Hydrogen Internal Combustion Engines (H2ICE)	Internal Combustion Engine using 100% H <sub>2</sub> fuel.	N/A – only demonstrated in transport applications.	1

Hydrogen Fuel Cells	Converts hydrogen and oxygen directly into electrical energy (and water).	50 MW	8
High Temperature Fuel Cells in Combined Cycles	High temperature fuel cells such as Molten Carbonate Fuel Cells (MCFCs) and Solid Oxide Fuel Cells (SOFCs) can act as topping cycles when combined with GTs and HRSGs.	59 MW	8
Smart Advanced Humid Air Turbine (Smart-AHAT)	Single cycle GTs that use a recuperator to improve efficiency.	40 MW	5
CCGT with Exhaust Gas Recirculation (EGR)	EGR can improve the efficiency of a CCGT with CCS by increasing CO <sub>2</sub> concentration making it is easier to implement CCS with smaller and cheaper capture plants.	100 kW	4
Allam Cycle	High pressure oxyfuel semi-closed cycle with a GT, recuperator, cooling and Air Separation Unit (ASU).	25 MW	7
Wind Driven Thermal Pumping	Uses wind to compress and heat gas in a close to isentropic process giving >10 hours thermal storage.	N/A	1
Ammonia Gas Turbines	Use of ammonia within gas turbines – a zero-carbon fuel swap for today's natural gas plants.	40 MW	4

Note 1: For H<sub>2</sub> GTs, TRL = 5 for dry low emissions/dry low NO<sub>x</sub> (DLE/DLN) combustion systems, TRL = 8 for diffusion combustion systems

Note 2: The Bellingham CCGT power plant captured CO<sub>2</sub> from a 40 MW slipstream from 1991 until 2005. For coal-fired generation, the largest post-combustion capture project is the Petra Nova plant which removes CO<sub>2</sub> from a 240 MW<sub>e</sub> slipstream.

Note 3: There are IGCC plants in operation although none currently perform carbon capture.

The TRL given in Table 3 is defined as follows (4):

- TRL 1** Exploratory research transitioning basic science into laboratory application.
- TRL 2** Bench-scale laboratory testing to validate basic concepts.
- TRL 3** Subsystem or component development refined.
- TRL 4** Subsystem or component validation in simulated real-world environment.
- TRL 5** Early system feasibility demonstrated in laboratory or limited field application.
- TRL 6** Early field demonstration and system refinements completed.
- TRL 7** Complete system prototype demonstration in an operational environment.
- TRL 8** Early commercial deployment (serial Nos. 1, 2, etc.).
- TRL 9** Wide-scale commercial deployment.

In this case, grid-scale is defined as an output of at least 300 MW which narrows the technology choices down to hydrogen turbines, gas with post-combustion CCUS, BECCS and biomass generation. The other technologies will be discussed briefly in Section 4.6 as future advances may bring them to grid-scale.

A number of published scenarios for the UK future energy system were reviewed to further inform which technologies are considered to have a dispatchable role in the future. The technologies identified in these studies as potentially viable are highlighted in green in Table 4.

Table 4: Low Carbon Dispatchable Power Technologies

	Climate Change Committee, The Sixth Carbon Budget (5)	National Grid Future Energy Scenarios (6)	BEIS Energy and Emissions Projections (7)	National Infrastructure Commission (8)
<b>Hydrogen Turbines</b>				
<b>Gas with Post-Combustion Carbon Capture Utilisation and Storage (CCUS)</b>		Not cost efficient in comparison to hydrogen turbines		But could be displaced by hydrogen turbines
<b>Bioenergy with CCUS (BECCS)</b>		More likely to operate at base load	Insufficient biomass anticipated	More likely to operate at base load
<b>Biomass Generation</b>	Limited supplies more likely to be used for BECCS or as a fuel in other sectors		Insufficient biomass anticipated	Limited supplies more likely to be used for BECCS

According to the National Grid, while BECCS is able to provide flexibility in a dispatchable manner, it is unlikely to be run as such (6). As BECCS provides negative carbon emissions, it is more likely to operate as baseload generation due to high predicted carbon prices (5) (8). The anticipated limited future biomass resource means it is unlikely to play a large role in grid-scale generation without the benefits of negative emissions that can be achieved with CCUS (5) (7) (8).

Hence, the focus here will be on hydrogen GTs and natural gas GTs with post-combustion CCUS as the above references predict that these will be the low carbon dispatchable technologies most likely to be deployed. The current technology status, efficiency, flexibility, system requirements and forecasted costs for both technologies will be discussed and compared. A typical 400 MW Combined Cycle Gas Turbine (CCGT) will be considered as a basis.

## 4.2 Gas with Post-Combustion Carbon Capture, Storage and Utilisation

### 4.2.1 Technology Description

#### 4.2.1.1 Carbon Capture

In 2019, natural gas accounted for 40.6% of electricity generation in the UK at 131.9 TWh (9). For the UK to achieve its legally binding target of net zero emissions by 2050, whilst at the same time maintaining a reliable and secure electricity supply, CO<sub>2</sub> abatement of natural gas generation is required. .

There are two pathways for natural gas that could be followed for CO<sub>2</sub> abatement. The first is replacement of natural gas with zero/low carbon hydrogen. The second is the deployment of carbon capture, storage, and utilisation technology, where CO<sub>2</sub> produced from a point source is captured and stored or utilised so that there is no climate impact from it, or at least it is largely reduced. According to the 2020 Future Energy Scenarios by National Grid, CCUS is required for all UK net zero scenarios across industrial and commercial sectors, including the power generation industry (6). There are currently no operational CCUS facilities in the UK, although there are some currently in development.

Carbon dioxide can be captured via three main approaches from industrial processes:

- Pre-combustion capture - where carbon is removed from the fuel prior to its use.
- Post-combustion capture - where CO<sub>2</sub> is removed from flue gases following combustion.
- Oxyfuel - where fuel is combusted in pure oxygen diluted with a recycled proportion of the flue gas, rather than air, to produce a flue gas that is rich in CO<sub>2</sub> and, following some purification, can be transported for storage or utilisation directly.

The simplified process schemes of these approaches to power generation with carbon capture are outlined below in Figure 2.

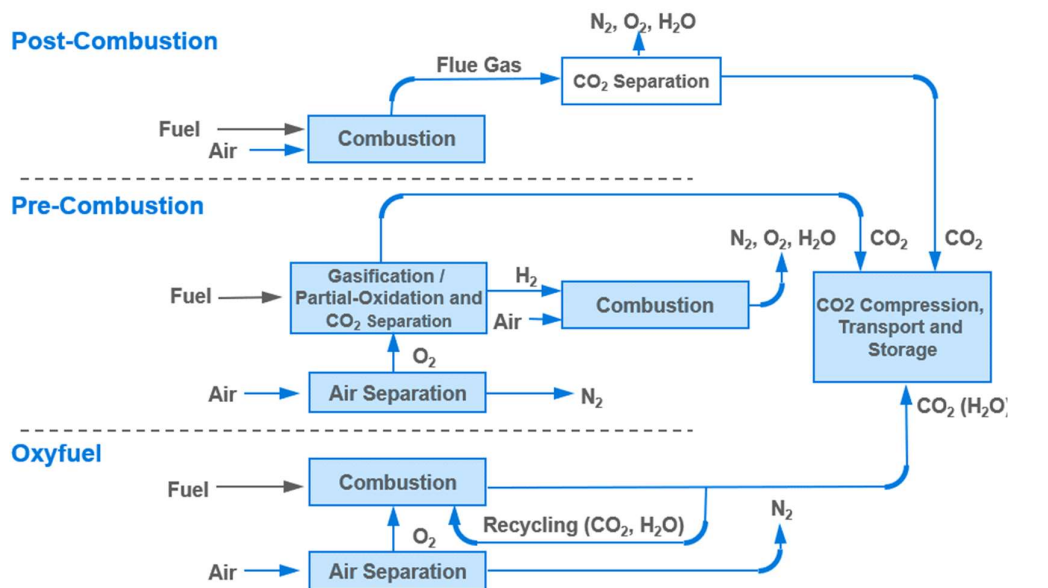


Figure 2: Process schematics for carbon capture options

As discussed above, the focus here is on post-combustion capture. Pre-combustion capture and oxyfuel will be discussed in Section 4.6.

#### 4.2.1.2 Post-Combustion Capture

The generic post-combustion capture (PCC) scheme includes the following main process stages:

- Sulphur oxides removal and flue gas cooling
- CO<sub>2</sub> absorption
- Solvent recovery
- CO<sub>2</sub> regeneration
- CO<sub>2</sub> product compression
- Amine reclaiming

This generic process scheme is displayed in Figure 3.

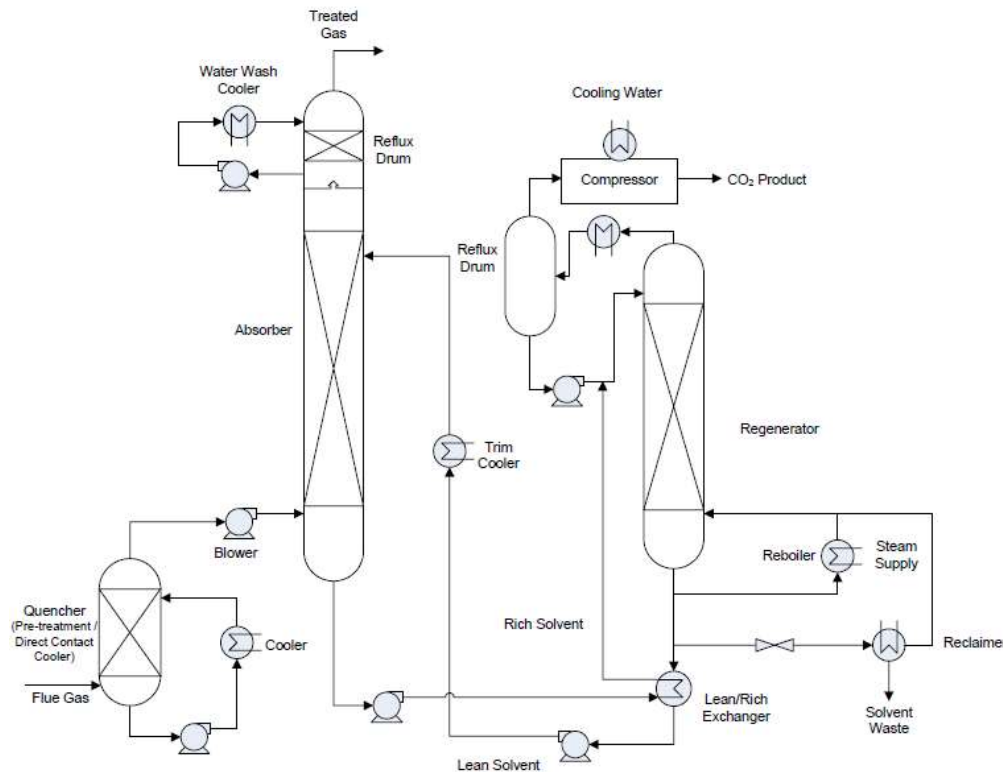


Figure 3: Key components of the post-combustion capture process

Hot flue gas exiting a heat recovery steam generator (HRSG) after fuel combustion enters a direct contact cooler (DCC) where it is cooled below its dew point. Since the amine absorption reaction is exothermic, the reaction is promoted by lower temperatures. Also, by cooling below the dew point, the concentration of residual acid gases such as sulphur oxides can be reduced to ppm levels. The cooled flue gas then enters the bottom of an absorption column where it flows upwards through structured packing where it is contacted counter-currently with a lean amine solvent such as monoethanolamine (MEA). CO<sub>2</sub> is selectively absorbed from the flue gas into the solvent, with CO<sub>2</sub> removal from the flue gas typically in the 85-90%+ range.

The treated flue gas leaves the absorber through a washing section to recover vapour phase amine emissions and degradation products, and is released to the atmosphere via the stack. The CO<sub>2</sub> rich solution is pumped to the top of a stripper column and flows downwards through structured packing where it is contacted with process steam which drives the CO<sub>2</sub> out of solution. The now lean solvent is then cooled before re-entering the absorption column to complete a continuous cycle.

The amine solvent often reacts with flue gas constituents in the absorber and undergoes a slow degradation under high temperatures in the stripper to form heat stable salts (HSS) that cannot be

regenerated. This necessitates a reclaimer, where the removal of HSS occurs by reaction with diluted sodium hydroxide or sodium carbonate solution. This reclaimer unit is typically operated intermittently and over prolonged periods of time. During operation this increases power consumption and produces a waste stream that must be processed safely.

The recovered CO<sub>2</sub> enters the wash section of the column, where vapourised and entrained solvent can be recovered, before it is compressed in multiple stages with interstage coolers and knockout vessels to remove condensed water. The high purity CO<sub>2</sub> product is then transported to suitable storage sites or utilisation facilities.

PCC is an end-of-pipe solution, so can be retrofitted to existing coal-fired and gas-fired plants without extensive modification of the power plant and can also be applied flexibly to new build applications. The elements of this process are also well proven in industrial applications, and the commercial deployment of the process at Boundary Dam and Petra Nova have aided its understanding and feasibility. However, due to the requirement for large quantities of steam from the HRSG for solvent reclaiming the overall plant efficiency penalty is high. Amine degradation also increases costs and adds a potential waste disposal burden, and is currently poorly understood.

#### 4.2.1.3 *Transport and Storage*

Once CO<sub>2</sub> is captured and compressed at the power plant, it must be transported to a suitable storage site. CO<sub>2</sub> is typically transported via pipeline, and then injected into a storage site. CO<sub>2</sub> may also be pressurised and shipped to storage locations, which may become more feasible at longer distances, or transported by truck or train although in much lower quantities. Currently the most well-established locations for storing CO<sub>2</sub> are:

1. Depleted oil or gas reservoirs
2. Deep unmined coal seams
3. Saline formations

Storage in depleted oil or gas reservoirs is straightforward in principle since a pipeline network already exists, although their suitability for CO<sub>2</sub> must be confirmed, and the reservoirs are well understood. At depths greater than 800 m CO<sub>2</sub> has the density of a liquid meaning that vast quantities can be stored. Over time, CO<sub>2</sub> may react with alkaline rocks to form solid carbonate deposits. An example is the Sleipner field in Norway, which stores approximately 1 million tonnes of CO<sub>2</sub> per year and has been in operation since 1996 (10).

In deep unmined coal seams CO<sub>2</sub> can be adsorbed onto the surface of coal. However, the technical feasibility of this depends on the permeability of the coal bed. CO<sub>2</sub> has a greater affinity for adsorption onto coal than methane, so in the process of sequestering CO<sub>2</sub> methane can be recovered; this is known as enhanced coal bed methane recovery. While the sale of the methane can be used to offset some of the costs of storage, this could potentially negate some of the decarbonisation accomplished by CCS.

Saline aquifers contain highly mineralised brines, and have so far been considered to have no use. Deep saline aquifers are estimated to have significantly larger storage capacity than oil and gas reservoirs, although relatively little is known about them compared with storage in depleted hydrocarbon reservoirs (11). In these aquifers, some CO<sub>2</sub> can dissolve into solution in a process known as “dissolution storage” and descend to the bottom of the aquifer. An example is Endurance, which is a well-understood mature saline aquifer situated in the North Sea that has been identified as a future CO<sub>2</sub> storage site for CO<sub>2</sub> produced from UK industrial point sources.

While CO<sub>2</sub> leakage is possible from any of these types of storage locations, one recent study has estimated that over 98% of injected CO<sub>2</sub> will remain stored in the subsurface for over 10,000 years (12).

#### 4.2.1.4 Utilisation

Carbon capture and utilisation may help to offset some of the cost of carbon capture by using the CO<sub>2</sub> to create value-added products while avoiding carbon emissions. However, CO<sub>2</sub> utilisation will only be able to address a small proportion of the total reduction in CO<sub>2</sub> emissions required to reach climate targets (13).

Enhanced oil recovery (EOR) is a method of extracting crude oil from an oil field that cannot be extracted otherwise. In a process known as “miscible flooding”, CO<sub>2</sub> is injected into the oil field and displaces oil by increasing reservoir pressure and also reducing crude oil viscosity meaning crude oil is more effectively swept into the production well. This has been shown to increase oil output by 5-40% (14). An example is Boundary Dam Power Station in Saskatchewan, Canada owned by SaskPower. A PCC unit attached to its lignite-fired Unit #3 can capture 1 million tonnes/year of CO<sub>2</sub> at a capture rate of 90%. The majority of this CO<sub>2</sub> is then sold to be utilised for EOR in the Weyburn Oil Field. A key downside of this method of utilisation is that it contributes indirectly to further CO<sub>2</sub> emissions from crude oil.

CO<sub>2</sub> captured from point sources such as power plants can, if its purity is high enough, be transported and used in the food and beverage industry in processes such as the decaffeination of coffee beans, the carbonation of beer and soft drinks, and refrigeration during transportation.

Other options for utilisation are wide-ranging and vary in the quantity of CO<sub>2</sub> required, which may be insignificant compared to the quantities of CO<sub>2</sub> that could be captured from a CCGT. This includes:

- Horticulture
- Water treatment
- Chemical synthesis
- Urea production
- Pharmaceutical processes
- Inerting
- Synthetic fuel manufacture
- Mineralisation
- Power generation (CO<sub>2</sub> as a working fluid, e.g., Allam cycle)
- Pulp and paper processing

This report considers only the capture plant associated with power generation technologies. Transport, storage and possible utilisation is being developed through separate workstreams within the NZNW Cluster Plan.

### 4.2.2 Current Technology Status

#### 4.2.2.1 OEM Status

The current PCC solutions offered by OEMs are generally variations of the generic PCC process described above. Nonetheless, most of the OEMs use different solvents, and may have alterations of process features such as thermal and water integration.

Several problems have been encountered with amine solvents. These include thermal and oxidative degradation which not only result in the loss of the amine solvent, which therefore requires replacement, but also in the build-up of degradation products in the system which require removal via reclaiming. Amine solvents are also prone to reacting with any remaining acid gases such as SO<sub>2</sub>, SO<sub>3</sub> and NO<sub>2</sub> in the flue gas entering the capture plant. Another factor is the corrosion of the plant internals by some amine solutions, which affects material selection. As a result, a lot of work has been carried out around the world investigating these operating issues in order to understand the fundamental causes so that a more optimal solution can be achieved.

There are many factors to consider for choosing solvents such as reaction rate, solvent capacity, physical characteristics of the solvent, energy required for stripping, solvent management issues, and the cost of the solvent. Therefore, a range of solvents or even a mixture can be considered for CO<sub>2</sub> capture.

The current focus of carbon capture OEMs is the reduction of efficiency penalties and plant costs as well as increasing the target CO<sub>2</sub> capture rate. While 90% capture of CO<sub>2</sub> is the current benchmark for developers, companies such as Bechtel are currently assessing economical solutions to increase the capture rate to 95% and above (15). The technical feasibility of solvent storage has been confirmed by OEMs such as Aker Clean Carbon, Alstom (now GE) and Mitsubishi Heavy Industries - this concept is further described in Section 4.2.7 (16). Exhaust gas recirculation (EGR) has also been proposed as a method of reducing the efficiency impact of the capture plant by increasing the concentration of CO<sub>2</sub> in the flue gas. This would require modification from the GT manufacturer rather than carbon capture OEMs, therefore in this case a whole plant approach would be required to deploy this technology. An outline of some of the main commercial CCS process developers and their solvents is shown in Table 5.

*Table 5: Commercial process developers and solvents*

<b>Amine Process/Solvent</b>	<b>Developer</b>
Fluor Daniel Econamine FG+ process	Fluor
Cansolv® CO <sub>2</sub> Capture System	Shell - Cansolv Technologies Inc.
Kansai-Mitsubishi proprietary CO <sub>2</sub> recovery process (KM-CDR) KS-1	Mitsubishi Heavy Industries (MHI) Ltd and Kansai Electric Power Co. Ltd
BASF OASE	Linde
UCARSOL™ AP 800 Series	Dow Chemical Company
Cansolv	Shell/Technip
Pureenergy 1000	HTC Pureenergy
Just Catch™	Aker Carbon Capture
CDRMax® Process, APBS-CDRMax® solvent	Carbon Clean
C-Capture amine-free solvent	C-Capture

#### 4.2.2.2 *Current Projects*

##### 4.2.2.2.1 *United Kingdom (UK)*

While there are currently no operational CCGT plants with CCS in the UK, there are some proposals that have been awarded funding within the UK Research and Innovation's (UKRI) £171 million Industrial Challenge Strategy Fund (ISCF) and by the Department of Business, Energy and Industrial Strategy (BEIS).

Within the North West industrial cluster, a carbon capture and utilisation plant by Pentair Union Engineering for Tata Chemicals Europe has been awarded £4.2 million in grant funding from BEIS. The 400 MW<sub>th</sub>, 96 MW<sub>e</sub> combined heat and power plant (CHP) will capture up to 40,000 tonnes per year of CO<sub>2</sub> to be utilised for sodium bicarbonate manufacturing. This project is set to commence operations by the end of 2021.

£12.7 million has been awarded to the Humber Zero project, which includes a proposal for a retrofitted PCC plant to two existing gas turbines and auxiliary boilers at VPI's 1.2 GW Combined Heat and Power (CHP) Plant at Immingham. The Humber Zero project, of which the VPI development is a part, plans to progress into FEED in 2021, and expects to remove 8 MtCO<sub>2</sub> per annum by the mid-2020s, potentially

increasing to 40 MtCO<sub>2</sub> per annum by 2040 (17). This will be stored offshore in depleted gas fields and saline aquifers.

The Zero Carbon Humber Partnership has been awarded £21.5 million from the ISCF, which includes in its scope the development of Keadby 3 Power Station near Scunthorpe. This new-build 910 MW power station is being developed by SSE Thermal and Equinor and will use natural gas as a fuel with a post-combustion carbon capture unit to remove CO<sub>2</sub> at a rate of at least 90%. This plant could be operational by the mid-2020s, with a target to offset at least 1.5 MtCO<sub>2</sub> by 2030 (18). As part of the Northern Endurance Partnership between Net Zero Teesside and Zero Carbon Humber, captured CO<sub>2</sub> will be transported to the Endurance saline aquifer.

In addition to the development above, Net Zero Teesside (onshore) has been awarded £28 million from the ISCF. Within its project scope is a power station with up to three CCGT units each with a generating capacity of approximately 700 MW following 90% CO<sub>2</sub> capture (19).

The NECCUS programme is an alliance of Scottish industry which has been awarded £20 million for onshore net zero infrastructure and £11.4 million for offshore net zero infrastructure. A portion of this funding will be used to develop a new 900 MW gas-fired power station at Peterhead fitted with carbon capture technology led by SSE Thermal and Equinor which aims to be in operation by 2026. The target is to capture 1.5 MtCO<sub>2</sub> annually, and is similar in scale to the Keadby 3 development of SSE and Equinor, which represents 15% of the UK Government's target to capture 10 MtCO<sub>2</sub> annually by 2030, for storage at the Acorn CO<sub>2</sub> storage site beneath the North Sea. A previous proposal for a CCS plant at Peterhead was scrapped in 2015 after the FEED stage. This previous proposal included the development of a retrofit carbon capture plant to the existing gas-fired facility at the site.

#### 4.2.2.2.2 *International*

Like the UK, there are yet to be any operational natural gas-fired power stations with PCC, although coal with PCC has been demonstrated commercially in a small number of projects. While the fuel sources are very distinct from each other, the carbon capture process following combustion are broadly similar. The key differences are that the flue gas from a coal-fired power plant has a much higher CO<sub>2</sub> concentration than the flue gas from a gas-fired power plant, which affects equipment sizing and therefore CAPEX. Coal combustion flue gas may require a more thorough desulphurisation step.

The world's first commercial scale post-combustion coal-fired CCS project began in 2014 at the SaskPower Boundary Dam Power Station in Saskatchewan, Canada. A post-combustion capture unit was retrofitted to Unit 3 and is capable of capturing over one million tonnes of CO<sub>2</sub> per year, equivalent to a 90% CO<sub>2</sub> capture rate for the 139 MW coal-fired unit (20). The captured CO<sub>2</sub> is then compressed and transported via pipeline to the Weyburn Oil Field where it is used for EOR. As operating experience has grown the reliability of the capture plant has improved, although significant issues with solvent degradation have been encountered.

#### 4.2.3.2 *Feasibility*

##### 4.2.3.2.1 *New Build*

As shown in Section 4.2.2, new build natural gas-fired CCGT plants with post-combustion carbon capture are currently technically feasible and capture plant can be procured both as a retrofit measure to existing assets, or as part of new developments. While this has not yet been demonstrated commercially, all the plant elements are reasonably well established in industry. Gas-fired power stations are a primary source of power worldwide, and carbon capture technology has been utilised in refineries for decades to remove CO<sub>2</sub>. However, very few of these examples demonstrate the storage and transport or utilisation aspects, with only a handful of commercial projects having been operational.

The Technology Readiness Level of CCGT power plants is TRL 9, and amine solvent processes provided by vendors such as Fluor, Shell and Dow are also TRL 8-9 due to wide use in fertiliser, soda ash and natural gas processing plants, as well as in carbon capture projects such as the Boundary Dam project (21). However, it should be noted that whilst large applications exist on coal fired power plant, and investigations are continuing for gas fired CCGTs, there are currently no large CCGT plant equipped with the technology.

A key challenge with applying PCC processes to CCGT plants is the low CO<sub>2</sub> concentration in the flue gas. A conventional CCGT is considered to have a CO<sub>2</sub> concentration of approximately 3-4 vol% in the flue gas, compared to 12-14 vol% in the flue gas for a coal-fired power plant (22). This means that larger absorbers are required in comparison to coal power plants with PCC and also a higher volume of flue gas must be processed for the same quantity of CO<sub>2</sub> captured. If comparing on the basis of CO<sub>2</sub> emitted per MWh of power exported, the difference between the two cases is less, although the CCGT case still suffers from a lower CO<sub>2</sub> concentration and a higher flue gas flow rate. This has a large impact on cost, which is further exacerbated by the amine degradation arising from the associated high oxygen content entering the scrubber system. An approach to reduce this cost impact is to recirculate a portion of the flue gas to the inlet of the gas turbine. This increases the concentration of CO<sub>2</sub> in the flue gas, and reduces the relative size of the capture plant, as well as reducing the driving force for oxidative degradation of the solvent. For a CCGT with Exhaust Gas Recirculation (EGR) coupled with carbon capture a TRL of 7 is assumed, with the lower TRL being associated primarily with the application of the EGR system to a gas turbine.

An additional challenge is the availability of a suitable storage site near to the capture plant, assuming that storage rather than utilisation is desired. Proximity to a suitable storage site such as a depleted oil or gas reservoir will have a large effect on CAPEX and OPEX due to the reduced cost of the associated CO<sub>2</sub> transport and storage, which could in turn impact project feasibility.

#### 4.2.3.2.2 *Retrofit*

A natural gas-fired power station retrofitted with a PCC unit would contain the same elements as a new-build plant, so would therefore also have the same TRL.

The main challenges with retrofit would likely vary significantly on a site-by-site basis. The additional plant footprint for a PCC unit may have an impact on the capture process solution, for example by affecting unit sizing or the size of the flue gas stream that can be treated by the capture plant. Additionally, existing power plant tie-ins may also affect the design and operation of the capture plant. The imposition of a capture plant will also increase the cooling water demand of a gas power plant, which could trigger a new water abstraction permit application for the retrofitted site subject to review by the EA.

Additionally, where the intention is to include measures such as EGR, the availability of this technique as a retrofit package to an existing GT may not be as high as for new build units.

#### 4.2.4 Efficiency

The addition of a PCC unit imposes a parasitic power demand on the existing power plant and thus lowers its efficiency. In a technical advisory report for BEIS by Uniper Technologies, it was estimated that following CCS retrofit the efficiency of a generic unabated CCGT fell from 59.8% to 52.6% - a 7.2%pt decrease (23).

Kather et al. (24) conducted an in-depth study into the impact of adding PCC to an existing CCGT, with the following units as a reference:

- Gas Turbine: ALSTOM GT26 - 2 units
- HRSG: Reheat, Horizontal HRSG - 2 units
- Steam Turbine: Condensing. Reheat - 1 unit
- Cooling System: Water cooling with natural draft cooling tower

The key performance data of the reference case are:

• Gross output [MW]	890
• Net output in [MW]	876
• Net efficiency [%]	59.2
• Gas turbine power at generator [MW]	278
• Efficiency of the gas turbine [%]	37.6

The power plant was modelled with cycle calculation software utilising a heat balance derived from THERMOFLOW software, while the CO<sub>2</sub> separation plant was modelled using Aspen Plus Software. An aqueous solution with a mass fraction of 30% MEA was used as a solvent, and the captured CO<sub>2</sub> was compressed to 110 bar to transport the CO<sub>2</sub> to the storage location.

The findings were that if carbon capture is applied to the plant, the following loss sources contribute to the net efficiency loss for the process:

• steam extraction for regeneration of MEA	4.55%pt
• CO <sub>2</sub> compressors	1.58%pt
• Electrical consumers in carbon capture plant	1.54%pt
• Additional cooling water pumps	0.21%pt

In total this is a net efficiency loss of 7.88%pt for the CCGT with a capture rate of 90%.

One option to reduce the energy consumption of the CO<sub>2</sub> separation plant is to increase CO<sub>2</sub> content in the flue gas by exhaust gas recirculation (EGR, or flue gas recirculation (FGR)). Here, part of the exhaust gas would be routed back to the gas turbine compressor inlet instead of to the CO<sub>2</sub> separation plant. As a result, higher CO<sub>2</sub> concentrations can be achieved in the exhaust gas, which facilitates the absorption process. Simultaneously the exhaust gas mass flow is reduced because less fresh air and thus less inert nitrogen must be processed. A recirculation rate of approximately 50% is achievable; higher recirculation rates would result in under-stoichiometric combustion in the second combustion chamber. By applying EGR the net efficiency loss of carbon capture would be reduced to 7.28%pt.

#### 4.2.5 Emissions

A key issue in the use of carbon capture with amine-based solvents is the air emissions of substances such as amines, ammonia, carboxylic acids, nitrosamines, nitramines and amides. These species may form due to solvent degradation or the reaction of the amine or its decomposition products with SO<sub>2</sub> and NO<sub>2</sub>. Any of these species has the potential to be emitted to air in the treated flue gas if appropriate control measures are not utilised, and therefore it is essential that these substances are identified and characterised and that their environmental impact is investigated to mitigate emissions to an acceptable level. Overall, however, this should not be an insurmountable challenge.

The extent of amine degradation will vary depending on the amine chosen and the process conditions. Amine solvent degradation is catalysed by high temperatures, elevated oxygen concentrations in the flue gas, and the presence of trace metals potentially released into the solvent due to corrosion of process equipment. Therefore, appropriate solvent choice, plant design and careful operation of the capture plant is imperative to minimise degradation and hence the potential emissions from the PCC plant. Additionally, the volatility and environmental impact of the amine itself should also be considered.

In the atmosphere, amines may also undergo reactions to form other species. The atmospheric behaviour of amines is not well understood, and research is currently being carried out in this area. Amine volatility will significantly affect the concentration of amine in the flue gas leaving the absorber. Amine volatility in solution will not necessarily follow the same trend as the relative volatility of pure amines and will vary as the concentration of the amine in the solution changes. Other amines may also be formed during the capture process as a result of solvent degradation, although these are expected to have lower molecular weights than the selected amine as they are likely to be formed from fragments of the main amine.

Ammonia may be formed within the capture process as a product of amine degradation. Therefore ammonia production will be low for stable amines and higher for amines that are more prone to degradation, such as MEA. Since ammonia has a high volatility and relatively low solubility in water with a pH value of 9, a conventional wash section at the top of the absorber is easily saturated and does not remove any ammonia. If the rate of ammonia formation is high then the emission of ammonia is also high unless there is a second washing stage, such as an acid wash. In this case, additional flue gas washing technologies may be required to reduce emissions to an acceptable level.

Nitrosamines are a class of both synthetic and naturally occurring compounds, typically liquids, oils or volatile solids, with the general formula  $R_2N-N=O$ . Most nitrosamines are known to be carcinogenic. Nitrosamines can be formed in the PCC process by the reaction of amines with  $NO_2$  present in the flue gas. Only secondary amines can form stable nitrosamines. Primary amines can form nitrosamines in solution, although they are unstable, while tertiary amines cannot form nitrosamines. Selection of a primary or tertiary amine for the PCC solvent would, therefore, significantly reduce the chance of nitrosamine formation. These amines can, however, degrade to form secondary amines and so there may still be a route to stable nitrosamine formation. The concentrations of any secondary amines produced as a result of degradation would, however, be relatively low.

In general, there is still a lack of reliable data in relation to the full range of nitrosamine species that may be formed, their relative yields, and the rates of their formation. Consequentially, although the environmental significance of nitrosamine emissions is considered to be low, it is down to individual plant developers to make a convincing case to their regulators when making applications for environmental permits.

Nitramines are a group of compounds with the general formula,  $R_2-N-NO_2$ . They can be formed in the PCC process by the reaction of amines with  $NO_x$  in the flue gas, through a similar pathway to that of the formation of nitrosamines. Nitramines are mutagenic and carcinogenic, although they appear to be considerably less carcinogenic than nitrosamines (25).

Aldehydes are a group of compounds containing a terminal carbonyl group with the general formula,  $RCH=O$ . Within the PCC process aldehydes such as acetaldehyde and formaldehyde can be formed as a result of amine degradation. Aldehydes are also major products in the photooxidation of hydrocarbons, and in the reactions of hydrocarbons with ozone, oxygen atoms, or free radicals. Amine emissions from the PCC process could, therefore, result in the formation of aldehydes in the atmosphere. Formaldehyde and acrolein have been specifically identified in urban atmospheres. These materials are thought to contribute to the odour and eye irritation produced by photochemical smog.

An important environmental issue with respect to post-combustion capture is the generation of degraded amine waste that has to be mitigated or disposed of properly. Capture solvent can degrade due to the presence of other gaseous species present in the flue gas such as  $CO_2$ ,  $SO_x$ ,  $NO_x$ ,  $O_2$ , halogenated compounds and other impurities. Degradation products formed by amine-based solvents can include heat stable salts (HSS), non-volatile organic compounds and suspended solids. In a gas turbine-based power plant, concentrations of acid gas species would be expected to be low, but conversely the oxygen content is relatively high. Typically, these degradation products and heat stable salts exhibit corrosive properties and reduce solvent  $CO_2$  absorption rates. Therefore, reclaiming is required to prohibit accumulation of these degradation products in unacceptably high concentrations in the capture solvent.

Generally, a stream of amine is sent to a reclaiming system, where part of the solvent is reclaimed and returned to the capture process. The most commonly implemented reclaiming technique involves thermal reclaiming. In this process, amine vapours recovered from distillation are sent back to the  $CO_2$  capture unit. The waste sludge remaining in the reclaimer is periodically discharged to prevent any accumulation of these impurities in the reclaimer. Thermal reclaiming is typically only in operation for a fraction of the time of capture plant operation. Using MEA as a process solvent in a natural gas capture plant yields approximately 1.2 kg/MWh of generated reclaimer waste (26). The economic effects of regeneration temperature, inlet oxygen concentration in the flue gas and level of corrosion within the

system are minor in comparison to the effect of the concentration of  $\text{NO}_x$  and  $\text{SO}_2$  in the inlet flue gas. Therefore, minimising the concentrations of  $\text{NO}_x$  and  $\text{SO}_2$  in the inlet flue gas to the capture system appears to be the most effective way to minimise the concentration of HSS in the amine solvent, and hence reducing the requirements and waste disposal costs of the reclaiming system. However, as noted earlier, the low concentrations of  $\text{NO}_x$  and  $\text{SO}_2$  in the flue gas means that, in practice, the dominant degradation route may be oxidative.

Additionally, while  $\text{CO}_2$  emissions are significantly reduced when carbon capture is applied, there are still appreciable releases of  $\text{CO}_2$  to the atmosphere.  $\text{CO}_2$  is a greenhouse gas which contributes to climate change and global warming. While 90% capture is ubiquitous in carbon capture literature, studies have found that capture rates up to 95% and above are feasible without significant further increases in cost (27).

#### 4.2.6 Flexibility and Operational Constraints

A natural gas-fired power plant fitted with CCUS technology will be less flexible than one without. This is a key challenge in the power generation context where exported power will be required to ramp up and down to meet the instantaneous change in production from intermittent and non-dispatchable renewables. Nonetheless, the ability for a power plant with CCS to be dispatched to balance other generation sources is a key advantage it has in contributing to a resilient and secure future power network.

A key flexibility constraint for a CCGT plant with PCC is limited  $\text{CO}_2$  compressor turndown -  $\text{CO}_2$  compressors may only operate down to 70% load. This may require management through recirculation of compressed  $\text{CO}_2$ , which increases power demand and reduces overall efficiency, or alternatively through the use of multiple compression trains, which will have a CAPEX implication.

Solvent storage has the potential for improving the flexibility and economics of the power plant. A rich/lean solvent storage system stores  $\text{CO}_2$  rich solvent during periods when electricity demand (and profitability) is high while operating the solvent regeneration at part load and continuously capturing  $\text{CO}_2$  from the flue gases in the absorber. Stored solvent is then regenerated, and  $\text{CO}_2$  is compressed during low electricity demand periods. This can reduce the energy penalty of the PCC unit by decreasing the amount of steam extracted from the steam cycle and reducing the  $\text{CO}_2$  compressor duty. Additionally, solvent storage can be designed to reduce reboiler size; by modifying the peak load storage percentages, it is possible to ensure that the amount of stored solvent to be regenerated at any time will be lower than the amount of solvent circulating during 100% load on the capture unit (27).

A major factor for the operation of the capture plant is the availability of steam for solvent regeneration. Steam must be extracted from the CCGT steam cycle and piped to the reboiler of the solvent regenerator column. This represents a significant quantity of energy that is not available to generate electricity via the steam turbine. For a  $\text{CO}_2$  capture train for a retrofitted PCC unit this would be optimised as far as possible, within the constraints placed by the existing equipment. This could be further optimised, in comparison to retrofits, in design for a new-build natural gas plant with CCS.

The ramp rate of a power plant fitted with carbon capture will be a function of the investment made in, for example, amine buffer storage and steam supplies. It will also depend on whether during the start-up and shutdown process there is a source of steam available for solvent regeneration (such as from a neighbouring unit or facility). However, one scenario is that the power plant itself will ramp at a similar rate to an unabated unit, with the carbon capture plant following. This will see load unaffected, but capture of  $\text{CO}_2$  may not be able to achieve high rates, due to a lack of  $\text{CO}_2$  lean solvent being available to contact with gas in the absorber. This can be partially mitigated by having sufficient lean amine storage that can be drawn from to ensure enough lean solvent is available during the initial load ramp. Following start-up, it would be expected that the stripper reboiler steam supply would be sufficient to have warmed the column up and achieve temperatures sufficient for solvent regeneration. Until this point is reached, there must also be some rich amine storage, otherwise  $\text{CO}_2$  loading of the recirculating solvent will gradually increase, though this may be acceptable to a certain extent. However, almost

inevitably, there will be some reduction in capture efficiency during start-up and, depending on the operating philosophy of the capture plant, during shut-down. However, for dispatchable plant, this impact can be minimised through measures such as ensuring adequate lean and rich amine storage is available. There may also be a reduction in capture efficiency during load ramps, since there will be a delay between the change in flue gas flow and the change in solvent flows.

#### 4.2.7 Requirements

A natural gas power plant fitted with PCC will have the same boundary limit utility connections as a CCGT, namely: fuel supply, electrical import, electrical export, water supply and water discharge, with the addition of CO<sub>2</sub> export and reclaimer waste export.

For a 400 MW<sub>e</sub> CCGT with PCC the works power demand will be higher compared to the base 400 MW<sub>e</sub> CCGT case due to the additional power demands of the capture plant, while cooling water import will also increase due to the extra cooling duty required for carbon capture. To satisfy the heating requirements of the stripper reboiler, intermediate or low pressure steam must be sourced either from the power plant or from a dedicated steam generation system. The CO<sub>2</sub> compression and conditioning stage also requires additional power and cooling water supply. This typically takes place in a multistage compression process with interstage cooling to compress the CO<sub>2</sub> to its desired export pressure and also to condense out and remove water and other impurities in knockout drums. From the Levelised Cost of Electricity (LCOE) calculations in Section 4.4, it is estimated that for a First of a Kind (FOAK) CCGT with CCS plant, 0.34 t CO<sub>2</sub>/MWh<sub>e</sub> would be exported from the plant to the transport and storage network. Process water produced by PCC units is typically of a high quality and can be integrated for re-use within the capture plant, negating the need for significant further water treatment and discharge.

#### 4.2.8 Forecast Costs

##### 4.2.8.1 CAPEX

Uniper has previously analysed capture plant costs for BEIS using a number of different sources, and concluded that the CAPEX for a capture plant on a 1200 MW CCGT site would be £602m (23). Due to the 12% reduction in sent-out power with CCS, the output of this reference plant would be 1056 MW.

A 10% inflation value was used to convert this from the reported 2014 cost to a 2021 cost. This was then prorated to a 400 MW CCGT (352 MW sent-out power) using the six-tenths power rule (28) to give a total CAPEX of £342m. This is for the capture plant alone and in addition to the natural gas CCGT CAPEX of £312m discussed in Section 4.3.8.1.

This capture CAPEX is for a First of a Kind (FOAK) installation. For a Nth of a Kind (NOAK) installation a 30% CAPEX reduction (23) is anticipated; this would reduce the cost of the capture plant to £240m.

Using the proportional CAPEX contributions from the FEED study for Karsto (in Norway) (29), a typical breakdown of CAPEX for both FOAK and NOAK carbon capture on a 400 MW CCGT is shown in Table 6.

Table 6: Typical CAPEX of a 400 MW NG CCGT with CCS

CAPEX (£m)	FOAK	NOAK
400 MW CCGT	312	312
Capture Plant	342	240
Flue Gas Conditioning	21	15
CO <sub>2</sub> Absorption	56	39
Solvent Regeneration	28	20
CO <sub>2</sub> Compression and Conditioning	32	22
Utility System	27	19
Automation	16	11
Civil Structural Work	35	25
Electrical Work	57	40
Indirect Costs	70	49
<b>Total</b>	<b>654</b>	<b>552</b>

#### 4.2.8.2 OPEX

OPEX values are explored further in Section 4.4 including a full explanation of assumptions and sensitivities. The base case assumptions for an 85% load factor will be used here.

For Operations and Maintenance (O&M), typical values for a capture plant are £10,763/MW/year for fixed O&M and £0.98/MWh for variable O&M (23) accounting for a 5% increase in inflation from 2018 to 2021. This is in addition to the O&M cost of the CCGT itself, as discussed in Section 4.3.8.2.

The natural gas price is assumed to be £20.31/MWh in the FOAK case and £21.84/MWh in the NOAK case as discussed in Section 4.4. If the net plant outputs are kept constant, then slightly less fuel is required in the NOAK case as net load plant efficiency is anticipated to improve from 52.6% to 53.3% (23).

Natural gas combustion releases 56.1t CO<sub>2</sub>/TJ (30) and 90% capture is assumed. CO<sub>2</sub> transport and storage is treated as an operating cost and is assumed to take place via the proposed HyNet pipeline at a cost of £12/tonne of CO<sub>2</sub> captured (31). This can be considered part of the variable O&M costs.

For the 10% of the produced CO<sub>2</sub> that is not captured there will be a CO<sub>2</sub> cost under the UK Emissions Trading Scheme. This is discussed further in Section 4.4, with a carbon price of £42.66/tonne assumed in the base case.

Consequently, the typical OPEX for both FOAK and NOAK carbon capture on a 400 MW CCGT is shown in Table 7.

Table 7: Typical OPEX of a 400 MW NG CCGT with CCS

OPEX (£m/year)	FOAK	NOAK
Capture Fixed O&M	3.79	3.79
Capture Variable O&M	2.56	2.56
CCGT Fixed O&M	5.13	5.13
CCGT Variable O&M	4.67	4.67
Fuel Cost	101.20	107.40
CO <sub>2</sub> Cost	4.29	4.24
T&S Cost	10.87	10.73
<b>Total</b>	<b>132.51</b>	<b>138.50</b>

### 4.3 Hydrogen Gas Turbines

#### 4.3.1 Technology Description

For decades, power generation gas turbines (GTs) have mainly operated with carbon-based fossil fuels such as natural gas (NG). This trend remains the case globally and here in the UK, where in 2019 natural gas accounted for over 40% of total annual electricity generation (2). Hydrogen (H<sub>2</sub>) is therefore being considered as a replacement fuel for natural gas in an effort to decarbonise the UK’s gas-fired power generation capacity while also ensuring security of energy supply alongside increasing amounts of intermittent renewable generation capacity. However, the use of hydrogen for electricity generation globally is currently 0.2% of total generation (32), compared with natural gas which currently averages 30% of electricity generation for countries in the Organisation for Economic Co-Operation and Development (OECD) (33).

As a zero-carbon fuel, hydrogen to power (H<sub>2</sub>P) represents a form of “pre-combustion” power generation carbon reduction. This is in contrast to the “post-combustion” carbon reduction discussed in Section 4.2. When hydrogen burns in air within a gas turbine, the combustion process does not produce carbon dioxide (CO<sub>2</sub>), and instead the exhaust gases contain mainly nitrogen (N<sub>2</sub>) and water (H<sub>2</sub>O). Any CO<sub>2</sub> emissions from the combustion process would be limited to those already present in the atmospheric air that enters the gas turbine (~400 ppm). Therefore, these emissions have not been considered in the LCOE calculation. Life-cycle CO<sub>2</sub> emissions for hydrogen-firing in a gas turbine are therefore mainly associated with the hydrogen production method. Hydrogen produced from renewable energy sources via electrolysis of water (“green” hydrogen) which is subsequently used in a gas turbine would enable net-zero carbon power generation. Similarly, the use of hydrogen produced from reformation of natural gas with carbon capture and storage (“blue” hydrogen) would facilitate net-zero carbon power generation, and possibly even net-negative carbon power generation if renewable gas such as biogas was used in part for hydrogen production. Offsetting of 5-10% CO<sub>2</sub> emissions not captured from blue H<sub>2</sub> production may also be necessary. The “green” and “blue” H<sub>2</sub>P routes and their associate carbon impact using gas turbines are illustrated in Figure 4.

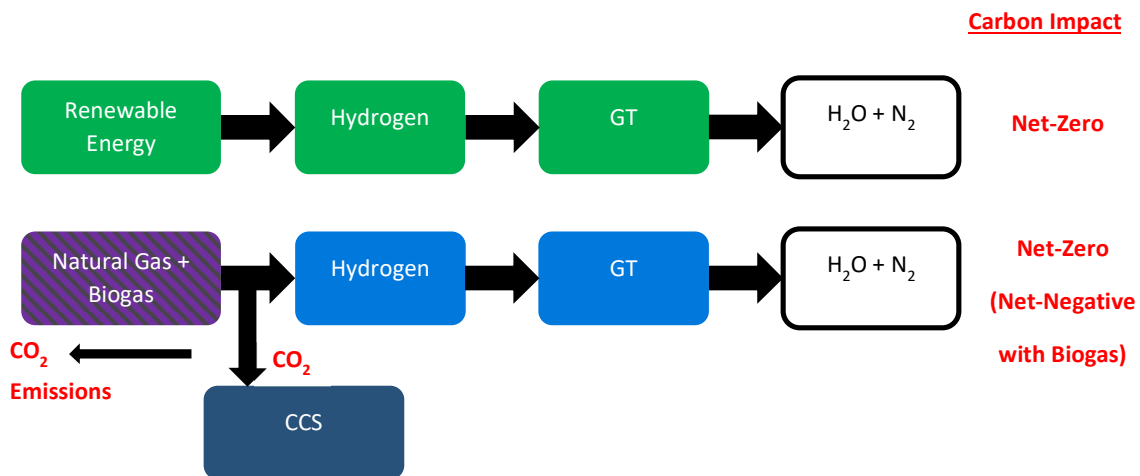


Figure 4: Net-zero hydrogen gas turbines using “green” H<sub>2</sub> (top) or “blue” H<sub>2</sub> (bottom)

Conventional diffusion, or non-premixed, gas turbine combustors using additional water, steam, or nitrogen dilution currently represent the state-of-the-art for commercial pure hydrogen fuelling in gas turbines (34). These conventional systems are generally more stable and fuel flexible than advanced lean premixed (LPM) burners. However, due to the high local flame temperatures generated in diffusion combustion systems, they are typically unable to meet strict regulatory limits on NO<sub>x</sub> (for pure H<sub>2</sub>) and CO (for H<sub>2</sub>-natural gas or syngas blends), which therefore limits their commercial viability in the future. Similar to natural gas combustion, hydrogen combustion will produce nitrogen oxides (NO<sub>x</sub>) emissions, which are a regulated environmental emission due to impacts on local air quality. However, hydrogen

combustion will eliminate carbon monoxide (CO), another highly regulated environmental emission, due to the lack of carbon in the fuel. For many years, gas turbine combustion systems have been optimised for low NO<sub>x</sub> and low CO emissions when operating on natural gas through the use of LPM burners which do not require additional dilution for emissions control. These systems are typically referred to by the GT original equipment manufacturers (OEMs) as dry low emissions (DLE) or dry low NO<sub>x</sub> (DLN). Due to this optimisation on natural gas, currently available DLE/DLN combustion systems are limited in their hydrogen capability to between approximately 30-60 %<sub>vol</sub> blends with natural gas for new build applications (34). This limit is generally driven by hydrogen's higher flame temperature than natural gas which promotes NO<sub>x</sub> formation and hydrogen's higher flame speed than natural gas which promotes flashback in LPM systems that can cause overheating and damage to combustor components. To counter these impacts on NO<sub>x</sub> formation and flashback, the gas turbine OEMs are developing solutions for both new build plant and existing plant retrofit which include new combustion system designs, new operating strategies, and new auxiliary equipment for NO<sub>x</sub> abatement, such as selective catalytic reduction (SCR). To this end in January 2019, a group of gas turbine OEMs including General Electric, Siemens, Mitsubishi Power, Ansaldo Energia, Solar Turbines, and MAN Energy Solutions signed a commitment to bring emissions-compliant, 100% hydrogen-capable gas turbines to market by 2030 (35).

In addition to the OEM focus on hydrogen combustion system development and NO<sub>x</sub> emissions control, external components will likely be impacted by hydrogen-fuelling for both open cycle gas turbines (OCGTs) and combined cycle gas turbines (CCGTs), in particular the fuel delivery system, instrumentation, and controls. Due to its low volumetric energy content compared with natural gas, hydrogen requires approximately three times the volumetric flow rate of natural gas for the same thermal input (36). Thus, an increase in the size of fuel delivery components is likely required to avoid high flow velocities and high pipeline pressure losses. The materials and sealing methods utilised in the fuel delivery system will also be impacted. In the UK, instrumentation and electrical equipment in or around hydrogen service will need to be appropriately classified for explosion protection in compliance with The Dangerous Substances and Explosive Atmospheres Regulations (DSEAR) 2002 (37), and the classification differs from that of natural gas due to hydrogen's wider flammability range, high diffusivity, and high reactivity. Among other control system changes that may be necessary, many OEMs indicate that gas turbine start-up and shut-down operations would likely require a standard fuel such as natural gas before transitioning to pure hydrogen firing (34).

For CCGTs, the operation of the heat recovery steam generator (HRSG) will also be impacted by the change in flue gas composition for hydrogen combustion compared with natural gas. This is due to the increased water content in hydrogen-derived flue gas and lack of carbon dioxide (CO<sub>2</sub>), which changes the radiative heat transfer properties in the boiler and could potentially lead to acid dew point corrosion if the heat balance is not properly managed, particularly at the downstream end of the HRSG.

The following sections will detail the current GT OEM hydrogen capabilities, ongoing hydrogen gas turbine R&D projects, hydrogen production requirements, and projected costs associated with future hydrogen gas turbine installation and operation.

## 4.3.2 Current Technology Status

### 4.3.2.1 OEM Status

Gas turbine OEMs have committed to bringing emissions-compliant hydrogen gas turbines to market by 2030 (35). It will therefore be necessary over the next decade for OEMs to close the gap between their current hydrogen capabilities and pure hydrogen capability through R&D and demonstration projects (refer to Section 4.3.2.2) While nearly all gas turbine manufacturers have commercial experience with the use of hydrogen as a fuel, whether blended or pure, the hydrogen capability of a particular GT will be a function of the machine type and combustion system employed. As this report focusses on large-scale power generation (>300 MW<sub>e</sub>), the following section considers the current

hydrogen capabilities of four gas turbine manufacturers which can deliver plants at this scale without requiring multiple units: General Electric, Siemens Energy, Mitsubishi Power, and Ansaldo Energia. Doosan Heavy Industries and Construction has not been included due to only recently entering into the large-scale gas turbine market, although it should be noted that the company has started development of a hydrogen gas turbine (38). Other industrial and small gas turbine manufacturers such as Solar Turbines, Baker Hughes, MAN Energy Solutions, Kawasaki Heavy Industries, OPRA Turbines, Capstone Green Energy, and Aurelia Turbines are also actively developing and demonstrating hydrogen gas turbine capability. These smaller GT OEMs are likely to be early market entrants for 100% hydrogen operation due to lower fuel quantity requirements and integration into high-efficiency applications such as combined heat and power (CHP).

**General Electric**

As the current gas turbine market leader (>46% market share (39)), General Electric (GE) has experience with handling a wide variety of fuels, including hydrogen for over thirty years (36). GE has more than 75 gas turbines that have operated on fuels that contain hydrogen and more than six million operating hours. A selection of GE’s hydrogen gas turbine projects is given in Figure 5.

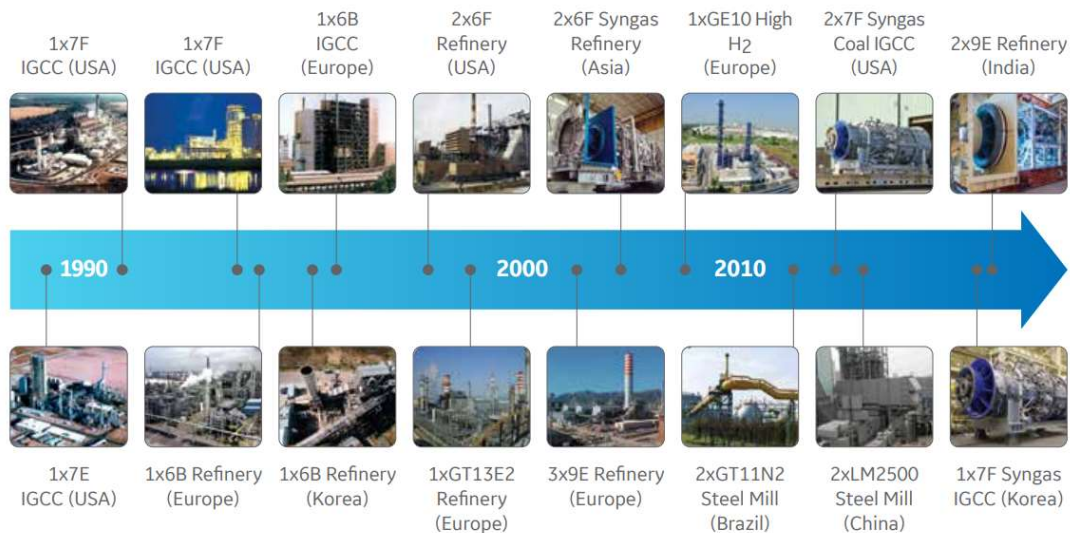


Figure 5: Timeline of selected GE hydrogen gas turbine projects (Reproduced from (36))

GE’s commercial hydrogen experience has largely relied on conventional, diffusion combustion systems due to hydrogen’s high reactivity which makes lean premixed (DLN/DLE) operation more challenging. Operating with DLN/DLE combustion systems has been limited to low levels of hydrogen blending with natural gas, for example 5%<sub>vol</sub> hydrogen in natural gas in a DLN 2.6 combustion system in four 7FA gas turbines in the United States (36). GE has conducted significant research into the use of hydrogen in gas turbines to increase these levels, most notably a ten-year (2005-2015) United States Department of Energy project to design, build, and test a new high-hydrogen combustion system (40). The DLN micromix combustor technology developed in this project for high-hydrogen operation has since been commercialised as GE’s DLN 2.6e combustion system which is capable today of 50%<sub>vol</sub> hydrogen blended with natural gas. Figure 6 below details the current (as of March 2021) and future hydrogen capability of GE’s range of gas turbines, with a particular focus on large F-Class and HA-Class gas turbines which can deliver the scale of power generation considered here.

There are a number of important caveats to this figure produced by GE, and those which are similar from other OEMs. First, this capability is expected to be for new build plant only which is further designed for the specified fuel blend given (e.g., 100% H<sub>2</sub>, H<sub>2</sub>-NG blend or High-H<sub>2</sub> syngas). Often OEMs will only allow a particular fuel specification to be used in a given combustion system (e.g.,

maximum allowable variation in C<sub>2+</sub> content in natural gas), and it is not immediately apparent how much future flexibility the OEMs will allow in a given hydrogen fuel specification. However, it is possible that future combustion systems designed for pure hydrogen will not be compatible with a wide range of, for example, H<sub>2</sub>-NG blends. Furthermore, the current hydrogen capability given in Figure 6 does not represent retrofit capability which will be dictated instead by the existing site and gas turbine limitations on a case-by-case basis.

Next, high hydrogen capability is often only available with diffusion combustion systems which are either lower efficiency due to additional dilution injection or would be non-compliant with NO<sub>x</sub> and CO emissions limits without additional exhaust gas treatment such as SCR. Finally, hydrogen capability will also depend on the combustion system employed, local emissions requirements, local natural gas quality (for H<sub>2</sub>-NG blends), and other site requirements. Thus, Table 8 has also been prepared based on publicly-available information on the hydrogen capability of individual GE combustion systems that might be found in these GE gas turbines, which shows that DLN/DLE hydrogen capability is much lower than that presented in Figure 6. This represents the gap that GE and other OEMs aim to close by 2030 (e.g., “Future Capability” in Figure 6).

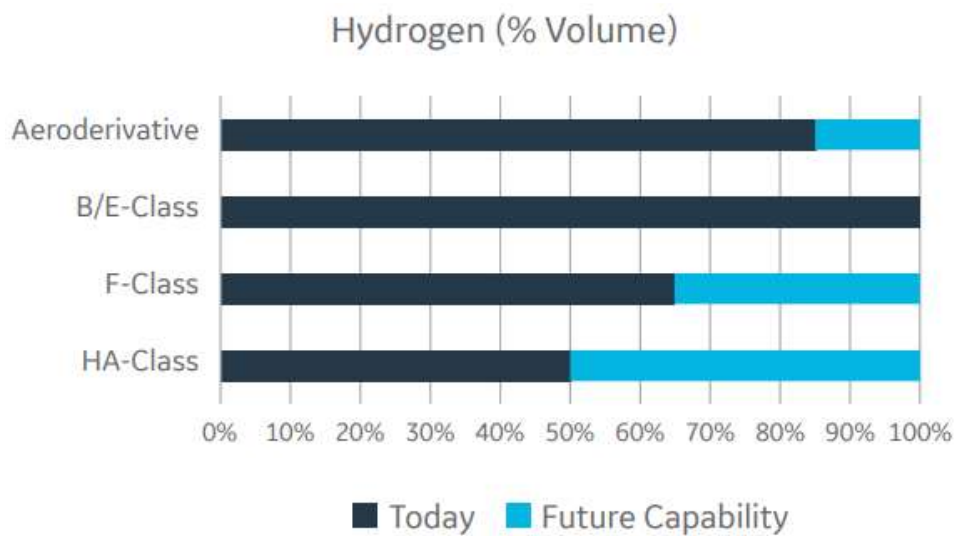


Figure 6: GE hydrogen capability (%vol) by GT class (Reproduced from (41))

Table 8: Hydrogen capability of GE DLN, DLE, and diffusion combustion systems

Class	Combustion System	DLN/DLE? (Y/N)	Maximum H <sub>2</sub> Capability (%vol)*	Reference
Aero-derivative	Single Annular Combustor	N	85%	(36)
	DLE	Y	5%	(36)
B/E	Single Nozzle	N	100%	(36)
	Multi-Nozzle Quiet Combustor	N	100%	(36)
	DLN1	Y	33%	(36)
F	Multi-Nozzle Quiet Combustor	N	90%	(42)
	DLN 2.6	Y	5%	(43)
	DLN 2.6+	Y	18%	(36)
	EV/SEV	Y	40%	(36)
HA	DLN 2.6e	Y	50%	(36)

\* Dependent on GT model, ambient conditions, natural gas composition, emissions requirements, and other site requirements

### Siemens Energy

Siemens Energy has the second largest GT market share after GE (39) and similar experience with the use of hydrogen across its GT range with more than 55 units operated on high hydrogen fuels for more than 2.5 million operating hours (44). A map of selected Siemens hydrogen gas turbine projects is given in Figure 7.

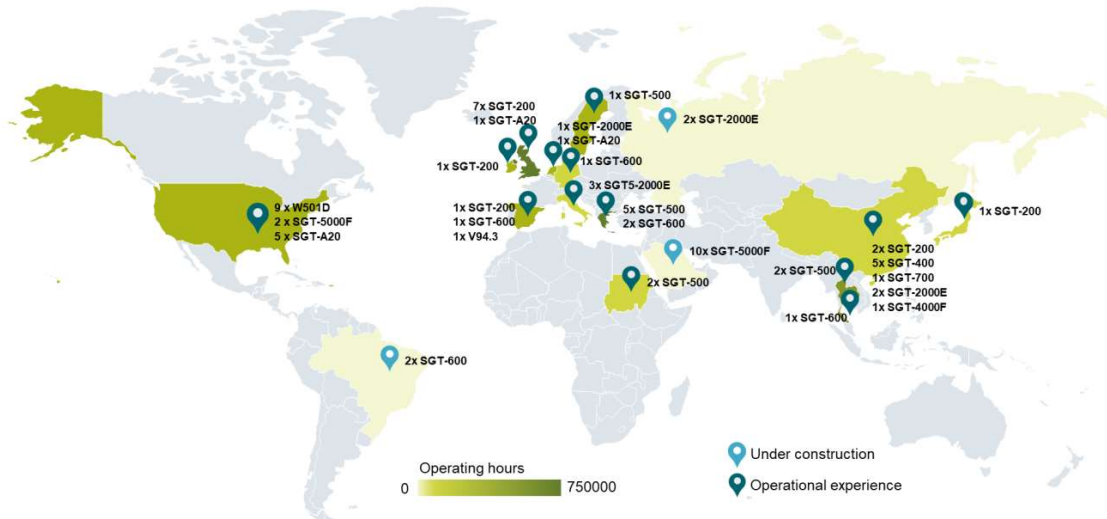


Figure 7: Map of selected Siemens Energy hydrogen gas turbine projects (Reproduced from (44)).

Similar to GE, Siemens Energy’s commercial hydrogen experience has largely relied on unabated and steam/water-diluted diffusion combustion systems, the latter termed “wet low emissions” (WLE) by Siemens. However, Siemens does appear to be more advanced in its DLE hydrogen capability than GE, particularly in the smaller-scale, industrial GTs (<100 MWe), which are capable of operating with up to 60% hydrogen today, for example, in the 24 MWe SGT-600. Siemens’ GT hydrogen capability as of March 2019 is given in Figure 8 as a function of combustion system type (DLE, WLE, and Diffusion) and GT size (simple cycle ISO power output in MWe at baseload) (45). Note a similar graphic was produced by Siemens in April 2020 with identical capabilities listed (44). It should also be noted that Siemens is currently advertising its largest H-Class gas turbine (-9000HL) has 50%vol hydrogen capability (46). Similar to GE, Siemens caveats the values given in Figure 8 as indicative for new unit applications depending on local conditions and requirements, noting that some operating restrictions and/or special hardware and modifications may be necessary.

A cross-comparison between Figure 7 and Figure 8 reveals that much of Siemens current high-hydrogen fuel experience is with its industrial GT machines (<100 MWe), although hydrogen has also been used in larger E and F class machines. Siemens has taken steps to enhance its hydrogen combustion research and development, installing a hydrogen mixing facility at its Berlin Clean Energy Centre (45) test facility as well as recent developments of the Zero Emission Hydrogen Turbine Centre in Finspång, Sweden (47).

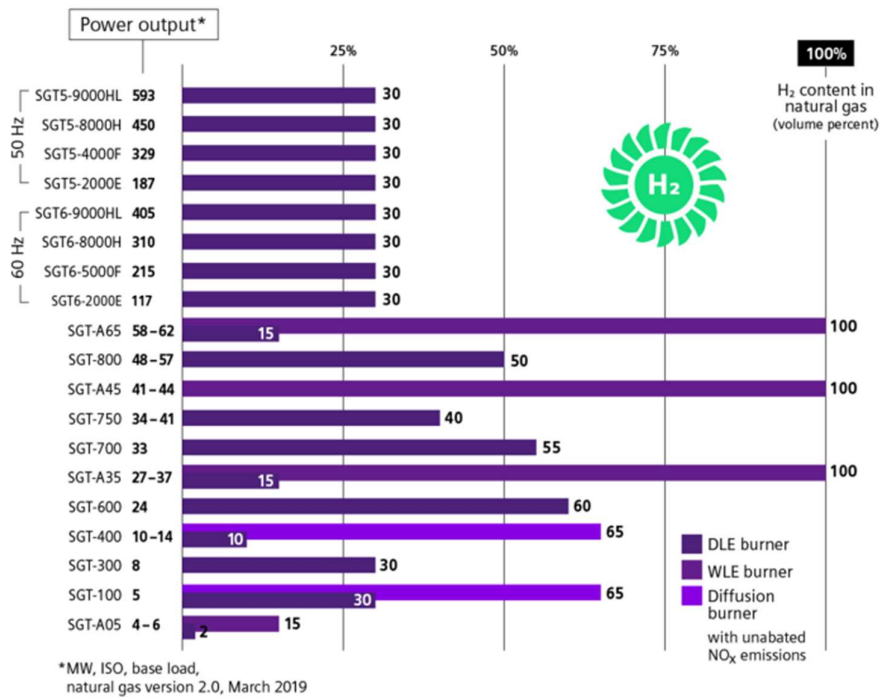


Figure 8: Siemens Energy hydrogen capability (%vol in NG) by GT power output and combustion system (Reproduced from (45))

**Mitsubishi Power**

Mitsubishi Power has the third largest GT market share (39) and has recently received support for the development of hydrogen gas turbine technology from the Japanese government’s New Energy and Industrial Technology Development Organization (48). Mitsubishi has commercial experience with the use of hydrogen syngas and refinery off-gas from 10%<sub>vol</sub> up to 90%<sub>vol</sub> with fifteen units operating for more than 2.37 million hours as of 2014 (48). A chart of selected Mitsubishi hydrogen gas turbine projects is given in Figure 9, and it should be noted that many of these high hydrogen projects utilised small gas turbines with diffusion combustion systems.

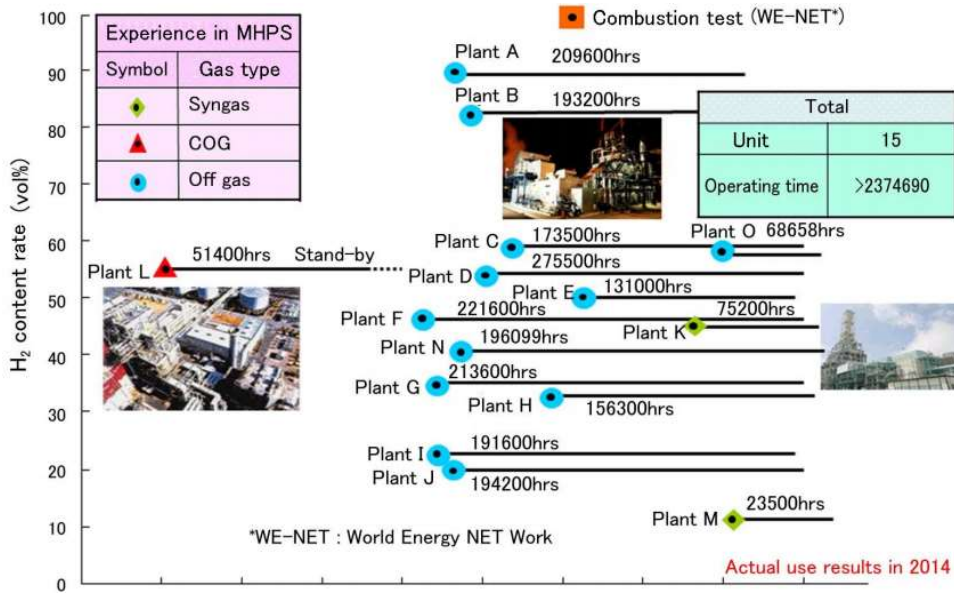


Figure 9: Timeline and H<sub>2</sub> content of selected Mitsubishi hydrogen gas turbine projects (Reproduced from (48))

Research and development into hydrogen combustion systems at Mitsubishi has produced a commercially-available premixed DLN combustion system that is capable of co-firing 30%<sub>vol</sub> hydrogen with natural gas in its large frame gas turbines. Similar to GE, Mitsubishi is also developing a combustion system based on the multiple small premixed flame concept, termed “multi-cluster combustor” by Mitsubishi (49). Figure 10 provides an indication of the current hydrogen capability of Mitsubishi’s GT range as well as the combustion systems that are under development for 100% hydrogen operation (50). This chart indicates that the multi-cluster combustor has been proven up to 30%<sub>vol</sub> hydrogen in the 41 MW<sub>e</sub> H-25 gas turbine and will likely be scaled up for the larger gas turbines.

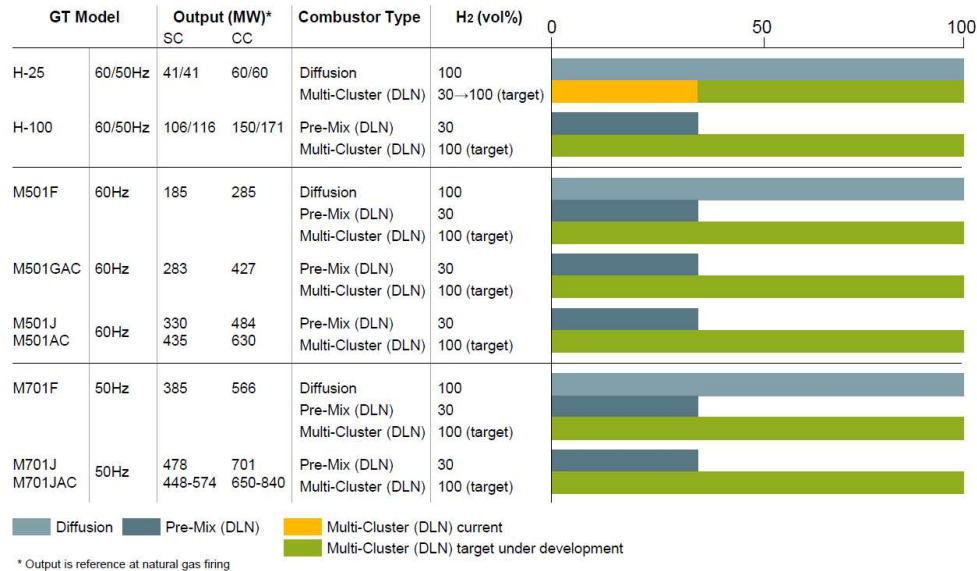


Figure 10: Mitsubishi hydrogen capability (%<sub>vol</sub>) by GT power output and combustion system (Reproduced from (50))

### Ansaldo Energia

Ansaldo Energia has the fourth largest GT market share (39) and has also been active in development of hydrogen capability for its fleet of gas turbines. In addition to its existing GTs, Ansaldo Energia acquired the mature GT26 and GT36 gas turbines from GE as part of GE’s takeover of Alstom in 2016, although GE did retain rights to some GT26 machines (thus the inclusion of EV/SEV combustion system in Table 8). One of the main differentiators of Ansaldo Energia’s GT26 and GT36 gas turbines is the use of sequential combustion systems instead single-stage combustion as is currently in use for nearly all large gas turbines from the other OEMs. There is one important difference between the two GTs: the sequential combustion of the GT36 gas turbine occurs in the same combustion can whereas there is a high pressure turbine stage between sequential combustion chambers in the GT26.

In commercial operation, two AE94.3A GTs have accumulated 215k equivalent operating hours on a 15%<sub>vol</sub> hydrogen blend with natural gas in a CCGT configuration which has subsequently increased to 25%<sub>vol</sub> hydrogen. Ansaldo also has experience operating the AE94.2K gas turbine in dilute diffusion combustion mode for over 500k equivalent operating hours on high hydrogen fuels (51).

Another key differentiator between Ansaldo and the other OEMs is that Ansaldo claims that its GT combustion systems are capable of handling any blend of H<sub>2</sub> from 0%<sub>vol</sub> up to the values listed in Figure 11. This wide range of fuel flexibility improves GT availability when operating with a variable hydrogen supply. Figure 11 provides an indication of the current hydrogen capability of Ansaldo’s large GT range as well as the different combustion systems that Ansaldo employs in its GTs.

Ansaldo Energia solutions for burning hydrogen			
Technology	Application in Gas Turbine (No hardware modification on gas turbine)	H <sub>2</sub> Capability: any blend between 0 up to max [vol %]	NOx Emissions [ppmv @15%O <sub>2</sub> , dry gases] (No additional device for flue gas treatment)
Sequential Combustion	GT36 New and service	50	15
Sequential Combustion	GT26 New and service	30	15
Single Stage Combustion	AE94.3A New and service*	25	25
Single Stage Combustion	AE94.2 New and service*	25	25

*\*including V94.3A/V94.2 technology*

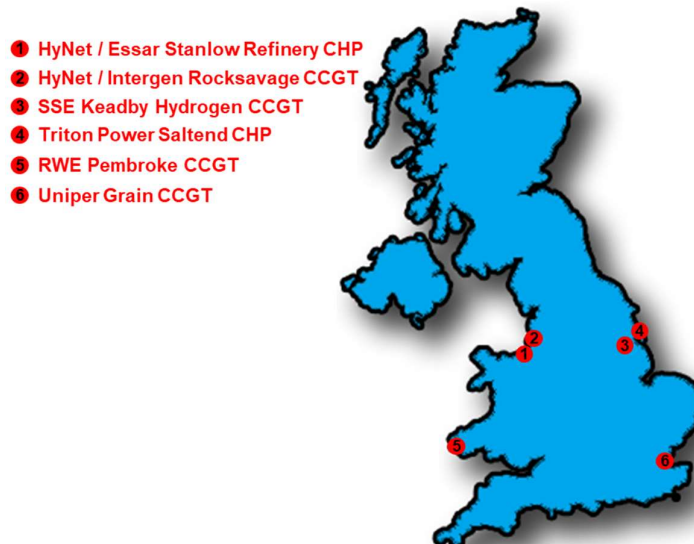
Figure 11: Ansaldo Energia hydrogen capability (%<sub>vol</sub>) by GT and combustion system (Reproduced from (51))

#### 4.3.2.2 Current Projects

In the UK and abroad, recent projects to demonstrate commercial hydrogen gas turbine technology have been announced alongside research and development work that is required to deliver on the OEMs commitment for emissions-compliant DLE/DLN combustion systems operating on pure hydrogen by 2030. These new projects complement the decades of experience and millions of operating hours that the OEMs have accumulated with high levels of hydrogen fuel, albeit often in diluted diffusion combustion systems as discussed in Section 4.3.2.1.

#### United Kingdom (UK)

As of December 2019, the UK had over 30 GW of installed CCGT generation capacity, the largest single technology in the UK’s energy mix by capacity (2). The use of hydrogen in gas turbines for power and heat generation is therefore being considered in current feasibility and FEED studies while also being considered by UK government as potential short-term dispatchable generation in 2050 net-zero scenarios (7). Figure 12 shows the locations of gas turbine power stations where recent announcements on hydrogen fuelling have been made or feasibility studies on hydrogen fuelling have been undertaken. Each project is subsequently discussed in greater detail below.



*Figure 12: UK hydrogen gas turbine projects, feasibility studies, and announcements*

In the North West, funding was awarded in 2020 to the HyNet consortium to conduct a FEED study for a new 100% hydrogen-fired gas turbine combined heat and power (CHP) plant at the Essar Stanlow Refinery (52). Prior to conducting the FEED, Progressive Energy identified that the existing 50 MW<sub>e</sub> CHP system could not be converted to hydrogen and thus a new 80 MW<sub>e</sub> hydrogen-fuelled GT CHP system would be required at an initial cost estimate of £252m with an annual hydrogen demand of 1400 GWh/yr or approximately half of the initial planned annual capacity of HyNet's low-carbon hydrogen production (3000 GWh/yr) (31), (53). The HyNet consortium has recently completed the FEED study for the Stanlow hydrogen CHP and updated cost information will be published in due course. Progressive Energy also identified a separate requirement for dispatchable hydrogen-fuelled GT generation delivering low-carbon electricity into the HyNet infrastructure which would require an additional 700 GWh/yr of hydrogen capacity. Additionally, in June 2021, HyNet and Intergen announced plans to transition the Rocksavage CCGT plant to 100% hydrogen operation, starting first with a blend of hydrogen and natural gas and then transitioning to pure hydrogen operation by 2028 as hydrogen GT technology develops (54).

In the Humber region, SSE Thermal and Equinor announced plans in April 2021 to develop the world's first 100% hydrogen-fuelled CCGT power station (Keadby Hydrogen) next to the existing Keadby 1 Power Station and under-construction Keadby 2 Power Station near Scunthorpe (55). The new Keadby Hydrogen power station would provide 900 MW<sub>e</sub> dispatchable output with a peak demand of 1800 MW of hydrogen and, according to Equinor, it could be in service before the end of the 2020s with appropriate policy mechanisms in place (55), (56). This project alone would deliver over 35% of the UK's low-carbon hydrogen production goal by 2030 (55).

Also in the Humber region, Equinor, Triton Power, and the Zero Carbon Humber partnership successfully secured funding in March 2021 for a FEED study which includes hydrogen blending up to 100% hydrogen operation at Triton's existing Saltend CCGT CHP plant as part of the Hydrogen to Humber Saltend project (57), (58). Working in partnership with its existing GT OEM, Mitsubishi Power, Triton aims to first convert its three M701F gas turbines to operate on up to 30%<sub>vol</sub> hydrogen by 2028 at the latest, before then converting the units to run on 100% hydrogen in the 2030s with a total output of 1200 MW<sub>e</sub> (57).

Recent funding of £20m was awarded to the South Wales Industrial Cluster by Innovate UK and BEIS in March 2021, part of which will enable RWE to conduct a feasibility study into the use of hydrogen for decarbonisation of the existing GT26 gas turbines at the 2200 MW<sub>e</sub> Pembroke Power CCGT plant, among other potential decarbonisation options (e.g., CCS) (59). This has led RWE to establish the Pembroke Net Zero Centre to evaluate the options available for decarbonisation (60).

National Grid, Cadent and SGN also conducted a feasibility study funded by the Network Innovation Allowance under "Project Cavendish" which considered the use of hydrogen at the Isle of Grain and further into London. The feasibility study, published in September 2020, includes consideration of hydrogen supply to Uniper's 1365 MW<sub>e</sub> Grain CCGT plant. The initial target is to supply the GT26 gas turbines with 20%<sub>vol</sub> hydrogen by 2025, increasing up to 80%<sub>vol</sub> by 2031, and 100% hydrogen by 2040, with the 100% case requiring a total annual hydrogen demand of 11.15 TWh/yr (61). In addition to the use of hydrogen in CCGTs on the Isle of Grain, the study suggests that hydrogen gas turbines could be used to replace strategic backup diesel generators for the London Underground (61).

## **International**

The International Energy Agency recently published its global roadmap for reaching net zero in the energy sector by 2050. In the "Net-Zero Emissions by 2050" scenario, 88 Mt of hydrogen would be used for electricity generation in 2050, compared with near zero today. This exceeds the total global production of hydrogen in 2020 (87 Mt H<sub>2</sub>) (62). As such, international hydrogen gas turbine projects and studies have also been announced recently in preparation for this transition away from fossil fuels. These projects are focussed mainly in North America, Europe, and Japan.

In North America, a number of commercial hydrogen gas turbine projects have been announced. Mitsubishi Power will supply two new M501JAC CCGT power trains to the Intermountain Power Plant in Utah, with operation on 30%<sub>vol</sub> hydrogen in natural gas guaranteed at commercial delivery in 2025, transitioning to operation on 100% hydrogen by 2045 (63). This project will deliver 840 MW<sub>e</sub> and is adjacent to a large underground salt cavern which will store green hydrogen for use as fuel in the gas turbines. Mitsubishi Power has further secured orders for over 4.5 GW<sub>e</sub> of hydrogen-ready gas turbines in New York, Virginia, Ohio, and Alberta, Canada all of which will be initially capable of 30%<sub>vol</sub> hydrogen operation and future operation on 100% hydrogen (64), (65). General Electric has also announced a commercial order for its GE 7HA.02 CCGT at the Long Ridge Energy Terminal in Ohio, with an initial capability of burning 15-20%<sub>vol</sub> hydrogen at commercial delivery in 2021 transitioning to 100% hydrogen by 2030 (66). This plant also has close proximity to large scale underground hydrogen storage.

In Europe, Mitsubishi Power worked with Vattenfall, Gasunie, and Statoil to conduct a feasibility study into the supply of blue hydrogen and conversion of one of three 440 MW<sub>e</sub> M701F CCGTs to operate on 100% hydrogen at the Magnum 1410 MW<sub>e</sub> power plant in Eemshaven, Netherlands (67). The project aimed to convert the M701F gas turbine to hydrogen by 2023. In France, Siemens successfully won funding from the European Union through the HYFLEXPOWER project to demonstrate 100% hydrogen operation of a 12 MW<sub>e</sub> SGT-400 gas turbine CHP system by 2023 (68). Other hydrogen gas turbine R&D projects are also underway in Europe including a partnership between Ansaldo Energia and Equinor to evaluate potential 100% hydrogen firing in Ansaldo's H-class GT36 gas turbine (69). Europe is also leading in third-party suppliers of hydrogen-ready gas turbine combustion systems with Thomassen

Energy and PSM developing the FlameSheet combustor for hydrogen engine demonstration in 2022 (70) and Crosstown Power's H2R hydrogen retrofit combustor targeting first engine testing in 2023 (71).

In Asia, significant investments have been made by the Japanese government in hydrogen technologies through the Basic Hydrogen Strategy, which aims for 15-30 GW of hydrogen-fuelled power generation by 2050 (72). To that end, an initial demonstration project was conducted in June 2020, which utilised hydrogen shipped from Brunei in an 80 MW<sub>e</sub> gas turbine at the Toa Oil Company refinery in Kawasaki (73). Additionally, Japanese gas turbine OEMs Kawasaki Power and Mitsubishi Power have demonstrated hydrogen capability in their gas turbines, with Kawasaki firing 100% hydrogen in a DLN micromix combustor in a small 1.1 MW<sub>e</sub> gas turbine (74) and Mitsubishi Power targeting validation of its DLN multi-cluster combustor operating on 100% hydrogen by 2023 (50). Finally, in April 2021, the Japanese government announced ¥26 billion (~£170m) in funding to subsidise a hydrogen gas turbine demonstration and verification project (75). In South Korea, Doosan Heavy Industries and Construction have also recently announced that the country's first large-scale hydrogen demonstration will be commissioned by 2027 at the 1.8 GW Ulsan CCGT plant. The expected output from the hydrogen GT is 270 MW<sub>e</sub> (76).

### 4.3.3 Feasibility

#### 4.3.3.1 *New Build*

As shown in Section 4.3.2.1, new build hydrogen gas turbines are technically feasible today. GT operation on 100% hydrogen has been demonstrated commercially, albeit in a limited number of applications (further applications use high-hydrogen fuel blends). Therefore, this technology is considered to be at TRL 8. However, there are a few important caveats to this current technology:

- 1) The power output of the machine is limited. Currently, Mitsubishi are the only OEM offering a 100% hydrogen capable GT today in the F-class range of ~400 MW (OCGT) / ~600 MW (CCGT) (50). All other OEM offerings are for smaller, industrial, aeroderivative, or B/E-class gas turbines which are typically lower efficiency.
- 2) Hydrogen operation requires a conventional, diffusion combustion system and likely additional steam/water or nitrogen dilution for controlling NO<sub>x</sub> emissions. This could have significant

additional costs including water (and water treatment) while also reducing maintenance intervals and overall cycle efficiency.

- 3) These GTs may require additional flue gas treatment such as SCR for NO<sub>x</sub> compliance depending on location.
- 4) These GTs would likely require a standard fuel such as natural gas for start-up before transitioning to 100% hydrogen. Thus, both natural gas and hydrogen connections to the GT would be required.

For low NO<sub>x</sub> combustion systems such as DLE/DLN, the current commercial maximum allowable hydrogen for large GTs is 50% in natural gas. The OEMs have committed to increasing commercial DLE/DLN combustion capability up to 100% hydrogen by 2030 (35). Current demonstrations of 100% hydrogen operation in DLE/DLN systems are limited to single combustor testing (e.g., Siemens SGT-800 test campaign in Berlin in 2019 (77)) and small scale GTs (e.g., Kawasaki's M1A-17, 2 MW GT with DLN micro-mix combustor operating on 100% H<sub>2</sub> in 2020 (78)). Thus, 100% hydrogen operation with DLE/DLN combustion systems has been assessed to be at TRL 5.

A key challenge for the development and demonstration of hydrogen DLE/DLN combustion systems for large GTs is the significant supply of hydrogen required. Therefore, many OEMs are offering future "hydrogen readiness" on new-build natural gas GTs such that the plant is built to handle increased hydrogen blending up to pure hydrogen during the plant's lifetime as hydrogen infrastructure and OEM combustors develop in parallel. This is evident in recent announcements about Mitsubishi's Intermountain Power Plant and GE's Long Ridge Energy Terminal projects (63), (66). In this scenario, fuel delivery piping, instrumentation and electrical equipment, and necessary civil foundations and space for possible future SCR installation are all initially designed, specified and either installed or space left for hydrogen operation. This avoids the need for wider plant retrofits when the hydrogen supply is developed and the combustion system is replaced.

There are additional technical challenges which still need to be addressed and understood such as the impact on the balance of plant, HRSG, start-up and shut-down, safety aspects (e.g., flameout, purging for maintenance), and single combustion system fuel flexibility.

For the purposes of the LCOE calculation, it is assumed that a heavy-duty F-class or H-class new-build hydrogen OCGT or CCGT is commercially available in 2030 which is NO<sub>x</sub> compliant using DLE/DLN without the need for SCR.

#### 4.3.3.2 *Retrofit*

While retrofit of existing natural gas GTs to hydrogen fuel has not been considered in the LCOE calculation, it is an area of interest for the OEMs and third-party suppliers for the decarbonisation of existing assets and/or extension of plant life (34). It is difficult to generalise the extent of retrofit that could be applied to large gas turbines, and assessments must be made on a site-by-site basis to consider the limitations of the existing site, GT, and combustion system variant currently installed. The existing systems may allow low levels of hydrogen blending (0-5%<sub>vol</sub>) with only minor changes required. For increased levels of hydrogen blending up to pure hydrogen, the requirements for retrofit are more nuanced. For brevity, only pure hydrogen retrofit is discussed below. It is worth noting that to the authors' knowledge, a complete retrofit of an existing gas turbine from natural gas to pure hydrogen has not been demonstrated commercially. However, retrofit should be technically feasible within the limitations described in the new-build section, particularly around the TRL levels of the respective combustion systems. For example, if a 100% hydrogen DLE/DLN combustion system is available in 2030, it should also be retrofittable into existing GTs assuming the design is transferable into existing machines and the plant is sufficiently upgraded to accommodate the new fuel.

In the simplest case of an existing OCGT with a conventional, diffusion combustor with steam/water or nitrogen dilution already in place, hydrogen retrofit would likely require the following:

- 1) Fuel system replacement
  - a. Increased size to accommodate higher volumetric flow

- b. Material upgrade to stainless steel to mitigate hydrogen embrittlement
  - c. New fuel supply sealing arrangements including replacing flanges with welded joints or enhanced joint fit-up and seals
  - d. Elimination of fuel dew point heaters due to hydrogen's reverse Joule-Thomson effect at pressure let-down station
  - e. New gas chromatograph and flow meters capable of handling hydrogen
- 2) Potential material and/or design upgrades to hot gas path components (e.g. turbine blades) due to different heat transfer characteristics of the combustion products
  - 3) Instrumentation and electrical equipment
    - a. Enhanced explosion protection for equipment in H<sub>2</sub> service (DSEAR/ATEX)
  - 4) Control system changes
    - a. Fuel system (e.g., GT protection based on gas composition)
    - b. Combustion dynamics (e.g., GT protections based on pulsation frequency bands)
    - c. Start-up and shut-down (particularly if standard fuel is required)

For many modern DLE/DLN combustion systems currently installed in large high-efficiency CCGTs, the requirements above would also apply generally, along with the following:

- 1) Combustion system replacement
- 2) De-rating of the machine to maintain firing temperature and NO<sub>x</sub> emissions
  - a. May enable use of existing hot gas path components
- 3) Rebalance of HRSG and steam cycle due to different heat transfer characteristics of the flue gas
- 4) Fuel efficiency preheater upgrade or resizing, if existing system was sized for natural gas and fuel temperature is to be maintained, due to hydrogen's increased heat capacity and volumetric flow rate.

#### 4.3.4 Efficiency

All efficiencies described here are on a lower heating value (LHV) basis. A 400 MW<sub>e</sub> NG CCGT would correspond approximately with an F-class size gas turbine which achieves a maximum combined cycle efficiency of 60%. For a 400 MW<sub>e</sub> NG OCGT, this would correspond approximately with an H-class gas turbine which can achieve a typical maximum simple cycle efficiency of 44%. Currently, H-class NG gas turbines in CCGT operation can achieve maximum efficiencies of around 64%. Selected gas turbines with their corresponding efficiencies and current maximum hydrogen capabilities for new builds are given in Table 9. The "1x1" specification in the CCGT configuration in Table 9 refers to a single-train CCGT (i.e., one GT exhausting into one HRSG generating steam for one steam turbine). The efficiencies highlighted in red are used in the following LCOE calculation.

For corresponding H<sub>2</sub> GT efficiencies, the following corrections are applied in the LCOE calculation:

- 1) For a First-of-a-Kind (FOAK) H<sub>2</sub> GT, the NG GT efficiency is reduced by 1%pt (79).
  - a. This is due to the reduction in firing temperature compared with the NG GT that is likely required for the H<sub>2</sub> GT to meet NO<sub>x</sub> emissions limits.
- 2) For an Nth-of-a-Kind (NOAK) H<sub>2</sub> GT, the efficiency is assumed equal to the NG GT efficiency (23).
  - a. This assumes that the GT OEMs are successful in developing new combustion systems which are capable of meeting NO<sub>x</sub> emissions limits without de-rating.

Note that while not considered here, if conventional diffusion hydrogen combustion with water/steam or nitrogen dilution was utilised, and they were required to meet the same NO<sub>x</sub> emissions limit, the expected NG GT efficiency penalty is 2% (23) or 4% (79), respectively. In addition to the efficiency penalty, increased CAPEX and OPEX would be expected, e.g., if an air separation unit was required for nitrogen production.

Table 9: Selected NG GTs with maximum efficiencies used in the LCOE calculation

Class	OEM	Model	Configuration	Output (MW <sub>e</sub> )	Efficiency (% LHV)	Current H <sub>2</sub> Capability (% <sub>vol</sub> in NG)
F	Ansaldo	AE94.3A	CCGT (1x1)	495	60%	25%
F	GE	9F.04	CCGT (1x1)	443	60.2%	15%
F	Siemens	SGT5-4000F	CCGT (1x1)	475	59.7%	30%
H	GE	9HA.01 9HA.02	OCGT CCGT (1x1)	448 838	42.9% 64.1%	50%
H	Mitsubishi	M701JAC (2018) M701JAC (2015)	OCGT CCGT (1x1)	448 840	44% >64%	30%
H	Siemens	SGT5-9000HL	CCGT(1x1)	880	>64%	50%

4.3.5 Emissions

The main benefit from the use of pure hydrogen as gas turbine fuel is the elimination of carbon dioxide (CO<sub>2</sub>) and all other carbon-based emissions including carbon monoxide (CO), unburned hydrocarbons, volatile organic compounds, and particulate matter at the point of use. The impact of hydrogen on gas turbine CO<sub>2</sub> emissions is shown in Figure 13 for a GE 9HA.02 gas turbine in CCGT configuration, which shows both impacts on carbon emissions intensity and CO<sub>2</sub> reduction with increased levels of hydrogen blending up to 100% (36). Note also in Figure 13 that the European Investment Bank (EIB) have stated that any new project that it will finance must meet the CO<sub>2</sub> Emissions Performance Standard of 250 gCO<sub>2</sub>/kWh, which would require at least 50 %vol hydrogen blending (36).

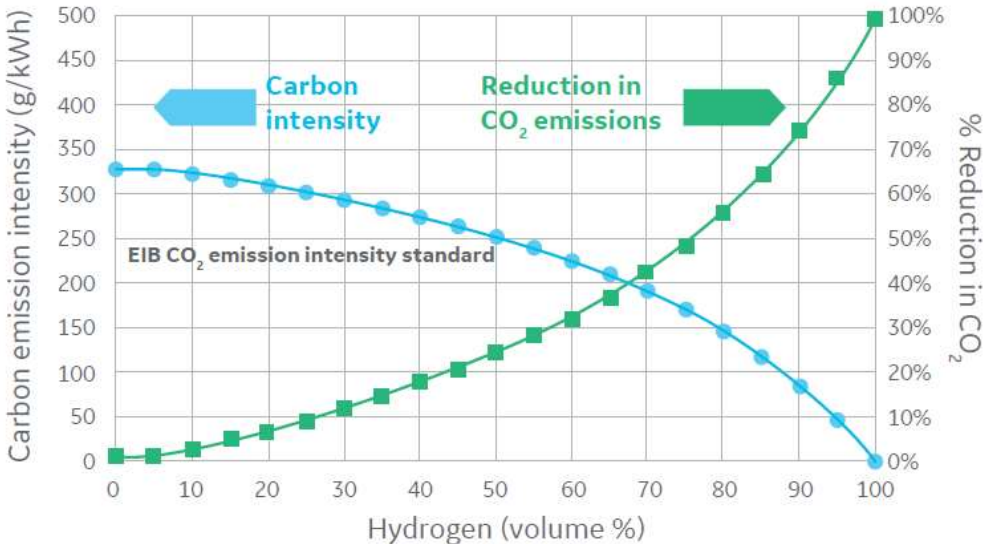


Figure 13: The impact of hydrogen blending on CO<sub>2</sub> emissions for a GE 9HA.02 CCGT (Reproduced from (36))

For the purposes of developing the carbon costs in the proceeding LCOE calculation, a baseline natural gas CO<sub>2</sub> emissions factor of 56100 kgCO<sub>2</sub>/TJ on an LHV basis is used from the 2006 Intergovernmental Panel on Climate Change Guidelines for National Greenhouse Gas Inventories (80). For a 400 MW<sub>e</sub> natural gas CCGT at the maximum F-Class efficiency given in Table 9, the resulting carbon emissions intensity is 0.335 tCO<sub>2</sub>/MWh<sub>e</sub> (335 gCO<sub>2</sub>/kWh), which is in agreement with the 0%<sub>vol</sub> hydrogen emissions intensity in Figure 13.

As mentioned in Section 4.3.1, the OEMs have indicated that it may be necessary to start-up and shut-down a hydrogen gas turbine on a standard, alternative fuel such as natural gas before transitioning to hydrogen operation (34). Therefore, there is the potential for CO<sub>2</sub>, CO, and CH<sub>4</sub> to be emitted for short periods of GT operation under no load or low load conditions. As a result, standard multi-component Continuous Emissions Monitoring System (CEMS) analysers currently in use on natural gas CCGTs may still be required for emissions monitoring and reporting. As part of hydrogen combustor developments, OEMs are investigating methods of safe GT start-up and shut-down without the need for an alternative fuel.

The main exhaust products from a hydrogen gas turbine are nitrogen (N<sub>2</sub>), oxygen (O<sub>2</sub>) and water vapour (H<sub>2</sub>O). However, as described in Section 4.3.1, the use of air as a working fluid in the gas turbine and oxidiser in the hydrogen combustion process will also produce NO<sub>x</sub> emissions (NO + NO<sub>2</sub>), which are currently highly regulated in the UK from large combustion plants such as natural gas CCGTs. NO<sub>x</sub> emissions are a particular challenge of hydrogen combustion which the gas turbine OEMs are addressing through ongoing research and development. NO<sub>x</sub> emissions are, in general, strongly correlated to flame temperature, a production pathway referred to as thermal NO<sub>x</sub>. For a fixed fuel/air ratio or firing temperature, hydrogen exhibits higher local flame temperatures than natural gas, which contributes to increased thermal NO<sub>x</sub> formation. This can be seen in Figure 14 for a range of equivalence ratios ( $\phi$ ) relative to the stoichiometric fuel/air ratio ( $\phi = 1$ ).

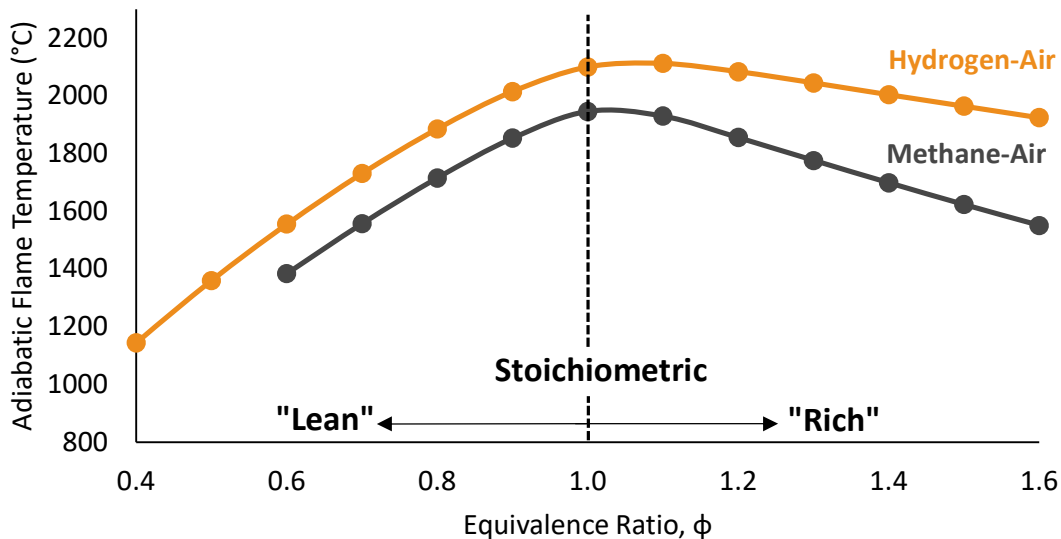


Figure 14: Flame temperature of H<sub>2</sub>-air and CH<sub>4</sub>-air mixtures at 15°C and 1 bar

Blends of natural gas and hydrogen would yield flame temperatures which sit somewhere between the two lines for the conditions given. Given the relationship between flame temperature and NO<sub>x</sub> formation, it would be expected that NO<sub>x</sub> emissions would increase from the very low levels (<10 ppmV, dry, 15% O<sub>2</sub>) of natural gas DLN/DLE systems. This can be seen in Figure 15, reproduced from (36), which shows the percentage increase in NO<sub>x</sub> emissions for a given GE gas turbine combustion system as a function of hydrogen content up to 50%<sub>vol</sub>. If the trend was continued, 100% hydrogen operation would nearly double the natural gas NO<sub>x</sub> emissions (36). Similar trends have also been identified by

Ansaldo Energia in combustor tests for the AE94.3A gas turbine, shown in Figure 16 (81). For this particular burner type, there is the possibility of changing the pilot fuel split to help offset the increase in NO<sub>x</sub> emissions, but the trends are similar to GE's. As a result, the OEMs are currently suggesting that a reduction in hydrogen GT power output by lowering the firing temperature will be required to maintain operation within current NO<sub>x</sub> emissions limits (34). This is another area of ongoing development by the OEMs with the goal of delivering a 100% hydrogen combustion system by 2030 which is NO<sub>x</sub> compliant without diluent addition or the need for post-combustion flue gas treatment via selective catalytic reduction (SCR). It is worth noting that OEMs have acknowledged that SCR may have a role to play in NO<sub>x</sub> emissions reduction from hydrogen gas turbines, depending on local emissions regulations, and that new CCGT developments may need to consider, at the least, leaving space in the exhaust ducting for SCR retrofit in the future if the gas turbine will be transitioned from natural gas to hydrogen operation. Therefore, a techno-economic analysis of NO<sub>x</sub> reduction techniques between SCR cost and hydrogen GT de-rating would likely be required. In addition, the use of SCR would likely require monitoring of NH<sub>3</sub> slip in the exhaust stream.

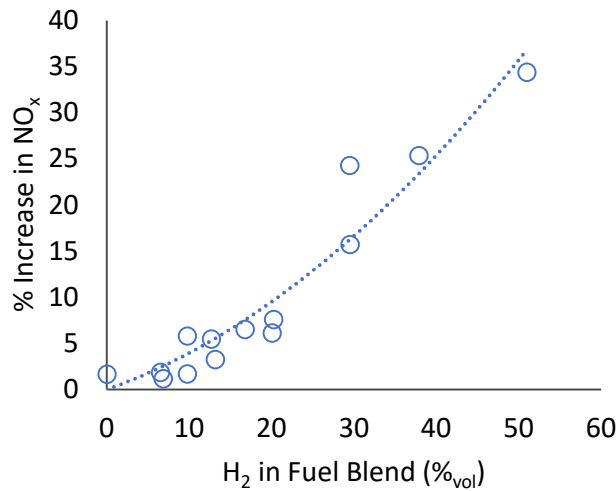


Figure 15: The impact of H<sub>2</sub> addition to NG on NO<sub>x</sub> emissions in a GE gas turbine (data reproduced from (36))

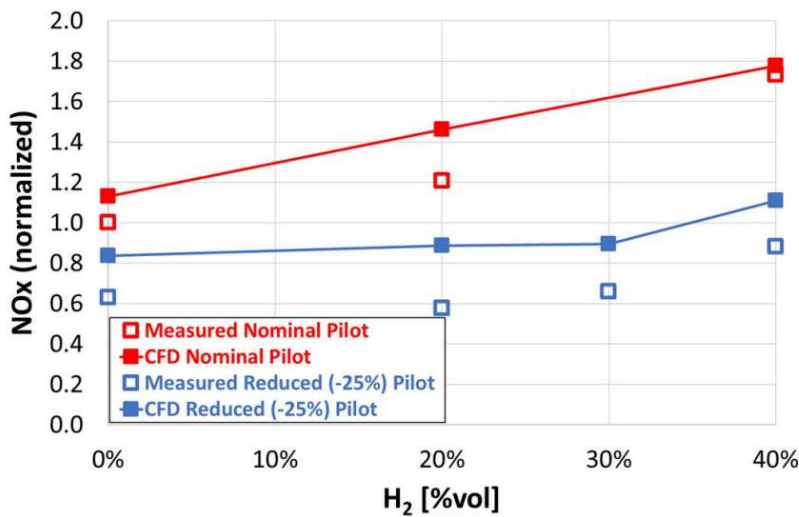


Figure 16: The impact of H<sub>2</sub> addition to NG on NO<sub>x</sub> emissions in an Ansaldo Energia AE94.3A combustor test (reproduced from (81))

It is also worth considering that hydrogen has a global warming potential (GWP) when released into the atmosphere. According to Derwent (82), hydrogen was found to have a GWP of 5.8 over a 100 year time horizon, however uncertainties in this value are large and further modelling is required. In addition to the safety case to prevent hydrogen leakage through improved sealing methods of the hydrogen GT fuel supply system, it may also be necessary to implement hydrogen fugitive emissions monitoring for environmental reporting. However, this type of monitoring is not currently regulated, and it is not currently known if regulations would require this in the future.

While the focus here has been on emissions within power generation site boundaries, the true carbon emissions associated with hydrogen firing of gas turbines will be mainly associated with the hydrogen production method. For example, the use of “grey” hydrogen (e.g., produced via unabated steam-methane reforming) in gas turbines would result in higher overall carbon emissions than Natural Gas GTs due to the high CO<sub>2</sub> emissions associated with this H<sub>2</sub> production method. Instead, this would simply shift carbon emissions from the gas turbine stack to the hydrogen production process, and the carbon cost would likely be borne out in the hydrogen delivery price to the generator.

The life-cycle CO<sub>2</sub> intensity of the hydrogen production method is strongly correlated to the greenhouse gas (GHG) emissions of the hydrogen supply (e.g., if natural gas is used in reforming resulting in fugitive methane emissions), the share of renewables supplying the grid connected to a hydrogen plant, and the raw materials required for the H<sub>2</sub> production technology, as shown in Figure 17 from the Hydrogen Council with global and local average renewables electricity shares (83). Onshore wind and hydro power feeding PEM electrolyzers to generate green hydrogen are seen to have the lowest life cycle CO<sub>2,eq</sub> emissions per kg of H<sub>2</sub> produced. As a comparison with the CO<sub>2</sub> emissions factor for natural gas combustion of 56100 kgCO<sub>2</sub>/TJ NG,LHV (80), the lowest CO<sub>2</sub> emissions associated with green hydrogen production would be 2500 kgCO<sub>2,eq</sub>/TJ H<sub>2</sub>,LHV, which is over 95% reduction notwithstanding the GHG emissions intensity associated with natural gas production.

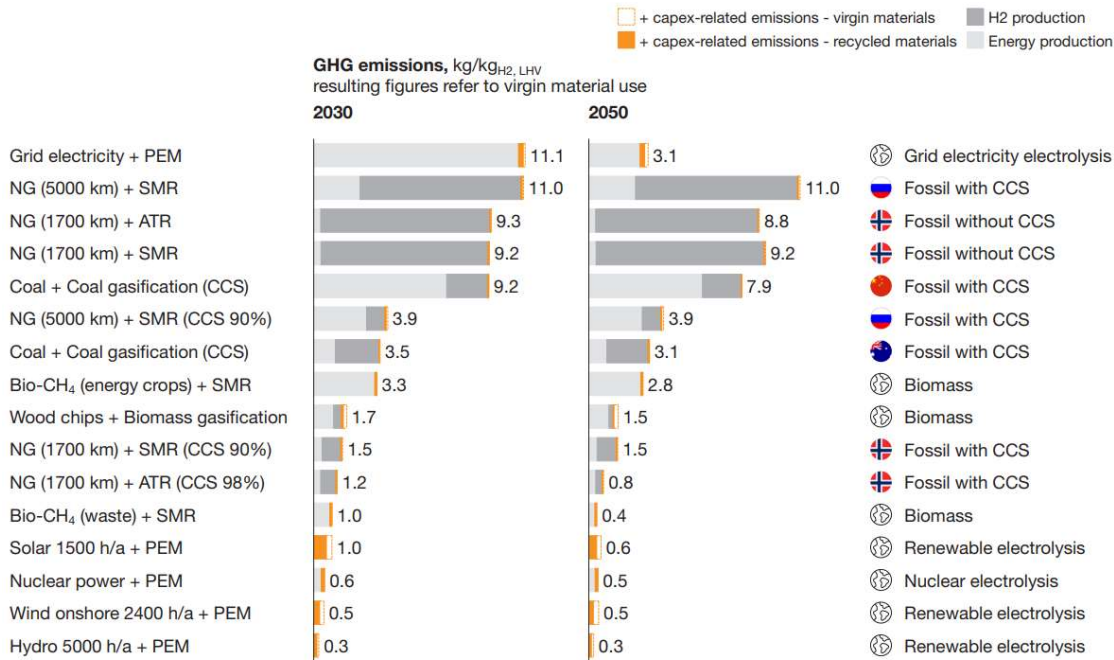


Figure 17: GHG emissions intensity (kg CO<sub>2,eq</sub> / kg H<sub>2,LHV</sub>) of various H<sub>2</sub> production methods in 2030 and 2050 (Reproduced from (83))

### 4.3.6 Flexibility and Operational Constraints

Hydrogen OCGTs and CCGTs are expected to offer similar levels of flexibility and operability as today's NG OCGTs and CCGTs, respectively, as a majority of the plant components will be similar, if not identical (particularly for retrofit applications). The main constraints which are expected to impact on operational flexibility of hydrogen GTs are NO<sub>x</sub> emissions, combustion dynamics (e.g., humming, thermoacoustics, or combustion noise), start-up and shut-down fuel requirements, and hydrogen supply. Other operational issues, such as impacts on the heat balance in the HRSG for CCGTs, are assumed to be adequately addressed in the new-build design.

As discussed in Section 4.3.5, NO<sub>x</sub> emissions may present a challenge to the operation of hydrogen GTs, depending on the success of the OEMs in developing DLE/DLN combustion systems capable of low-NO<sub>x</sub> operation by 2030. This challenge is similar to that faced by NG GTs over the past decades to operate with increasingly low NO<sub>x</sub> emissions. If necessary, mitigations to reduce NO<sub>x</sub> emissions such as GT derating and the use of SCR will impact on operations and need to be considered. Reducing firing temperatures to maintain NO<sub>x</sub> compliance will impact on maximum GT output and efficiency, resulting in higher fuel flow requirements for the same nominal output. If SCR is employed, GE has indicated that this works best in base-loaded CCGTs given the temperature dependence of the NO<sub>x</sub>-NH<sub>3</sub> catalytic reaction, and it may not be possible to use with OCGTs given the comparatively high exhaust temperature (84).

The acceptable full-load operation window of large NG GTs with DLE/DLN combustion systems is often bounded by a combination of excessive NO<sub>x</sub> and combustion dynamics or flame stability issues (blowoff or flashback). NO<sub>x</sub> emissions have been addressed previously therefore combustion dynamics and flame stability are likely the other limiting factors in hydrogen GT operational flexibility. Given hydrogen's increased flame speed, higher flame temperatures, higher diffusivity, higher air flow requirements, and behaviour under turbulent flow conditions, it is likely that the dynamic response of the GT combustor will differ from the NG combustors employed today. However, given the lack of large GT operational data on hydrogen fuel, and the likelihood that a new combustion system design will need to be employed, it is difficult to generalise the expected response. Under certain operating conditions, hydrogen may reduce combustion dynamics, while in others it may be detrimental. Hydrogen's increased flame speed may also precipitate the occurrence of flashback in premixed combustion systems under certain operating conditions. Flashback is the upstream movement of the flame into the fuel/air injection system which can overheat and damage components. Therefore, it will be crucial to identify the conditions at which this may occur and operate the GT with sufficient margin away from flashback conditions. For both combustion dynamics and flame stability, full load mapping of the combustion system and tuning of the fuel and air flows within the combustor will be required.

Given hydrogen's wide flammability range and high reactivity, it may enable lower part-load turndown on the GT than can be achieved with NG GTs. In natural gas GTs, it is typically high CO emissions in combination with lean flame stability which set the part-load turndown limit. With CO emissions eliminated in hydrogen combustion, part-load turndown will likely be limited instead by flame stability, firing temperature, or inlet guide vane (IGV) position. Adequate mapping of the combustion system at part-load conditions will also be required.

The GT industry has indicated that it may be necessary to start-up and shut-down hydrogen GTs on a standard fuel, such as natural gas (34), although it is understood that removing this requirement is part of ongoing OEM developments. This requirement is largely to mitigate the potential safety issue of unburned hydrogen accumulating and igniting in the downstream equipment (e.g., exhaust duct, HRSG, flue stack) during these events. Hydrogen GTs in operation today with diffusion combustion systems, for example in the oil and gas industry, already employ this practice. If needed, this would require a natural gas supply to the plant, sized sufficiently for the required flow rates and suitably treated to remove any contaminants. It is not immediately clear from the OEMs what impact this fuel switchover will have on start-up and shut-down durations although it is conceivable that these will increase slightly relative to typical NG GT start-up and shut-down, which is dependent on configuration (e.g., OCGT and CCGT) and start type (e.g., cold, warm, or hot). Refer to Table 10 below for indicative NG GT start-up

times from grid operator notice to grid synchronisation and grid synchronisation to full load operation (85).

*Table 10: Large NG GT indicative start-up times based on start type and technology (data reproduced from (85))*

Start Type	Technology	Notice to Sync Duration (mins)	Synch to Full Load Duration (mins)
Hot	OCGT	2-5	15-30
	CCGT	15	25
Warm	OCGT	2-5	15-30
	CCGT	15	80+
Cold	OCGT	2-5	15-30
	CCGT	15	190-240

In addition to the potential requirement to start-up and shut-down the hydrogen GT on a standard fuel such as natural gas, the OEMs are also evaluating combustor technology which is capable of full-load operation on the full range of fuel blends from 100% natural gas to 100% hydrogen. For example, Thomassen Energy have recently demonstrated the capability of its DLE FlameSheet combustor for the OPRA OP16 gas turbine to operate on both 100% natural gas and 100% hydrogen with NO<sub>x</sub> emissions <25 ppm (dry, 15% O<sub>2</sub>) (86). However, there are still a number of other factors that must be addressed in order to consider a combustion system to be fully fuel-flexible which includes start-up capability, emissions compliance, and acceptable levels of combustion dynamics across the load range. Further development work is therefore required. This level of fuel flexibility would address the potential issue of stranding a hydrogen GT asset at times of reduced hydrogen supply due to maintenance or equipment breakdown, but would also require a sufficient natural gas fuel supply and treatment system to be installed alongside the hydrogen fuel supply.. For new-build GTs, utilising fuel flexible combustion systems may reduce or eliminate the need for combustion system replacement in the future as hydrogen availability increases, providing a smoother transition from NG operation to H<sub>2</sub> operation. Additionally, for retrofit applications, NG fuel supply and treatment equipment may already be in place at a given site and thus a fuel-flexible combustion system could enable operation on the UK National Transmission System (NTS) which may have variable hydrogen blending in the future. Similar fuel redundancy options are already in place for many NG GTs today which have the dual-fuel capability to operate on fuel oil in case of NG supply issues.

In terms of maintenance of hydrogen GTs, it is expected that existing NG GT maintenance intervals would apply if DLE/DLN is employed and firing temperatures are unchanged. Reduced maintenance intervals may be required by the OEM for qualification of FOAK hydrogen GTs and if steam/water injection is used for NO<sub>x</sub> control (34).

#### 4.3.7 Requirements

##### 4.3.7.1 Hydrogen Production

Operation of power generation gas turbines on 100% hydrogen fuel requires less flow than natural gas on a mass basis but approximately three times the volumetric flow for the same heat input due to hydrogen's low volumetric heating value (36), as shown in Table 11. This increase in volumetric fuel

flow affects the fuel delivery system and fuel injection design, as well as hydrogen transport and storage systems connected to power generation sites.

*Table 11: Fuel properties of natural gas and hydrogen*

Fuel	Density (kg/m <sup>3</sup> )*	LHV (MJ/kg)	HHV (MJ/kg)	LHV (MJ/m <sup>3</sup> )	HHV (MJ/m <sup>3</sup> )
Natural Gas (87)	0.76**	48.3 (87)	53.5 (87)	36.9	40.9
Hydrogen (H <sub>2</sub> )	0.09 (88)	120.1 (89)	141.9 (89)	10.8	12.8

\*At 0°C, 1 atm

\*\*Calculated using AGA8 from composition given in (87)

Based on the FOAK and NOAK H<sub>2</sub> GT efficiencies defined in Section 4.3.4, Table 12 has been developed to detail the required hydrogen fuel flow for 100% H<sub>2</sub> operation of the reference GTs. These hydrogen flows are then used to calculate the fuel costs which form a significant portion of the overall LCOE calculation for each of the cases considered as shown in Section 4.4.

The cases in Table 12 are arranged in order of increasing GT cycle efficiency to highlight the resulting impact on the fuel flow requirements, with the FOAK H<sub>2</sub> OCGT requiring 0.07 tH<sub>2</sub> per MWh generated and the NOAK H<sub>2</sub> CCGT (H-class) requiring 0.047 tH<sub>2</sub> per MWh generated. For comparisons with HyNet's H<sub>2</sub> production plant capacity, a 400 MW<sub>e</sub> NOAK H<sub>2</sub> CCGT would require 222 kNm<sup>3</sup>/hr of hydrogen. This is over twice the H<sub>2</sub> production capacity of the initial HyNet Low Carbon Hydrogen (LCH) plant (100 kNm<sup>3</sup>/hr) (31), requiring at least the 3x100 kNm<sup>3</sup>/hr LCH plant buildout to enable 100% H<sub>2</sub> operation. An NOAK 880 MW<sub>e</sub> H<sub>2</sub> CCGT would require 458 kNm<sup>3</sup>/hr, which would require the further-increased HyNet LCH plant buildout (1x100 kNm<sup>3</sup>/hr plus 1x500 kNm<sup>3</sup>/hr) to enable 100% H<sub>2</sub> operation.

*Table 12: Hydrogen fuel flow requirements for FOAK and NOAK H<sub>2</sub> OCGT and CCGT*

Configuration	Output (MW <sub>e</sub> )	Efficiency (% LHV)	Thermal Input (MW <sub>th</sub> , LHV)	H <sub>2</sub> Flow (tH <sub>2</sub> /hr)	H <sub>2</sub> Flow (kNm <sup>3</sup> /hr)	H <sub>2</sub> per MWh <sub>e</sub> (tH <sub>2</sub> /MWh <sub>e</sub> )
FOAK OCGT (H-class)	400	43.0%	930	27.9	310	0.070
NOAK OCGT (H-Class)	400	44.0%	909	27.3	303	0.068
FOAK CCGT (F-class) (1x1)	400	59.2%	676	20.3	225	0.051
NOAK CCGT (F-class) (1x1)	400	60.2%	664	19.9	222	0.050
NOAK CCGT (H-class) (1x1)	880	64.1%	1373	41.2	458	0.047

#### 4.3.7.2 Hydrogen Purity

GT combustion systems are, in general, relatively flexible in regards to fuel composition, with OEMs often specifying allowable ranges of natural gas composition including Wobbe Index, C<sub>2+</sub> content, and inert (N<sub>2</sub>, CO<sub>2</sub>, and Ar) content (90). For hydrogen combustion, lower hydrogen purity relative to, for example, fuel cells used for vehicle transport (minimum 99.97% volume hydrogen per BS ISO 14687 (91)) could likely be tolerated. This is particularly true for conventional, diffusion combustion systems, whereas DLE/DLN premixed combustions system generally would have stricter fuel specifications. According to the European Turbine Network, this enables hydrogen GTs to stimulate commercial demand for large amounts of low purity hydrogen, which would have the effect of lowering hydrogen production costs (34). Hydrogen could then be purified further for other applications as required.

For new build GTs, the fuel quality is often specified as part of the purchasing process. This presents a potential opportunity to co-locate hydrogen power generation from GTs with low-carbon hydrogen production such that the GT utilises a low purity hydrogen stream prior to further purification and injection into the local gas network (34). The purity of the hydrogen used in the GT would then depend on the hydrogen production process employed. If the new build GT was instead supplied at a location served by the local H<sub>2</sub> network, the purity would likely be higher, for example, 99.999% based on the hydrogen purity of HyNet's LCH output specification (31).

Regardless of the hydrogen purity used, it is likely that the gas turbine OEMs will require fuel contaminants to be within specified levels similar to those of natural gas as these contaminants may cause material degradation issues within the hot gas path. This may include limits placed on trace metals (lead, vanadium, calcium, magnesium, sodium, potassium), particulates, and liquids (90). As OEMs develop DLE/DLN hydrogen combustion systems further, this will need to be clarified as it is not currently known the amount of variation in hydrogen composition that can be tolerated or if, for example, the increased moisture content of hydrogen flue gas relative to natural gas impacts on the allowable levels of fuel contaminants.

#### 4.3.7.3 Connection Requirements

In general, it is expected that the boundary limit utility connections required for hydrogen OCGTs and CCGTs will be similar to those fuelled by natural gas. These consist of fuel supply, electrical import, electrical export, water supply, and water discharge. If the new-build hydrogen GT also requires an SCR for NO<sub>x</sub> emissions reduction, then an ammonia supply will also be required. The list below assumes no additional water injection into the combustion system for NO<sub>x</sub> control and no requirement from the OEM for a standard start-up and shut-down fuel.

For a 400 MW<sub>e</sub> OCGT, the following would likely be required:

- 1) Hydrogen supply pipeline branch connected to main hydrogen supply pipeline, operating at typical UK NTS pressure
  - a. For the OCGT case, more hydrogen flow will need to be accommodated in this supply pipeline than the 400 MW<sub>e</sub> CCGT case (see Table 12).
  - b. In comparison with a natural gas supply pipeline, new hydrogen supply pipeline is expected to be larger in diameter for the same operating pressure.
  - c. Given the volume of hydrogen required to operate a gas turbine of this size, it is also likely that the main hydrogen supply will be connected to a large hydrogen storage system such as an underground salt cavern.
- 2) Electrical grid connection for import of electricity supply to site
- 3) Electrical grid connection for export of electricity produced on site
- 4) Water supply to auxiliary and fire system
- 5) Water discharge from auxiliary and fire system
- 6) SCR NO<sub>x</sub> control system (optional, based on DLE/DLN capability)
- 7) Natural gas supply pipeline (optional, for back-up fuel supply)

For a 400 MW<sub>e</sub> CCGT, the same boundary limit utility connections as for the OCGT would likely be required with the addition of the steam system requiring an increased water supply and discharge. It is expected that the water abstraction and consumption of a hydrogen CCGT would be similar to that of an existing NG CCGT and approximately half of a NG CCGT with CCS (92). It may also be possible to reduce the size of the fuel delivery pipeline branch for a hydrogen CCGT configuration due to the lower fuel flow requirement.

Typical major equipment item lists for a natural gas CCGT can be found in Case 13 from the National Energy Technology Laboratory's report "Cost and Performance for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity", which considers a 565 MW<sub>e</sub> CCGT based on a 2x1 GE 7FB gas turbine arrangement (93).

### 4.3.8 Forecast Costs

#### 4.3.8.1 CAPEX

In addition to the capital expenditure (CAPEX) contribution from the utility connections described in Section 4.3.7.3 major on-site equipment including the gas turbine (OCGT and CCGT), generator (OCGT and CCGT), steam turbine (CCGT only), and HRSG (CCGT only) are also significant contributions to the CAPEX of a new build hydrogen GT. A more complete list of typical capital equipment and indicative prices can be found in (93). Note that ~30% inflation should be applied to the 2007 USD (\$) equipment prices in (93) to equate with 2021 costs.

As discussed previously, a hydrogen GT is likely to have many of the same components as a natural gas GT, whether OCGT or CCGT, with the main exceptions of the upgraded combustion system, fuel handling and delivery system, and selected pieces of instrumentation and electrical equipment in hydrogen service. In fact, multiple sources have been identified which predict that NOAK hydrogen GTs will have the same or similar CAPEX as natural gas GTs (23), (94), (95), (96). For FOAK hydrogen GTs, there is expected to be a CAPEX increase of approximately 3.5% from the NG OCGT and CCGT equivalent (95).

CAPEX for OCGTs and CCGTs is often expressed in terms of cost per kW<sub>e</sub> of output capacity (£/kW<sub>e</sub>). Table 13 provides the CAPEX values for 400 MW<sub>e</sub> NG OCGTs and CCGTs which are derived from a range of public sources. The H<sub>2</sub> GT CAPEX values are then calculated based on these values.

Table 13: CAPEX for 400 MW<sub>e</sub> NG and H<sub>2</sub> GT Configurations

Type	Technology	NG CAPEX (£/kW <sub>e</sub> )	H <sub>2</sub> CAPEX (£/kW <sub>e</sub> )
FOAK	OCGT	---	455
NOAK	OCGT	440	440
FOAK	CCGT	---	807
NOAK	CCGT	780	780

For the NG OCGT CAPEX of £440/kW<sub>e</sub> in Table 13, this is derived from an average of CAPEX costs given by:

- 1) Cloete et al. = £447/kW<sub>e</sub> (94)
  - a. A currency exchange rate of £1.00 = €1.14 was used from the IEA (62).
- 2) LeighFisher Ltd = £433/kW<sub>e</sub> (97)
  - a. CAPEX includes pre-development costs, construction costs, infrastructure costs, and 10% inflation from the reported 2014 costs to 2021 costs.
  - b. Note the LeighFisher Ltd CAPEX is for a 400 MW<sub>e</sub> OCGT operating 2000 hours/yr.
- 3) NG OCGTs are assumed to be NOAK.

For the NG CCGT CAPEX of £780/kW<sub>e</sub> in Table 13, this is taken directly from the IEA as follows:

- 1) IEA = £780/kW<sub>e</sub> (62)
  - a. A currency exchange rate of \$1.00 = £0.78 was used from the IEA (62).
  - b. CAPEX costs are given as constant in 2020, 2030, and 2050 in both Europe and the United States
- 2) This value is similar to others found in the public domain:
  - a. Halsback et al. = £782/kW<sub>e</sub> (93)
    - i. 30% inflation was applied to 2007 USD (\$) CAPEX
    - ii. A currency exchange rate of \$1.00 = £0.78 was used from the IEA (62).
  - b. Cloete et al. = £797/kW<sub>e</sub> (94)
    - i. A currency exchange rate of £1.00 = €1.14 was used from the IEA (62).
  - c. Aurecon Australasia Pty Ltd = £820/kW<sub>e</sub> (98)
    - i. A currency exchange rate of £1.00 = AUD (\$) 1.83 was used from HM Revenue & Customs (99).
    - ii. Note the Aurecon CAPEX is for a 400 MW<sub>e</sub>, F-class CCGT
  - d. U.S. Energy Information Administration (EIA) = £823/kW<sub>e</sub> (100)
    - i. A currency exchange rate of \$1.00 = £0.78 was used from the IEA (62).
    - ii. Note the US EIA costs are for a 430 MW<sub>e</sub> H-class CCGT and include both post-combustion NO<sub>x</sub> and CO reduction systems
  - e. Note that not all sources provide a complete breakdown of the CAPEX contributions which can lead to some variation, such as whether or not contingency or owner's costs (e.g., studies, permitting, land, interconnections) are included. Additionally, regional variations in costs can also impact on CAPEX (62).

#### 4.3.8.2 OPEX

Operational expenditure (OPEX) is generally divided into two distinct costs, Fixed Operating and Maintenance (Fixed O&M) costs and Variable Operating and Maintenance (Variable O&M) costs. Fixed O&M for GTs typically includes a fixed payment portion of the long-term service agreement, staff and admin costs, supplies, and minor routine maintenance (100). Fixed O&M is generally expressed as an annual cost per MW<sub>e</sub> of output capacity (£/MW<sub>e</sub>) applied across the expected life of the GT. Variable O&M for GTs typically includes an average annual cost of planned maintenance events over the expected life of the gas turbine and consumables such as water, lubricants, and chemicals/catalysts. Variable O&M is generally expressed as a cost per MWh generated annually (£/MWh), which accounts for the GT operating regime.

Similar to the impact on CAPEX, the use of hydrogen is expected to have little impact on the Fixed and Variable O&M for NOAK GTs, particularly if the GT operates at the same firing temperature or needs to be de-rated relative to a NG GT. For FOAK hydrogen GTs, the same 3.5% increase in CAPEX has been applied to the Fixed and Variable O&M values for NG GTs (95). This accounts for likely reduced inspection intervals and increased parts replacement that may result from the OEMs introduction of a new combustion product into the market. NG OCGTs and CCGTs are assumed to be NOAK.

Table 14 and Table 15 provide the Fixed and Variable O&M values, respectively, for 400 MW<sub>e</sub> NG OCGTs and CCGTs which are derived from a range of public sources. The H<sub>2</sub> GT OPEX values are then calculated based on these values.

Table 14: Annual Fixed O&M for 400 MW<sub>e</sub> NG and H<sub>2</sub> GT Configurations

Type	Technology	NG Fixed O&M (£/MW <sub>e</sub> )	H <sub>2</sub> Fixed O&M (£/MW <sub>e</sub> )
FOAK	OCGT	---	10160
NOAK	OCGT	9882	9882
FOAK	CCGT	---	13186
NOAK	CCGT	12825	12825

Table 15: Annual Variable O&M for 400 MW<sub>e</sub> NG and H<sub>2</sub> GT Configurations

Type	Technology	NG Variable O&M (£/MWh)	H <sub>2</sub> Variable O&M (£/MWh)
FOAK	OCGT	---	1.48
NOAK	OCGT	1.43	1.43
FOAK	CCGT	---	1.85
NOAK	CCGT	1.78	1.78

For the annual NG OCGT Fixed O&M of £9882/MW<sub>e</sub> in Table 14, this is derived from an average of Fixed O&M costs given by:

- 1) Cloete et al. = £11162/MW<sub>e</sub> (94)
  - a. A currency exchange rate of £1.00 = €1.14 was used from the IEA (62).
- 2) LeighFisher Ltd = £8602/MW<sub>e</sub> (97)
  - a. Fixed O&M includes 10% inflation from the reported 2014 costs to 2021 costs.
  - b. Note the LeighFisher Ltd Fixed O&M is for a 400 MW<sub>e</sub> OCGT operating 2000 hours/yr.

For the annual NG CCGT Fixed O&M of £12825/MW<sub>e</sub> in Table 14, this is derived from an average of Fixed O&M costs given by:

- 1) Cloete et al. = £19934/MW<sub>e</sub> (94)
  - a. A currency exchange rate of £1.00 = €1.14 was used from the IEA (62).
- 2) LeighFisher Ltd = £12584/MW<sub>e</sub> (97)
  - a. Fixed O&M includes 10% inflation from the reported 2014 costs to 2021 costs.
  - b. Note the LeighFisher Ltd Fixed O&M is for a 1400 MW<sub>e</sub> F-Class CCGT arrangement
- 3) Aurecon Australasia Pty Ltd = £5956/MW<sub>e</sub> (98)
  - a. A currency exchange rate of £1.00 = \$A 1.83 was used from HM Revenue & Customs (99).
  - b. Note the Aurecon Fixed O&M is for a 400 MW<sub>e</sub>, F-class CCGT

For the annual NG OCGT Variable O&M of £1.43/MWh in Table 15, this is derived from an average of Variable O&M costs given by:

- 1) Cloete et al. = £1.75/MWh (94)
  - a. A currency exchange rate of £1.00 = €1.14 was used from the IEA (62).
- 2) LeighFisher Ltd = £1.11/MWh (97)
  - a. Variable O&M includes 10% inflation from the reported 2014 costs to 2021 costs.
  - b. Note the LeighFisher Ltd Variable O&M is for a 400 MW<sub>e</sub> OCGT operating 2000 hours/yr.

For the annual NG CCGT Variable O&M of £1.78/MWh in Table 15, this is derived from an average of Variable O&M costs given by:

- 1) Cloete et al. = £1.75/MWh (94)
  - a. A currency exchange rate of £1.00 = €1.14 was used from the IEA (62).
- 2) LeighFisher Ltd = £1.57/MWh (97)
  - a. Variable O&M includes 10% inflation from the reported 2014 costs to 2021 costs.
  - b. Note the LeighFisher Ltd Variable O&M is for a 1400 MW<sub>e</sub> F-Class CCGT arrangement
- 3) Aurecon Australasia Pty Ltd = £2.02/MWh (98)
  - a. A currency exchange rate of £1.00 = \$A 1.83 was used from HM Revenue & Customs (99).
  - b. Note the Aurecon Variable O&M is for a 400 MW<sub>e</sub>, F-class CCGT

## 4.4 Levelised Cost of Electricity

### 4.4.1 Methodology

In order to compare the cost of the technologies discussed above, the Levelised Cost of Electricity (LCOE) will be used. LCOE is defined as the discounted lifetime cost per unit of generation (101). This is calculated as the ratio of Net Present Value (NPV) of total costs to NPV of electricity generation. Here, we will express LCOE in units of £/MWh.

Estimates of First Of A Kind (FOAK) and Nth Of A Kind (NOAK) CAPEX and OPEX for a typical 400 MW plant are given in Section 4.2.8 and Section 4.3.8 for post-combustion capture and hydrogen turbines respectively. As it is not possible at this stage to comment on the relative perceived risk of technologies and how this may change over time, contingency and insurance have been excluded from the cost estimations.

The following assumptions have been made across all LCOE calculations:

- Plant life of 25 years (101)
- Debt period (T) equal to plant life (101)
- Discount rate (r) of 10% (102)
- High load factor of 85%
- Low load factor of 15%

Load factors have been chosen to be reflective of values for 'peaking' and base load plant, however, further analysis of predicted plant load factors for both Hydrogen Turbines and Gas CCS is shown in Section 6.2.

Natural gas, hydrogen and CO<sub>2</sub> prices are assumed to remain constant throughout plant life. The specific values vary across the cases considered and are discussed below.

For FOAK and NOAK base cases, both high (85%) and low (15%) load factors were considered to represent a base load and a peaking plant respectively. However, load factors are dynamic and future predictions vary significantly. As such, the impact of load factors on LCOE is discussed in more detail in Section 4.4.5.

From the above assumptions, the Fixed Charge Rate (FCR) can be calculated to be equal to 0.109 using the below formula:

$$FCR = \frac{r}{(r + 1)^T - 1} + r$$

The FCR can be used to calculate the CAPEX contribution to LCOE:

$$CAPEX \text{ LCOE Contribution} = \frac{CAPEX \times FCR}{Annual \text{ Electricity Production}}$$

OPEX contributions were found by similar placing onto a per MWh basis:

$$OPEX \text{ LCOE Contribution} = \frac{Average \text{ Annual OPEX}}{Annual \text{ Electricity Production}}$$

### 4.4.2 Base Case

A number of sensitivities were run to determine the effect of load factor, carbon price and hydrogen price in Sections 4.4.5 to 4.4.7. However, a base case has been defined for both FOAK (2030) and NOAK (2035) as described in Sections 4.2.8 and 4.3.8.

A summary of the LCOE for each technology in these base cases is shown in Figure 18.

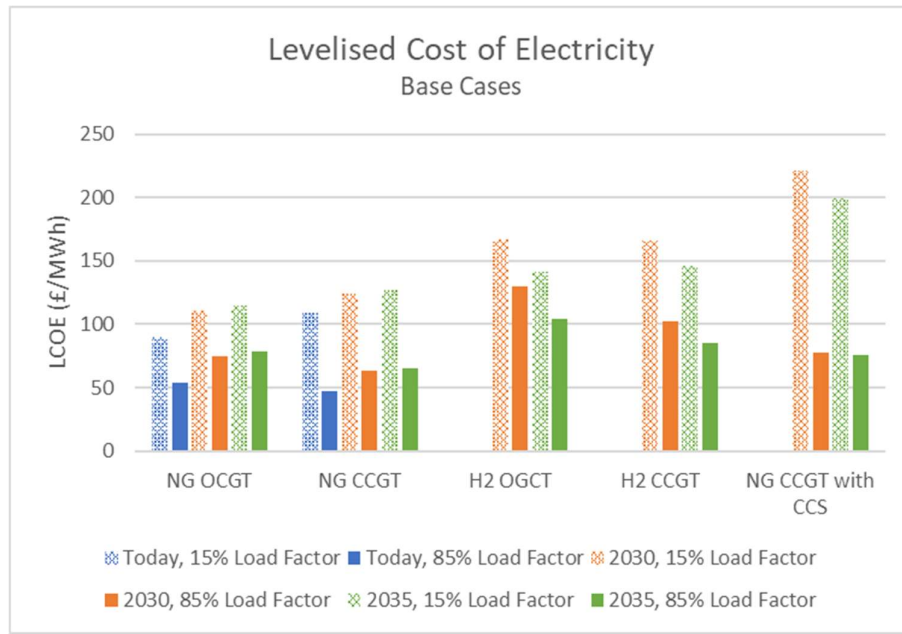


Figure 18: LCOE Base Cases Summary

4.4.2.1 Today Base Case

The reference case to compare to today’s operation is unabated Natural Gas (NG).

The following assumptions have been made for today’s base case with further explanation below:

- Year of commissioning - 2021
- Natural gas price - £16.72/MWh
- Carbon price - £14.56/tCO<sub>2</sub>

For the future scenarios discussed, BEIS predictions are used for natural gas and carbon prices. To maintain consistency, the 2021 predictions from these sources (made in 2019) are used for today’s prices (103).

For 2021, BEIS predicted natural gas prices to be between 33 and 74p/therm with a central prediction of 49p/therm (103) – equivalent to £16.72/MWh.

BEIS predicted the carbon price to be between £0/tCO<sub>2</sub> and £29.11/tCO<sub>2</sub> in 2021 with a central prediction of £14.56/tCO<sub>2</sub> (104). This central value is taken for the base case. However, it should be noted that this is lower than the current value within the UK Emissions Trading Scheme (UK ETS) which ended at £45.75 on the first day of auctions (105). This higher price will be covered by the sensitivities in Section 4.4.6.

As shown in Figure 19, for a NG CCGT, this gives an LCOE of £109.04/MWh for 15% load factor and £47.61/MWh for 85% load factor. A NG OCGT is cheaper at the lower load factor but more expensive at the higher load factor with LCOE of £89.85/MWh and £53.56/MWh respectively.

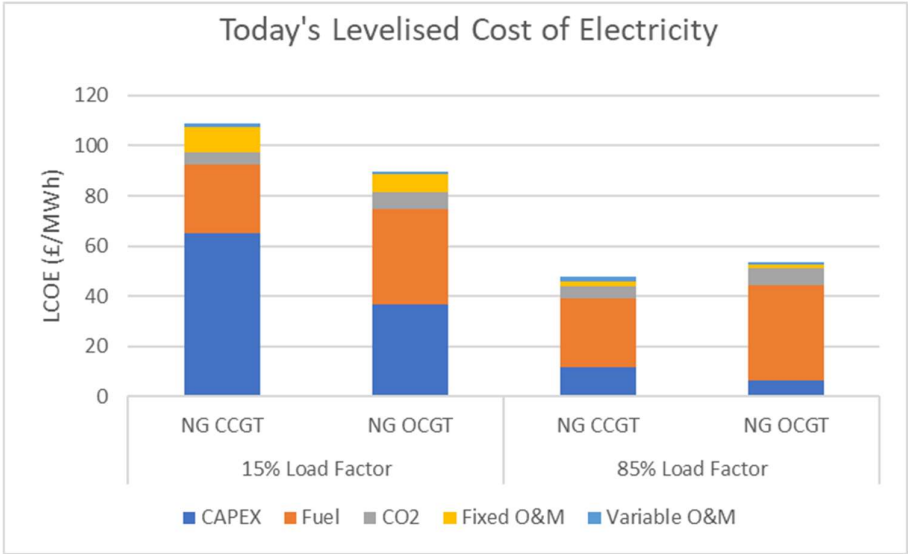


Figure 19: Today Base Case LCOE

4.4.2.2 FOAK Base Case

The following assumptions have been made for the FOAK base case with further explanation below:

- Year of commissioning - 2030
- Natural gas price - £20.31/MWh
- Hydrogen price - £43.64 MWh (HHV)
- Carbon price - £42.66/tCO<sub>2</sub>

In 2030, BEIS predicts natural gas prices to be between 40 and 83 p/therm with a central prediction of 59p/therm (103) – equivalent to £20.13/MWh.

Hydrogen is assumed to be supplied from the local HyNet deployment project. The HyNet low carbon hydrogen plant is expected to be operational by mid-2024 and to be able to deliver a levelised cost of hydrogen of £43.46 MWh (HHV basis) from this initial phase (31). On an LHV basis, this is calculated to be £51.36 MWh from hydrogen heating values (106).

BEIS predicts the carbon price to be between £18.67/tCO<sub>2</sub> and £84.61/tCO<sub>2</sub> in 2030 with a central prediction of £42.66/tCO<sub>2</sub> (104). This central value is taken for the FOAK base case. As mentioned above, this is lower than the current value within the UK Emissions Trading Scheme (UK ETS) which ended at £45.75 on the first day of auctions (105). This higher price will be covered by the sensitivities in Section 4.4.6.

The LCOE for each technology (including natural gas reference cases) is shown in Figure 20 and Figure 21 for 15% and 85% load factor respectively. Please note that OGCTs are unlikely to be the technology of choice at higher load factors.

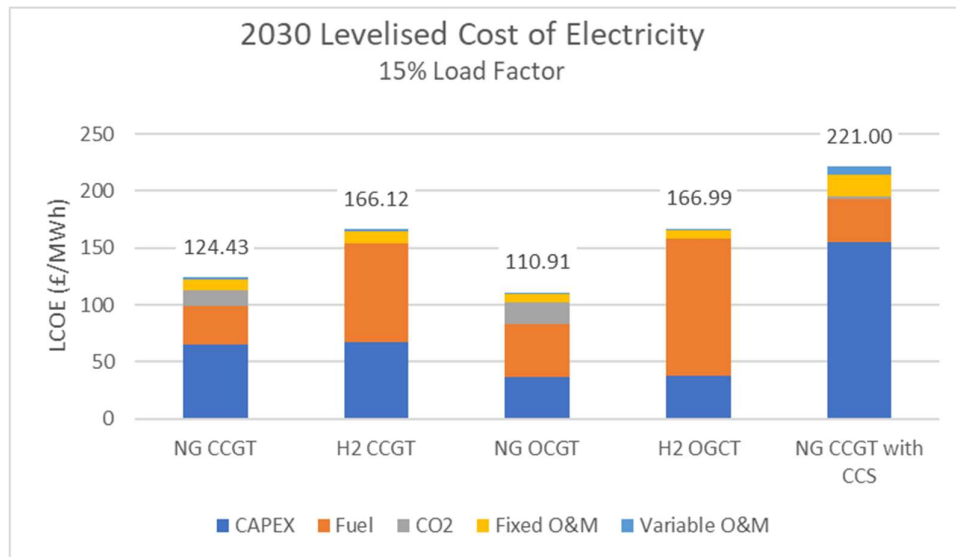


Figure 20: 2030 LCOE Base Case for 15% Load Factor

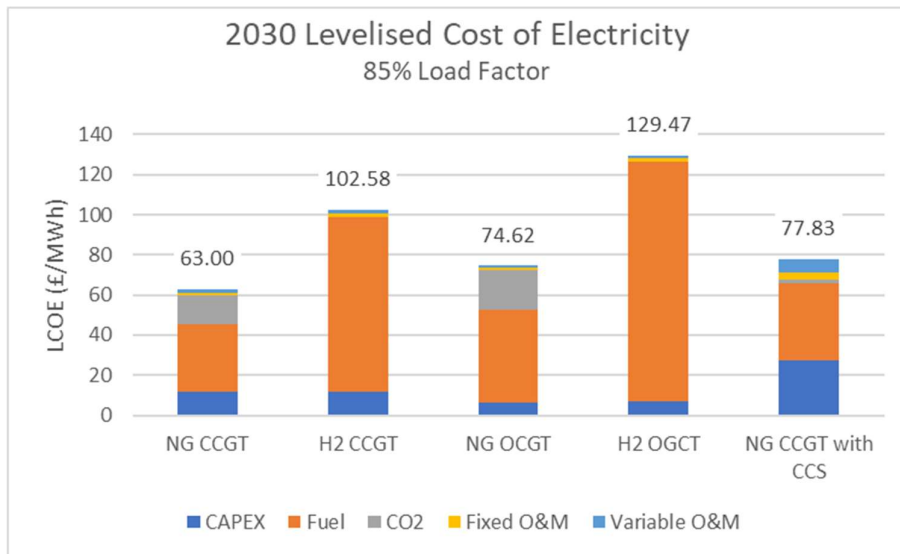


Figure 21: 2030 LCOE Base Case for 85% Load Factor

At both load factors at the carbon price of £42.66/tCO<sub>2</sub>, none of the low carbon technologies is able to compete with the natural gas references cases. The dominant factor for hydrogen turbines is the increase fuel price compared to natural gas. For gas CCS, the dominant factor is the CAPEX of the capture plant itself.

Comparing the hydrogen turbine options (CCGT and OCCT), both technologies have a similar LCOE of around £166/MWh at the lower load factor. However, at 85% load factor, the CCGT option is favourable with an LCOE £27/MWh cheaper than its OCCT counterpart.

Similarly, at 15% load factor gas CCS is significantly more expensive than hydrogen turbines with an LCOE of £221/MWh. This is due to the higher CAPEX of gas CCS being distributed over less electricity production. However, at higher load factors Gas CCS has a £52/MWh advantage over a hydrogen CCGT with an LCOE of £77.83/MWh.

#### 4.4.2.3 NOAK Base Case

As seen in Sections 4.2.8 and 4.3.8, cost reduction and efficiency improvements are anticipated for NOAK technology.

The following assumptions have been made for the NOAK base case with further explanation below:

- Year of commissioning - 2035
- Natural gas price - £21.84/MWh
- Hydrogen price - £35.62 MWh (HHV)
- Carbon price - £42.66/tCO<sub>2</sub>

By 2035, BEIS predicts natural gas prices to have risen to between 43 and 88p/therm with a central prediction of 64p/therm (103) – equivalent to £21.84/MWh. This natural gas price is predicted to then remain level until 2040.

By 2035, the build programme of HyNet expects to expand capacity to five units and, hence, deliver a lower levelised cost of hydrogen - £35.62/MWh (HHV basis) (31). On a LHV basis, this is calculated to be £42.10/MWh (106).

BEIS assumes the carbon price will remain level from 2030 onwards due to uncertainty around projections and policy mix in the long term (104). As such, the central 2035 prediction remains at £42.66/tCO<sub>2</sub> (104).

The LCOE for each technology (including natural gas reference cases) is shown in Figure 22 and Figure 23 for 15% and 85% load factors respectively. Even with the anticipated improvements of the low carbon technologies (and reduction in hydrogen fuel price and increase in natural gas price) (107), cost parity is still not reached with the reference case. Gas CCS comes the closest at a 85% load factor dropping to £75.84/MWh, but this is still above the reference cost of £65.54/MWh for a NG CCGT.

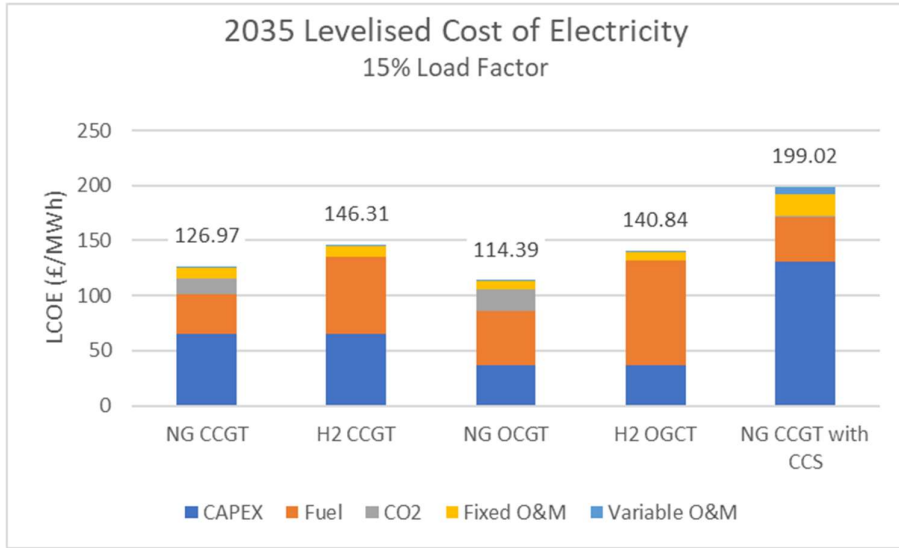


Figure 22: 2035 Base Case for 15% Load Factor

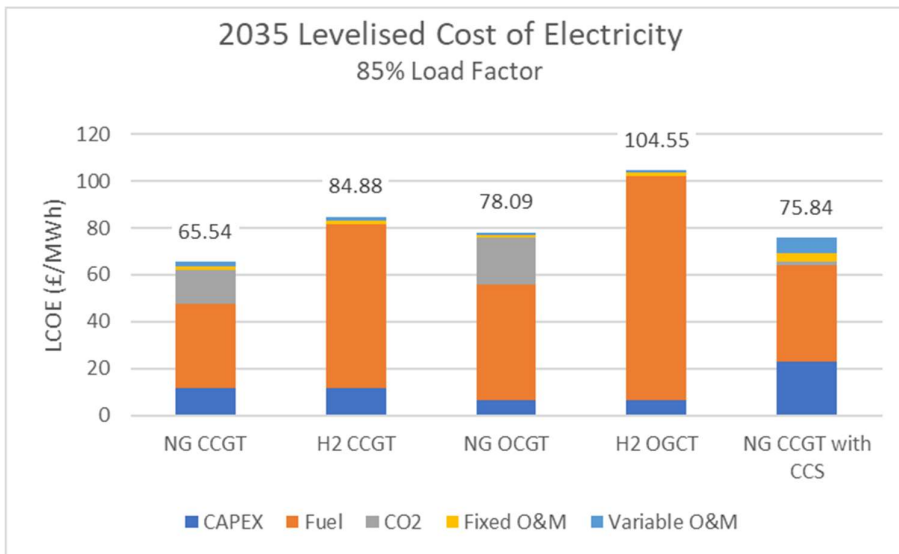


Figure 23: 2035 Base Case for 85% Load Factor

There is an improvement for all low carbon technologies between the FOAK and NOAK cases as shown in Figure 24 and Figure 25.

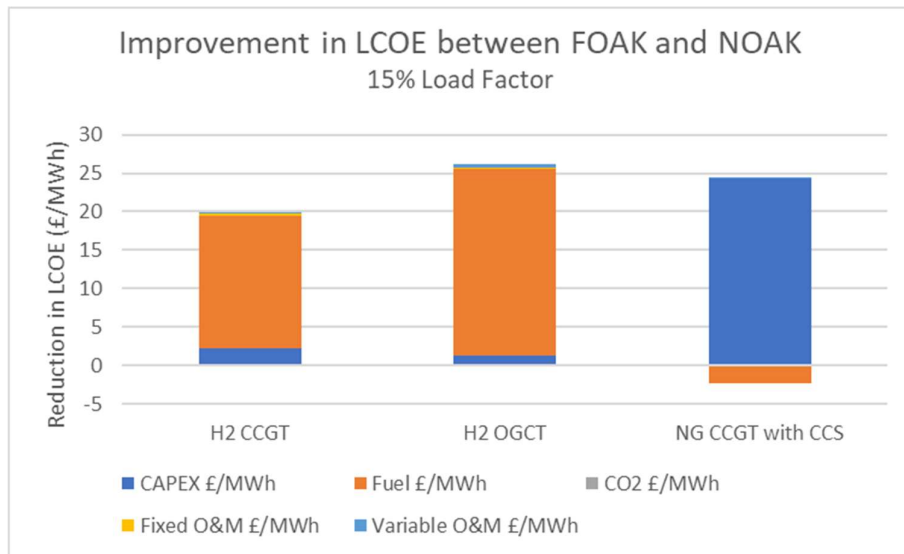


Figure 24: Reduction in LCOE between FOAK and NOAK Cases at 15% Load Factor

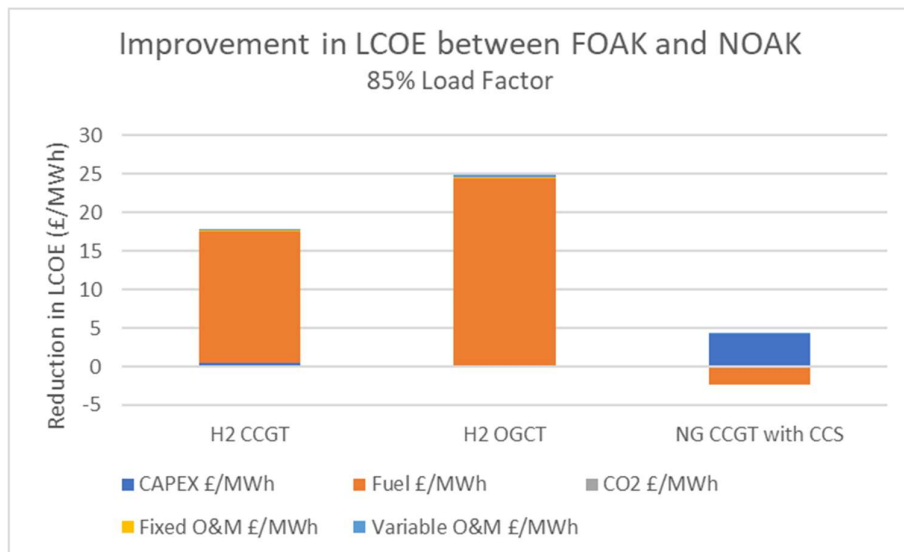


Figure 25: Reduction in LCOE between FOAK and NOAK Cases at 85% Load Factor

As it can be seen from Figure 24 and Figure 25, the reduction in LCOE for NG CCGT with CCS mainly comes from the 30% CAPEX reduction mentioned in Section 4.2.8.1.

For hydrogen, the reduced fuel price as HyNet increases production capacity has the biggest impact. The quantity of fuel required also decreases due to efficiency improvements in the gas turbine. However, these combined effects are insufficient to cancel out the higher fuel cost compared to natural gas.

### 4.4.3 High Efficiency CCGT

In order to consider a typical 400 MW plant, an F-class machine was used as the basis for the CCGT but a higher efficiency H-class machine was used for the OCGT. As such, another case for LCOE under 2035 assumptions (NOAK base case) has been considered using an H-class machine for the CCGT with a higher output of 880MW and efficiency of 64.1% as shown in Table 9.

The results are shown in Figure 26 and Figure 27.

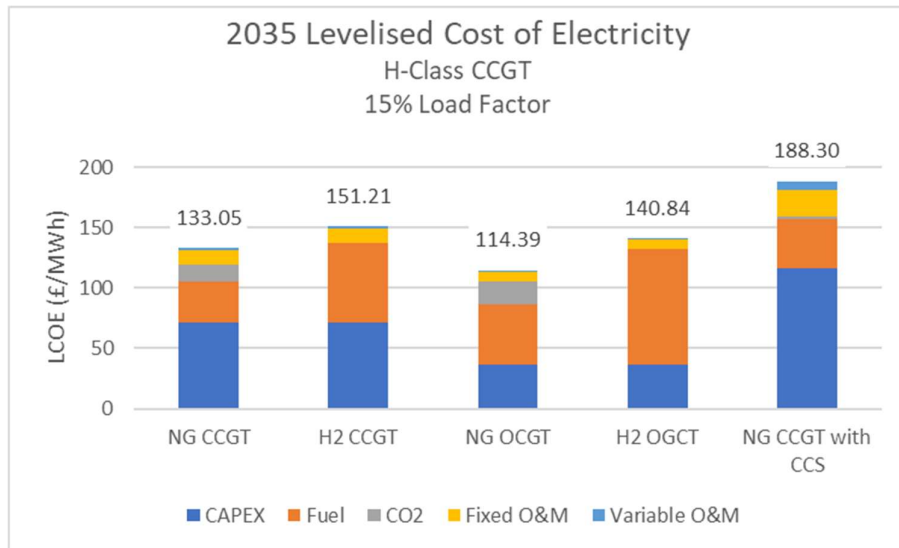


Figure 26: 2035 LCOE for H-Class CCGT at 15% Load Factor

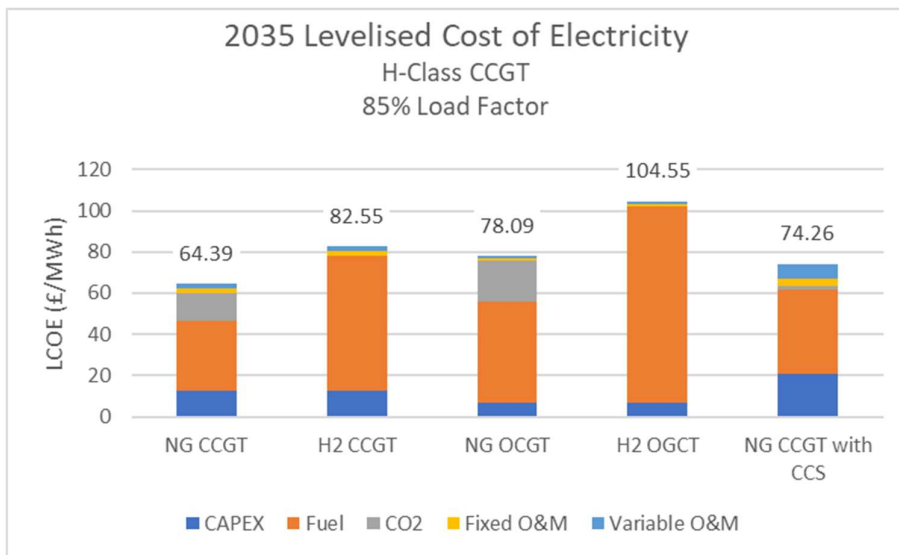


Figure 27: 2035 LCOE for H-Class CCGT at 85% Load Factor

A comparison of these LCOEs to the ones discussed above is shown in Figure 28.

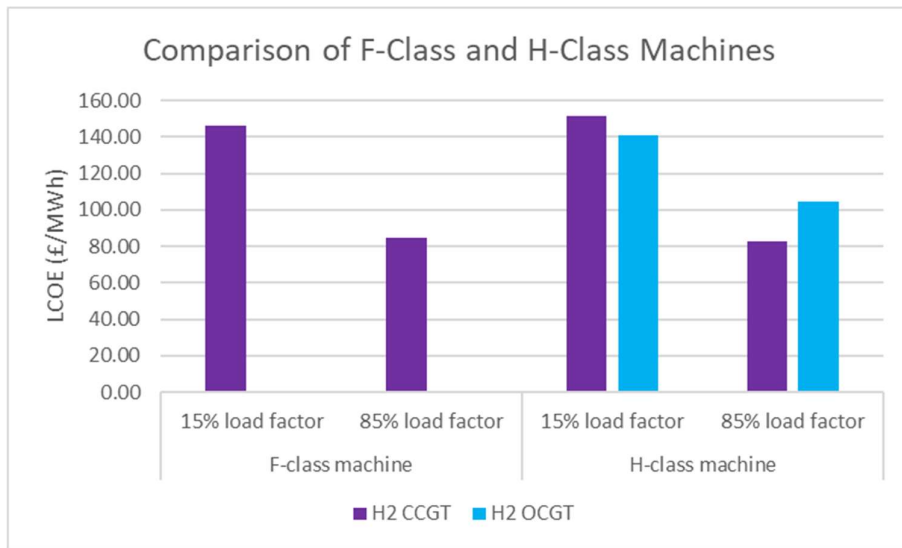


Figure 28: 2035 LCOE Comparison of CCGT Types

As it can be seen in Figure 28, the higher CAPEX of an H-class machine create a higher LCOE at low load factors. However, at higher load factors, the higher efficiency results in a slightly lower LCOE. The conclusions between CCGT and OCGT remain the same – OCGT having a lower LCOE at lower load factors and CCGT at higher load factors.

4.4.4 CO<sub>2</sub> Avoidance Cost

CO<sub>2</sub> Avoidance Cost (CAC), also known as CO<sub>2</sub> abatement cost, can also be used to compare the technologies. This is expressed in £/t CO<sub>2</sub> and is the additional cost spent to abate one tonne of CO<sub>2</sub> compared to the reference case. CAC can be calculated using the following formula (108):

$$CAC_{tech} = \frac{LCOE_{tech} - LCOE_{ref}}{tCO_2/MWh_{ref} - tCO_2/MWh_{tech}}$$

For post-combustion capture and hydrogen CCGTs, the reference case is taken to be a NG CCGT. In order to compare like against like, a NG OCCT is used as the reference case for hydrogen OCCT.

The results across all the base cases are shown in Figure 29. In line with the LCOE results discussed above, Gas CCS in the NOAK case with a 85% load factor offers the lowest CAC - £34.61/t CO<sub>2</sub>.

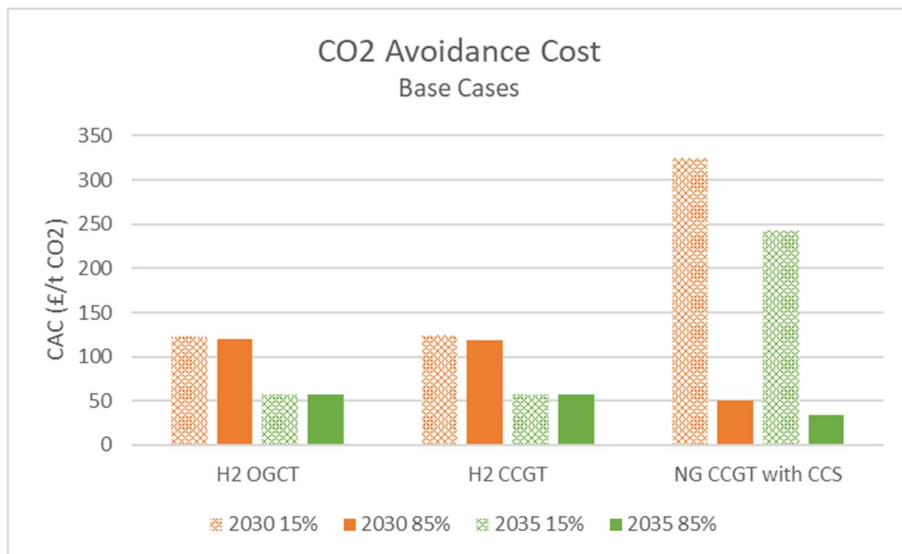


Figure 29: CO<sub>2</sub> Avoidance Cost

### 4.4.5 Load Factor

As described later in this report, there is huge disparity in energy scenarios on predictions of load factors of dispatchable power technologies. Each scenario prioritises different technologies and technology penetrations. Load factors vary between 0.22% and 91.26% for hydrogen turbines and 0.46% and 99.20% for Gas CCS.

Consequently, a sensitivity analysis of the effect of load factors (between 5 and 100%) on LCOE was carried out as shown in Figure 30 and Figure 31.

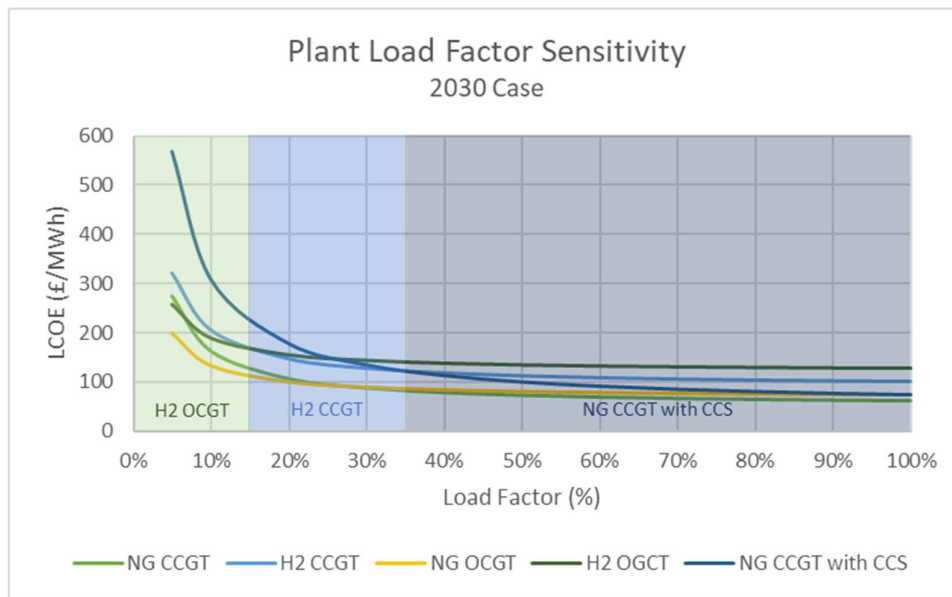


Figure 30: Plant Load Factor Sensitivity (2030)

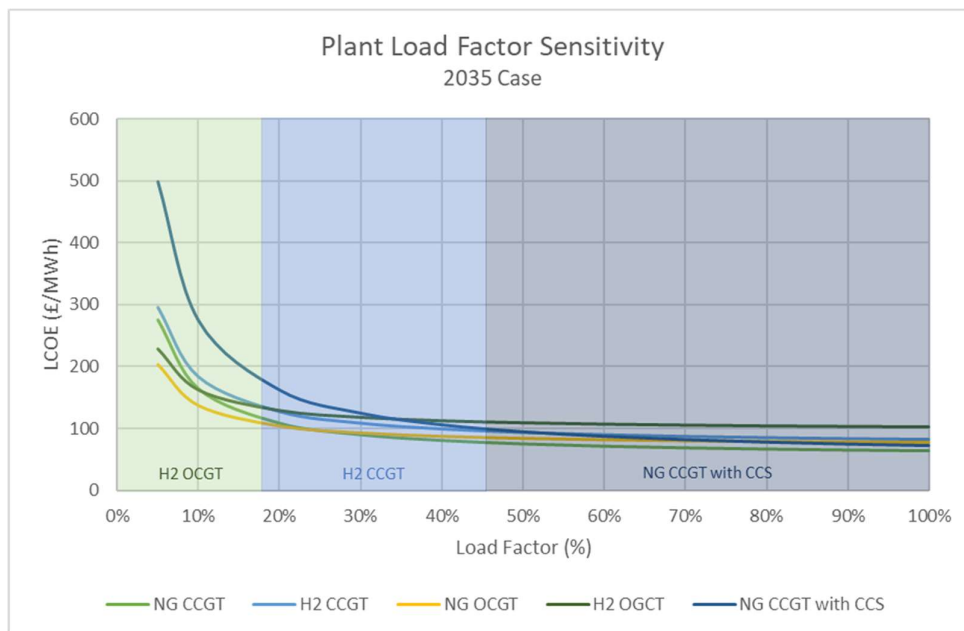


Figure 31: Plant Load Factor Sensitivity (2035)

In both graphs, the lowest low-carbon technology in a load factor region is indicated by shading. In both cases at very low loads (below roughly 15% load factor) a hydrogen OCCT is the cheapest low carbon technology. However, above this hydrogen CCGTs become cheaper than this option. Above 35-45%, Gas CCS is the cheapest low carbon technology to dispatch. Across the whole range of load factors, none of the low carbon technologies reach cost parity with the natural gas reference technologies.

The National Grid Future Energy Scenarios (FES) Consumer Transformation scenario predicts that upon introduction hydrogen turbines will operate with a load factor of 31.67% which will drop to 21.52% five years later (6). For Gas CCS, the Committee on Climate Change Balanced Net Zero Pathway predicts load factor will start at 68.64% and drop to 34.50% (5). The LCOE for these indicative values is shown in Table 16.

Table 16: LCOE at Predicted Load Factors

	2030		2035	
	Predicted Load Factor	LCOE (£/MWh)	Predicted Load Factor	LCOE (£/MWh)
<b>H<sub>2</sub> CCGT</b>	31.67%	125.51	21.52%	123.71
<b>H<sub>2</sub> OGCT</b>	31.67%	143.01	21.52%	127.49
<b>NG CCGT with CCS</b>	68.64%	85.14	34.50%	114.48

#### 4.4.6 Carbon Price

There is a variation in the carbon price predictions from BEIS between £0/tCO<sub>2</sub> and £84.61/tCO<sub>2</sub> across low, central and high scenarios between now and 2035 (104). As such, a sensitivity analysis was carried out on carbon prices between these two points in order to find the break-even point for each technology as shown in Figure 32.

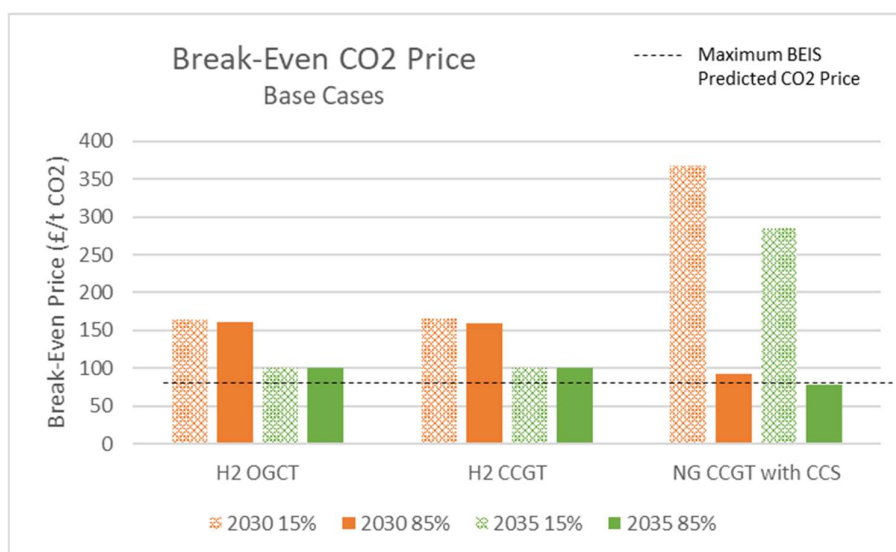


Figure 32: Break Even CO<sub>2</sub> Price

As can be seen in Figure 32, the break-even price for hydrogen turbines does not drop below £100/t CO<sub>2</sub> in the base cases. However, Gas CCS does just drop into the range predicted by BEIS at a high load factor (85%). As such, it can be concluded that it is credible that Gas CCS may become cost

competitive with its unabated counterpart before 2035 if run at high load factors and carbon prices track above the BEIS central predictions.

#### 4.4.7 Hydrogen Price

As a future market, there is uncertainty around hydrogen price. As such, a sensitivity has been carried out to determine at what price hydrogen turbines become cost competitive with their natural gas counterparts. The results are shown in Figure 33.

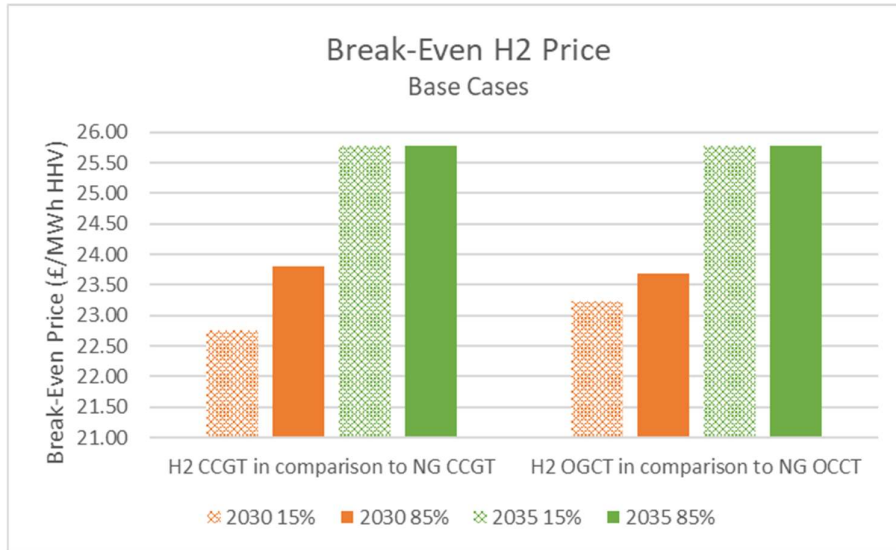


Figure 33: Break-Even Hydrogen Price Against Unabated Natural Gas

In the NOAK case, a hydrogen price of £25.77/MWh would be required. This is 28% lower than HyNet expects to deliver at full build (£35.62/MWh). Hence, it can be concluded that both a low hydrogen price and high CO<sub>2</sub> price is required before hydrogen turbines are cost competitive.

In comparison to Gas CCS (the other low carbon option), a hydrogen price of between £31.02/MWh and £71.13/MWh is required in the various base cases as shown in Figure 34.

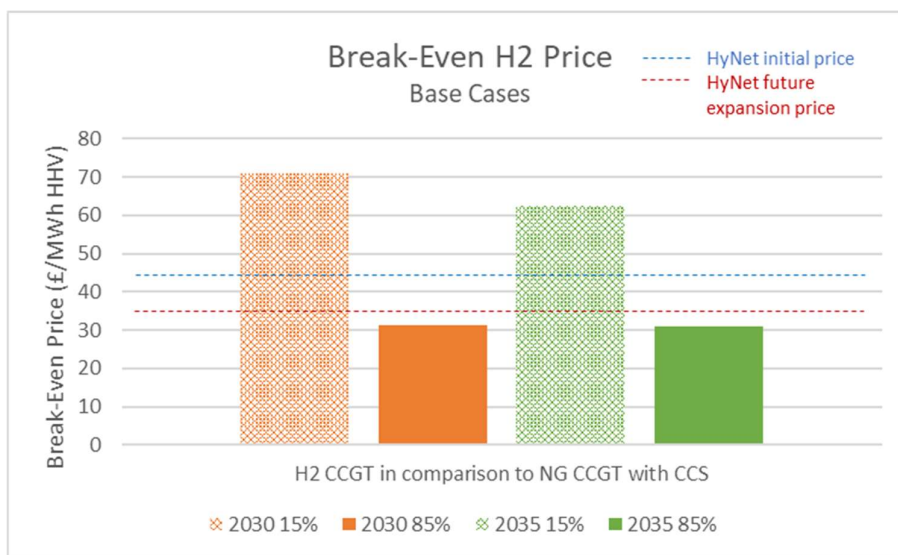


Figure 34: Break-Even Hydrogen Price Against Gas CCS

At low load factors, hydrogen prices do not need to be low for H<sub>2</sub> CCGTs to be competitive with gas CCS. However, this is under the assumption that hydrogen prices are set regardless of load factor (and hence quantity purchased from HyNet). In reality, it is likely that for lower load factors, the price per unit of hydrogen will be higher than a higher purchase order.

## 4.5 Comparison

Table 17: Comparison of 400 MW FOAK H<sub>2</sub> CCGT and Gas CCGT+CCS plants

		<b>Hydrogen CCGT</b>	<b>Gas CCGT with Post-Combustion CCS</b>
TRL		TRL 5/8 (combustion system dependent)	8-9
Efficiency		59% LHV basis	53% LHV basis
CAPEX		£323m	£655m
OPEX	Fixed	£5.3m/yr	£9.7m/yr
	Variable	£1.85MWh	£6.90/MWh
LCOE	15% LF	£166.12/MWh	£221.00MWh
	85% LF	£102.58/MWh	£77.83/MWh
Flexibility		Good grid load following and quick-start capability	Limited compressor turndown
Emissions (Scope 1)		0 tCO <sub>2</sub> /MWh [Note 1, 2]	0.052 tCO <sub>2</sub> /MWh
Infrastructure Requirements		Requires H <sub>2</sub> supply pipeline connected to salt cavern storage or multiple large hydrogen production units. May require alternative fuel supply (e.g., natural gas) for start-up and shut-down.	Requires natural gas pipeline from the grid and a transport and storage/utilisation network for CO <sub>2</sub> .

Note 1: There may be limited CO<sub>2</sub> emissions on start-up and shutdown if natural gas supply is required.

Note 2: This does not consider emissions from hydrogen production.

Please note that the numbers given in Table 17 are for FOAK developments based on the analysis given in previous sections. However, as evidenced throughout the earlier sections, the broad conclusions for NOAK developments remain the same.

## 4.6 Novel Technologies

As mentioned in Section 4.1, there a number of other technologies emerging as shown in Table 3.

### 4.6.1 Pre-combustion Capture

Hydrogen use within GTs, discussed in Section 4.3, can be considered to be pre-combustion capture in certain cases where hydrogen is produced on-site from a natural gas feedstock. However, the assumption is that for the North West, hydrogen will be available via the HyNet pipeline rather than produced on site.

As such, the efficiency (~59%) given in this report is the efficiency of hydrogen fuel to power and cannot be confused with round trip efficiency when compared to the Gas CCS or unabated NG option. If hydrogen was produced on site, the efficiency from natural gas to power would include a significant, additional efficiency penalty due to the reforming step. There would also be emissions associated with hydrogen production that have not been considered here.

Pre-combustion capture varies depending on the fuel being decarbonised. Integrated gasification combined cycle (IGCC) technology can be applied to solid fuels such as coal, solid waste and potentially biomass, whereas gas reforming technology can be applied to gaseous fuels.

In an IGCC plant, gasification takes place where a feedstock (such as coal) is partially oxidised in steam and oxygen or air at high temperature and pressure to form a synthesis gas (a mixture of H<sub>2</sub>, H<sub>2</sub>O, CO, CO<sub>2</sub>, COS and trace impurities). The “syngas” can then undergo the water-gas shift reaction to convert CO and water to H<sub>2</sub> and CO<sub>2</sub>, producing a H<sub>2</sub> and CO<sub>2</sub>-rich mixture. The CO<sub>2</sub> can subsequently be captured and transported for storage or utilisation, while the H<sub>2</sub> can be combusted in a combined cycle gas turbine (CCGT) to generate electricity. Unlike post-combustion capture where chemical solvents are favoured, the technology suited for pre-combustion capture is based on CO<sub>2</sub> absorption by physical solvents which offer significant cost and energy savings; this is because CO<sub>2</sub> is present at a higher partial pressure compared to the post-combustion capture case.

Syngas can also be produced by steam methane reforming (SMR) or partial oxidation of natural gas. For steam methane reforming, natural gas is heated at high temperatures in the presence of steam and a nickel-based catalyst inside a reformer, producing syngas, before the water gas-shift reaction occurs in a single shift reactor or series of shift reactors at varying temperatures which produces additional hydrogen. Subsequently, hydrogen is purified via pressure swing adsorption (PSA) or membrane technology while carbon oxides may be removed by the use of methanation. Analogous to the post-combustion capture process described in Section 4.2, carbon capture can be applied as an end-of-pipe solution to this process using an amine-based capture process that is also described in that section.

Partial oxidation of natural gas most commonly occurs via autothermal reforming (ATR). This features a stand-alone, oxygen-fired reformer containing a burner, a combustion zone, and a catalyst bed in a refractory-lined pressure vessel. Natural gas is reacted with steam and pure oxygen (partial combustion) to produce syngas, before further reforming takes place in the catalyst bed. The resulting H<sub>2</sub>-rich syngas can then be purified in the same way as the SMR process and CO<sub>2</sub> can be captured using an amine-based process. Hydrogen produced in this way using natural gas as a feedstock and with the application of carbon capture is known as “blue hydrogen”.

All the IGCC and reforming components have been demonstrated at an industrial scale by a wide variety of suppliers. However, the capital cost of IGCC and reforming technology is very high and there is a lack of experience in power generation compared to fossil-fired plants or post-combustion capture plants (109). Operational flexibility is also low, and cycle efficiency for power generation is lower with reforming-based capture than for post-combustion capture, which is a more demonstrated process.

### 4.6.2 Oxyfuel Capture

In oxyfuel combustion, coal or biomass is burnt in pure oxygen instead of air. This oxygen is produced in an air separation unit (ASU). The fuel is burnt in a supercritical boiler with oxygen and recycled (CO<sub>2</sub>-rich) flue gas which provides the inert material to limit the temperature in the boiler, with the CO<sub>2</sub> replacing the nitrogen that has been removed by the ASU. After a desulphurisation step, the flue gas contains only water vapour and carbon dioxide. The water is condensed out and the remaining CO<sub>2</sub> is liquified for transportation to a storage or utilisation site.

Because of the low C/H ratio of natural gas, oxyfuel technology is not currently a feasible option for gas-fired power generation. This is because oxyfuel combustion requires high levels of oxygen from an ASU, which is not used to generate CO<sub>2</sub>, but to generate mostly water. The energy consumed for oxygen production is lost in the resulting water which does not contribute to the reduction of CO<sub>2</sub>. Therefore, it is proposed that oxyfuel firing on natural gas applications is not an efficient use of energy, relative to the capture possible from higher carbon fuels (24).

Oxyfuel capture processes can, at least in principle, be retrofitted for power generation from coal or biomass, although this would significantly interfere with the core production processes at the candidate site. In addition, the ASU required for oxyfuel processes is highly cost and energy intensive.

Clean Energy Systems is developing oxyfuel GTs with water sprayed into the combustion chamber as dilutant. Their strategy is to modify proven gas turbines to gain relevant operating experience. In 2012 they rebuilt a second hand 32MW J-79 GT and in 2016 performed a feasibility study for use of biogas and extracting CO<sub>2</sub>.

Undertaking tests with modified GTs will be cheap, but use of the GT in this way may be sub-optimal with early trials showing high levels of CO<sub>2</sub>. The flexibility of the GTs was found to be low to medium.

The TRL of 6 suggests that this technology should be tracked. Any future development would be useful to note as oxyfuel GTs have the potential to be a zero emission technology in the future generation mix.

### 4.6.3 Small Modular Reactors

Small modular reactors (SMR) are nuclear reactors rated 300 MW<sub>e</sub> or less making them, by definition, smaller than grid-scale technologies to be considered here. A potential deployment option would be on brownfield sites, replacing decommissioned coal-fired plants (110). Benefits of the technology include no greenhouse gas emissions, large inertia and low fuel costs. A handful of SMRs are currently in operation, with more in development across the globe, the largest of which is a 300 MW CNP-300 located in Pakistan (111).

The problems associated with nuclear technology include radioactive waste management and resistance to its use, particularly in Germany. The technology has traditionally had low flexibility, and TRL varies between 5 and 8 depending on the technology used. The most common reactor type, the Pressurised Water Reactor (PWR) and the Pressurised Heavy Water Reactor (PWHR) are the technologies with the highest TRL, using water as the coolant in the reactor. Other technologies may use different cooling fluids, such as helium, to withstand higher temperatures (112).

Due to their modularity, SMRs are inherently more flexible than large nuclear plants with ramp rates of at least 5% of maximum power per minute (113).

### 4.6.4 Supercritical CO<sub>2</sub> Brayton Cycles

These power plant use supercritical CO<sub>2</sub> (sCO<sub>2</sub>) as the working fluid in a Brayton cycle instead of steam or water. This has the potential to improve efficiency of the cycle as well as providing a use for CO<sub>2</sub> emissions in a closed loop.

Sandia is working on a 10 MW<sub>e</sub> demonstration plant (114) and the US Department of Energy (DOE) has funded multiple research and development projects (115). The scale of these plants is too small to

be considered grid-scale and TRL depends on scale and technology, ranging between 5 and 7. However, with development, this could be a potential alternative to the Rankine cycle in boilers or nuclear reactors, with a higher efficiency above 550°C.

#### 4.6.5 Hydrogen Internal Combustion Engines

Internal combustion engines can be run using hydrogen as the fuel to produce electricity. Small businesses, such as The Pure Energy Centre, currently provide conversion services for engines, reporting no CO<sub>2</sub> emissions and very low NO<sub>x</sub> (116). This technology has high flexibility but would be reliant on hydrogen infrastructure and may lead to high maintenance and operation costs. Although in a transport setting this has a TRL of 8, there is little information about this technology in the context of power generation as focus has generally been on transport applications. There may be potential for this as a backup technology in the future where H<sub>2</sub> fuel is readily available.

#### 4.6.6 Hydrogen Fuel Cells

Hydrogen fuel cells are devices that convert chemical energy, using hydrogen and oxygen, directly to electrical energy, producing water as a byproduct. There are six common technologies, some less suitable to power generation activity than others. The largest fuel cell power station in operation is a Phosphoric Acid Fuel Cell (PAFC) module made up of 114 440 kW modules (combined: 50 MW) of around 45% efficiency (117). Applications of this technology are generally at a smaller scale and often considered for transportation rather than power generation; large scale operation would rely on hydrogen storage and supply. However, the technology is a potential zero emission technology for the future, potentially providing flexible and reasonably efficient energy solutions with low maintenance costs.

#### 4.6.7 High Temperature Fuel Cells in Combined Cycles

High temperature fuel cells have the potential to be topping cycles within power plants when combined with GTs and HRSGs with high efficiencies. MHPs commercially launched MEGAMIE in 2017, a 250 kW Solid Oxide Fuel Cell (SOFC) with 52% efficiency (118). The technology has poor flexibility and research and development focus is on reducing performance degradation instead, which has historically been an issue with this technology.

FuelCell Energy are building carbonate fuel cell plants made up of 1.4MW, the largest of which produces 59 MW on five acres of land (119). Though the TRL of this technology is high at 8, the size of these developments is smaller than Uniper would want to consider for grid-sale operation.

#### 4.6.8 Smart Advanced Humid Air Turbine (Smart-AHAT)

A simple cycle GT using a recuperator to improve efficiency and recognised as a highly efficient alternative to GTs with a similar flexibility. It has potential for higher efficiencies, lower NO<sub>x</sub> emission, and greater flexibility than current CCGT plants. Reduction of NO<sub>x</sub> may result in higher CO emissions and optimum pressure ratios for the turbines are higher than existing CCGT plants without sequential combustion. Hitachi built a 3 MW unit, with a 40 MW test unit commissioned in 2016.

#### 4.6.9 CCGT with Exhaust Gas Recirculation

Exhaust gas recirculation (EGR) can improve the efficiency of a CCGT with CCS by increasing the CO<sub>2</sub> concentration in the exhaust gas, making it is easier to implement CCS with smaller and cheaper capture plants. However, there has been no known experimental validation, only paper studies. GE has looked into EGR on the GT24/26 family and other test projects are being funded or researched at Cranfield University (120), with others being studied by the DOE (121). However the TRL is currently at 4 and so tracking and monitoring of this technology will help to determine whether this will be a future solution for decarbonisation of a fleet.

#### 4.6.10 Allam Cycle

The Allam (or Allam-Fetvedt) cycle is a process invented by engineers R J Allam and J E Fetvedt. In this cycle, the natural gas is combusted with oxygen from an ASU, with some CO<sub>2</sub> from the exhaust being used to moderate the temperature. The combustion products, principally CO<sub>2</sub> and water, are expanded through a turbine, which produces the power via the generator. The turbine exhaust products are cooled, with the water being separated. The remaining CO<sub>2</sub> is pressurised, with some of the CO<sub>2</sub> being returned back to the combustor, and the remaining CO<sub>2</sub> being exported from site via pipeline for storage.

The test facility owned by NET Power validated the zero-emissions cycle in 2018. The footprint of this plant is a third of that of a comparable CCGT, and the CO<sub>2</sub> turbine is significantly smaller than the steam turbine from an equivalent sized plant. The TRL of 7 and prospect of future funding from DOE makes this an interesting technology to follow as testing and demonstration continues. However, inflexibility could be an issue.

#### 4.6.11 Wind Driven Thermal Pumping

Wind driven thermal pumping is a concept by WindTP allowing excess energy created from wind turbines to be stored by using this energy to compress gas in a close to isentropic process. This possibility offers a dispatchable form of wind energy. A patent for this technology was submitted in 2018 (122) but no recent activity has since been recorded and a TRL of 1 gives this technology a poor outlook for development in the near future. The problems associated at this stage are complex material challenges due to high pressure heat stores and large temperature variations.

#### 4.6.12 Ammonia Gas Turbines

As a potential zero-carbon energy storage or hydrogen transport vector, ammonia (NH<sub>3</sub>) is also gaining interest as a fuel for direct use in gas turbines. Most of the current work with direct ammonia combustion is occurring in academic research facilities such as Tohoku University in Japan (123) and Cardiff University in the UK (124). Ammonia combustion produces high levels of fuel-bound NO<sub>x</sub> emissions under certain conditions and thus a new combustion system is required rather than the DLE/DLN systems developed for natural gas and hydrogen. This combustor development is currently at TRL 4. Mitsubishi Power announced in March 2021 the development of the world's first direct-fired ammonia gas turbine to be commercialised by 2025 and will likely require an SCR for NO<sub>x</sub> reduction (125). In June 2021, GE also announced plans to collaborate with IHI in Japan to evaluate the use of ammonia as a gas turbine fuel (126)

## 5. Regulatory Review & Business Models

### 5.1. Current Regulation / Policy

#### Net zero and carbon budgets

In June 2019, the UK government amended the Climate Change Act 2008 (127) to adopt a legally binding target of reducing the UK's emissions to net zero by 2050; an increase from its previous target of a reduction of 80% compared to 1990 emissions.

In order to drive and track progress toward the net zero target, the government has adopted a series of interim carbon budgets (128): legally binding targets that are set with advice from the Climate Change Committee (CCC). In line with the CCC's recommendation for the 6th carbon budget covering the period 2033 – 2037, the government set into law a reduction of emissions of 78% by 2035 compared to 1990 levels. The government also accepted the CCC's advice to set a Nationally Determined Contribution of at least 68% (excluding International Aviation and Shipping emissions) by 2030 and has submitted that to the UNFCCC.

In November 2020, the government published a 'Ten Point Plan for a Green Industrial Revolution' (129), which included commitments on growing low carbon hydrogen production in the UK to 1GW by 2025 and 5GW by 2030, and investing in CCUS to support the development of two industrial clusters by the mid-2020s and four by 2030, capturing up to 10Mt CO<sub>2</sub> per year.

### 5.2. Revenue Models

#### 5.2.1. Gas with CCS for Power (DPA)

Within the four industrial clusters by 2030 ambition, the government has committed to supporting the deployment of at least one power CCUS project and to developing a commercial framework for future projects. The government has launched a CCUS Cluster Sequencing process, which is designed to select at least two transport and storage networks and a number of associated capture plants for support to enter into operation by the end of 2027. It proposes to support power CCUS operations through a bilaterally negotiated Dispatchable Power Agreement (DPA) (130).

The DPA is proposed to consist of two main elements: an availability payment for low carbon generation availability, and a variable payment to adjust the position of the power CCUS plant in the merit order so that it will run after renewables and nuclear but before unabated CCGT. It makes provisions for outages due to transport and storage unavailability, low capture rates, and force majeure events.

The DPA has not yet been finalised, and a further update is expected in the autumn. Key outstanding issues include the treatment of start-up costs, for which the government is not proposing to make specific provision, and contract duration.

It is not yet clear whether the DPA will be the basis of the commercial framework for future power CCUS plants outside of the Cluster Sequencing process.

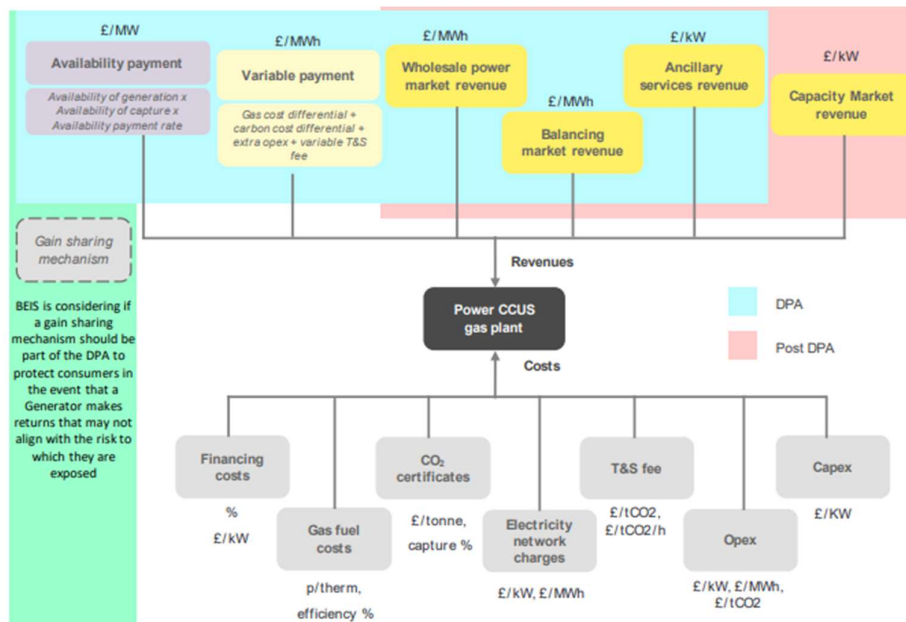


Figure 35 - a holistic view of the costs and revenues associated with a power CCUS plant and their structure of payment, reproduced from Figure 6 in (131)

### 5.2.2. Hydrogen for power

The government has recently published its Hydrogen Strategy, and three associated consultations on: a business model for hydrogen production; the Net Zero Hydrogen Fund; and a low carbon hydrogen standard (132).

The Strategy sets out a roadmap for the development of the UK hydrogen economy, moving from subsidy support, small scale production and limited use in industry and transport in the early 2020s, to a competitive and self-financing market with regional or national networks, large scale storage and a full range of end users from the mid-2030s. The Strategy presents analysis by BEIS for the 6<sup>th</sup> carbon budget, which suggests 250-460TWh of hydrogen could be needed in 2050, making up 20-35% of UK final energy consumption

This is based on a “twin track” approach, to capitalise on UK potential to produce significant quantities of both CCUS enabled blue hydrogen, and electrolytic green hydrogen.

The Strategy seeks to address both supply-side and demand-side challenges to growing the UK hydrogen economy through: capital and operational support for hydrogen producers; support and incentives for fuel switching in industry and transport; developing and testing new markets, such as hydrogen for heat in buildings; and consumer engagement.

The Hydrogen Strategy and consultations do not set out a business model for hydrogen for power, beyond the subsidy for hydrogen production that is intended to enable fuel cost parity with natural gas. The Dispatchable Power Agreement for CCUS power will support hydrogen power from co-located pre-combustion CCUS, but no other hydrogen for power operating models are currently provided for.

## 6. A future role for dispatchable power

### 6.1. Future Energy Forecasts

Future energy scenarios have, and continue to be developed by numerous public and private sector bodies and institutions across the globe. Based on an initial set of assumptions for each, these scenarios look to develop thinking and understanding, considering both single and multi-vector energy environments and modelling the potential outcomes. These outcomes provide an insight into the potential energy mixes of the future, helping to inform the decisions of today. More recently and aligned with the binding commitments being made by countries and unions, these scenarios have sought to forecast 'Net Zero' futures where the modelled environment targets net zero Carbon or total GHG emissions by 2050.

To inform the thinking behind the possible future role of low carbon dispatchable power, and therefore the potential opportunity in the North West and North East Wales, the following future energy scenarios were consulted and reviewed

1. National Grid - Future Energy Scenarios (133)
2. Climate Change Committee – Sixth Carbon Budget (134)
3. BEIS - Energy & Emissions Projections 2019 (135)
4. National Infrastructure Commission - Net zero: Opportunities for the power sector (136)

Both National Grid’s Future Energy Scenarios and CCC’s Sixth Carbon budget are whole system models, considering the entire energy landscape. The forecasts made BEIS and the NIC, however, consider only Electricity Generation.

#### 6.1.1. General Trends

In general, all forecasts see an increase in total electricity demand to 2050, with the 'Widespread Innovation' scenario detailed by the CCC, for instance, suggesting a 3 fold increase in annual electricity demand if including demand for electrolysis (137).

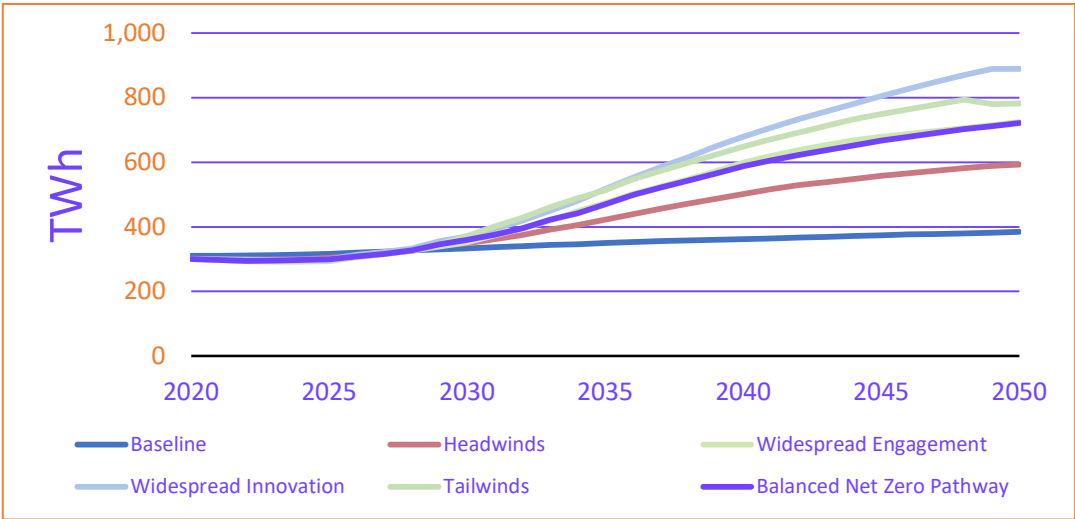


Figure 36 - Total UK electricity consumption including use of 'surplus' generation for electrolysis. Graph Reproduced from the CCC Sixth Carbon Budget Dataset (21),

The 2020 Future Energy Scenarios (FES) produced by National Grid ESO in general forecast an increase in the peak electricity demand (that seen on a cold winter’s weekday evening) through to the mid 2040s for all scenarios, with a 30-50% increase being suggested. Only 'Leading the Way' shows the beginning of a reduction in peak demand after this point. It is also detailed by National grid in their 'Consumer Transformation' scenario that up to 2.8 times more generating capacity may be required in 2050 compared to today.

Although in general agreeing on the increase in demand for electricity in future years, there is significant variation across the models and scenarios when considering the generation technology mix. In order to reach Net Zero by 2050, it is clear that a significant increase in the installed capacity of renewables will be required and this is reflected by all scenarios. The level of penetration, however, varies. The NIC, for instance, model scenarios with up to 90% total electricity generation from renewable sources (136), an enormous increase compared to 37.1% penetration recorded in the UK in 2019 (1).

With such high levels of renewable penetration comes significant variability in available or delivered power by these technologies. It is therefore necessary that the remaining generation mix provides suitable levels of both capacity but also flexibility and dispatchability. In order to ensure such security of supply, the scenarios deploy a mix of firm/inflexible power generation, flexible/dispatchable generation and interconnectors. Again, however, depending on the specific assumptions applied, the role technologies play may differ with the same technology operating in base-load in one scenario and flexibly in another.

It should also be noted that in addition to variation of demand forecasts, energy mixes and technologies across models and scenarios, there is also variation shown year on year as the thinking and assumptions evolve.

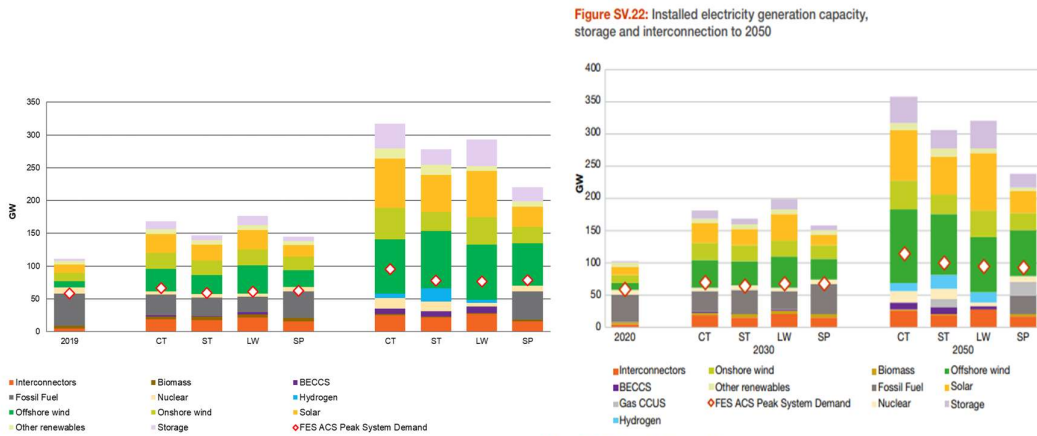


Figure SV.22: Installed electricity generation capacity, storage and interconnection to 2050

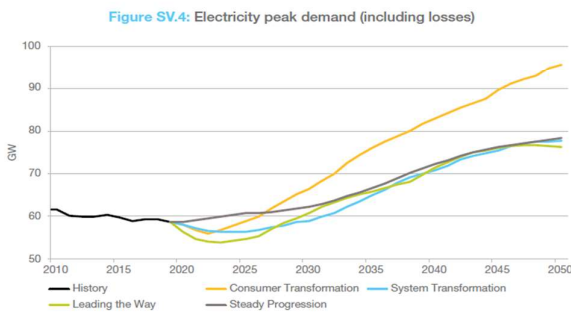


Figure SV.4: Electricity peak demand (including losses)

Figure FL.4: Electricity peak demand

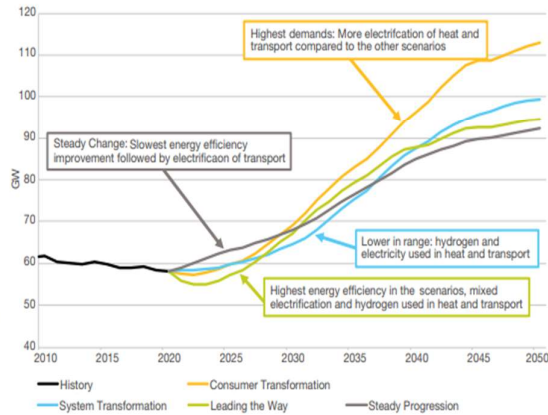


Figure 37 - Graphs from the 2020 and 2021 National Grid Future Energy Scenarios (6) (138), showing the variation in predicted installed generating capacity and peak demand

Figure 38 shows a comparison of the forecast trends in the 2020 and 2021 National Grid Future Energy Scenarios. Although similar, it can be seen that both Demand and generating capacity forecasts have increased from the 2020 predictions to 2021. For the peak demand forecast for the Consumer Transformation scenario, this increase is significant, at almost 20%.

It should, therefore, be noted that the modelling data and resulting outputs/scenarios can only be considered as potential future scenarios and only relevant as long as the initial input assumptions and datasets hold true

**6.2. Dispatchable Low Carbon Generation**

The four energy system models consider the need for ‘dispatchable’ power generation and define a mix of technologies to deliver the required low carbon flexible power. Across the scenarios, there is a range of technologies deployed, with the most prominent contributors being Hydrogen Turbines, Gas Turbines with CCS, Biomass and Bioenergy with CCS (BECCS). The contribution of these technologies is presented in Table 18, reproduced from Table 4. This shows a high potential for Hydrogen Turbines and Gas Turbines with CCS to play a vital role in delivering dispatchable, flexible power in a Net Zero future.

*Table 18 - Low Carbon Dispatchable Power Technologies as deployed in the various Future Energy Scenarios*

	<b>Climate Change Committee, The Sixth Carbon Budget [2]</b>	<b>National Grid Future Energy Scenarios [3]</b>	<b>BEIS Energy and Emissions Projections [4]</b>	<b>National Infrastructure Commission [5]</b>
<b>Hydrogen Turbines</b>	Considered ‘Dispatchable’	Considered ‘Dispatchable’	Considered ‘Dispatchable’	Considered ‘Dispatchable’
<b>Gas with Post-Combustion Carbon Capture Utilisation and Storage (CCUS)</b>	Considered ‘Dispatchable’	Not cost efficient in comparison to hydrogen turbines	Considered ‘Dispatchable’	Considered ‘Dispatchable’, but could be displaced by hydrogen turbines
<b>Bioenergy with CCUS (BECCS)</b>	Considered ‘Dispatchable’	More likely to operate at base load	Insufficient biomass anticipated	More likely to operate at base load
<b>Biomass Generation</b>	Limited supplies more likely to be used for BECCS or as a fuel in other sectors	Considered ‘Dispatchable’	Insufficient biomass anticipated	Limited supplies more likely to be used for BECCS

All scenarios from the 4 forecasts were mapped onto a single sheet to display the range of capacity and generation forecasts predicted. The mapped information is as follows;

**Climate Change Committee**

All 5 scenarios were mapped, including;

- Balanced Net Zero Pathway
- Headwinds
- Widespread Engagement
- Widespread Innovation
- Tailwinds

**National Grid – Future Energy Scenarios**

All 4 2020 scenarios were mapped, both to show total capacity/generation (All), but also only transmission connected (Trans).

- FES Consumer Transformation ALL
- FES Leading the Way All
- FES Steady Progression All
- FES System Transformation All
- FES Consumer Transformation Trans
- FES Leading the Way Trans
- FES Steady Progression Trans

- FES System Transformation Trans

All 4 2021 scenarios were also mapped, but only for total system contribution

- FES Consumer Transformation 2021
- FES Leading the Way 2021
- FES Steady Progression 2021
- FES System Transformation 2021

### **BEIS Energy & Emissions Prediction 2019**

Only the Net Zero scenarios were mapped, both for High and Low demand but also both for all generators and only MPPs

- BEIS NZ High demand All
- BEIS NZ Low demand All
- BEIS NZ High demand MPPs
- BEIS NZ Low demand MPPs

### **National Infrastructure Commission**

3 main scenarios were mapped, the baseline Net Zero scenario (NIC), but also 2 which consider electricity production from Hydrogen. In one instance hydrogen generated from gas reforming with CCS is burnt in hydrogen turbines (NIC Reform) and in the other, hydrogen produced from electrolyzers using curtailed generation is used (NIC Electrol). Each of these is then modelled in the situation where firstly, heating demand is electrified and secondly where this is provided by green gasses (shown by Elec/H2 in the below). Finally this subset is further split to reflect a renewable penetration of 60, 80 and 90% (shown by 60, 80, 90 in the below). This creates a total of 18 separately modelled scenarios;

Baseline Model

- NIC Elec 60, NIC Elec 80, NIC Elec 90
- NIC H2 60, NIC H2 80, NIC H2 90

Power from Green Hydrogen

- NIC Electrol Elec 60, NIC Electrol Elec 80, NIC Electrol Elec 90
- NIC Electrol H2 60, NIC Electrol H2 80, NIC Electrol H2 90

Power from Blue Hydrogen

- NIC Reform Elec 60, NIC Reform Elec 80, NIC Reform Elec 90
- NIC Reform H2 60, NIC Reform H2 80, NIC Reform H2 90

#### **6.2.1. Collated Trends**

The following graphs show the collated outputs from the above scenarios, displaying Capacity, Generation and calculated load factor. It is clear from first view that there is a significant range in the forecasts made by each scenario, both in terms of the magnitude and trend. There do, however, exist a few similarities or commonalities; these are discussed below.

6.2.1.1. Electricity Generation from Hydrogen Turbines

It can be seen that there is a great variation in the predicted capacity of Hydrogen Turbines across the scenarios, ranging from zero to upwards of 40GW by 2050. A commonality across all scenarios, however, is the upward trend commencing at or around 2030.

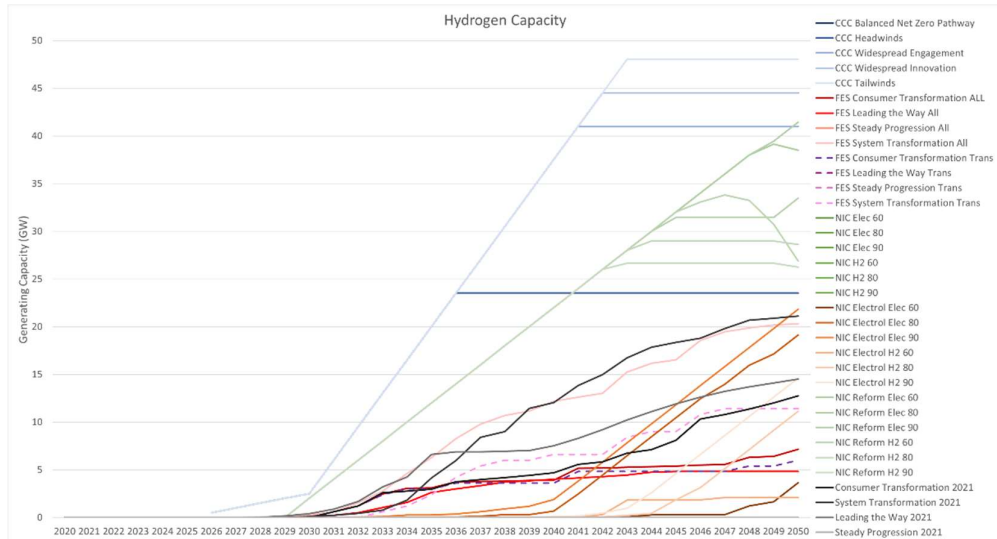


Figure 38 - Graph to show compiled generating capacity for Hydrogen Gas Turbines in the UK across all mapped scenarios<sup>1</sup>

Generation volume again differs significantly across the scenarios, from a fraction of a TWh to over 240TWh. Electricity generation from Hydrogen does, however, seem to peak in the early to mid 2040s in many of the scenarios from CCC, NIC and NGESO. This, in most cases, is explained by a growing level of renewables penetration coupled with significant energy storage and smart grids and in some cases greater deployment of nuclear, all combining to reduce the dependence on hydrogen turbines as dispatchable assets.

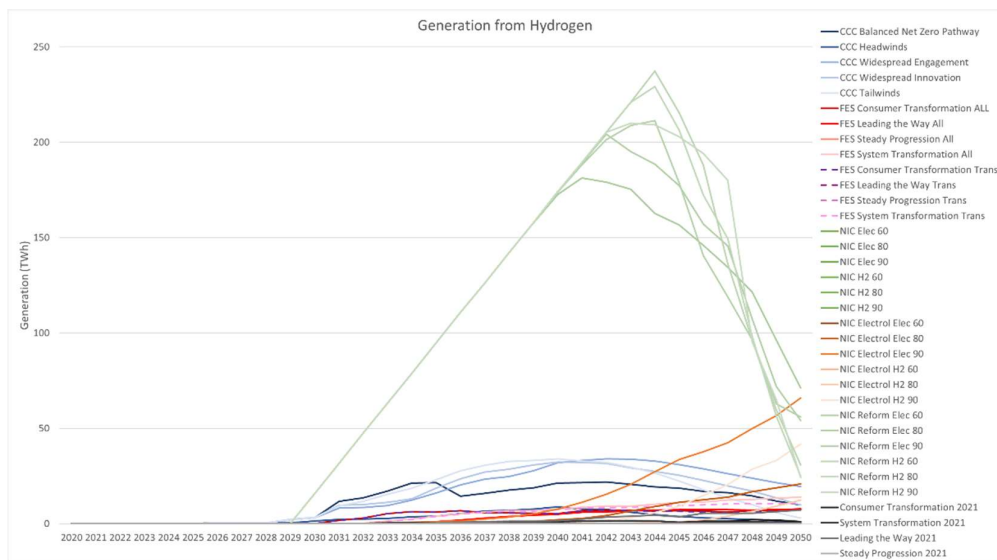


Figure 39 - Graph to show compiled electricity generation from Hydrogen Turbines in the UK across all mapped scenarios

<sup>1</sup> Generation capacity for CCC scenarios has been based on qualitative statements with the 6<sup>th</sup> Carbon Budget report, rather than defined, provided values

Load factors were calculated from the above data using the following;

$$Load\ Factor = \frac{Generation\ Volume}{Capacity * 365.25 * 24}$$

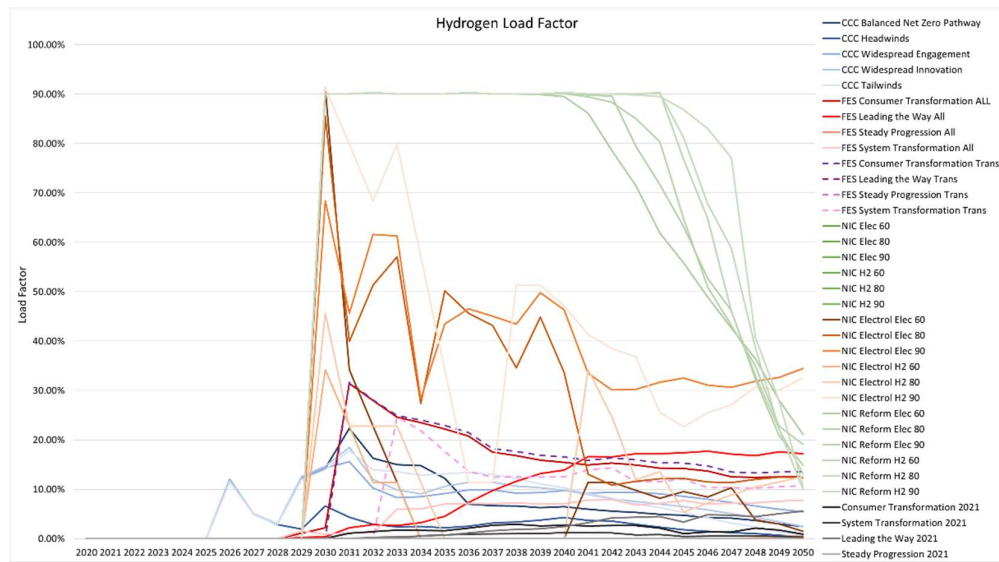


Figure 40 - Graph to show compiled load factors of Hydrogen Turbines for the UK across all mapped scenarios

It can be seen that again there is again no correlation between the scenarios when considering load factor, with there being a range from highly dispatchable profiles with a load factor of <10% through to almost base load operation where using only Hydrogen reformed from natural gas.

The significant base load operation seen across the NIC scenarios deploying Hydrogen from gas reformation is due to their modelling suggesting this to provide lower cost power when compared to both Nuclear and gas CCS. It therefore displaces these technologies providing both baseload, but also flexible power at low cost. From 2040 onwards, much of this generation is then replaced by additional Off-shore wind and/or nuclear, proving true Zero carbon power.

6.2.1.2. Electricity Generation from Gas Turbines with CCS

Similar to the trends shown for Hydrogen turbines, there is a significant range of capacity predictions for Natural Gas Turbines with CCS. Almost all trends show capacity growing towards 2050, however, total capacity in 2050 ranges from 0GW to almost 25GW.

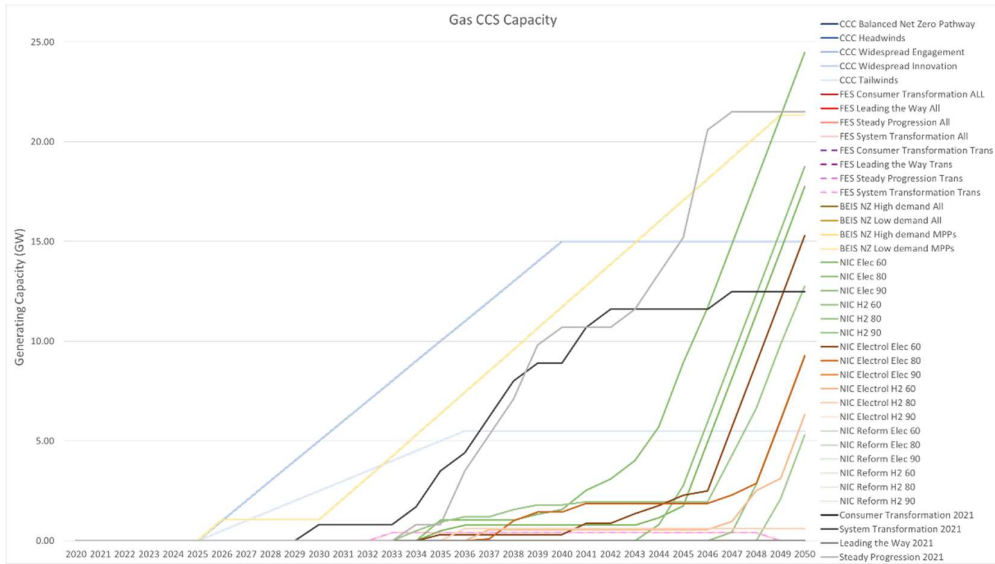


Figure 41 - Graph to show compiled generating Capacity for Natural Gas Turbine with CCS in the UK across all mapped scenarios

This is reflected by the generation forecasts, again showing on average a general increase towards 2050, but with final volumes ranging from 0 to almost 80TWh

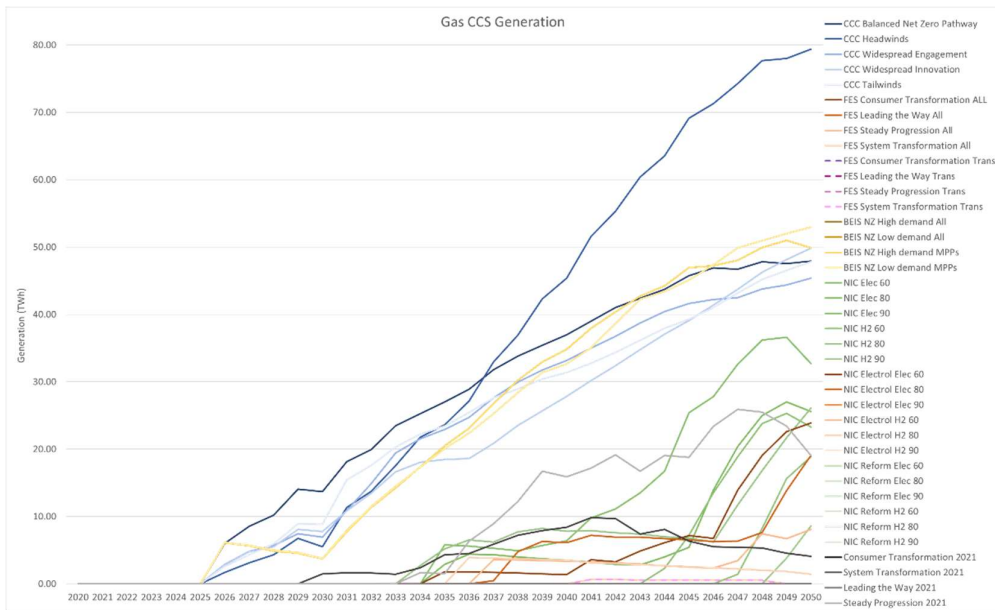


Figure 42 - Graph to show compiled electricity generation from Natural Gas Turbines with CCS in the UK across all mapped scenarios

Apart from the CCC scenarios (where load factor increased towards 2050), it can be seen that in many scenarios' load factors are forecast to be greatest following initial commission of the Gas CCS assets, then steadily reducing towards 2050

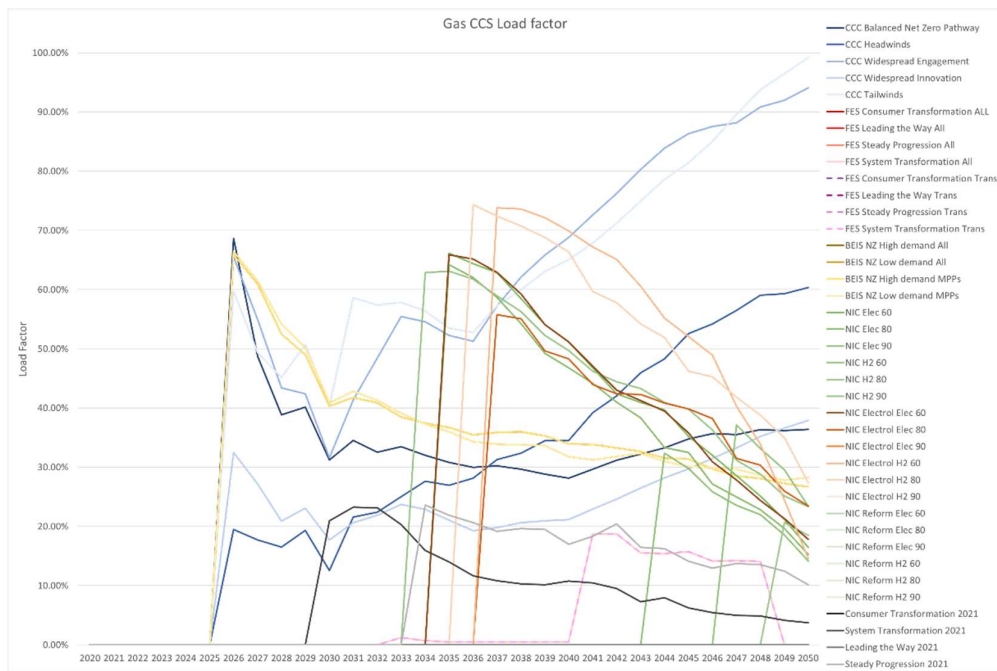


Figure 43 - Graph to show compiled load factors of Natural Gas Turbines with CCS in the UK across all mapped scenarios

6.2.1.3. Electricity Generation from dispatchable low carbon gas Turbines

So as to consider a holistic approach to dispatchable generation, the two technology contributions were combined, providing a view of 'dispatchable low carbon gas generation'. As can be seen in the following 3 figures, even the aggregated capacity, generation and load factors show little to no similarity across the scenarios.

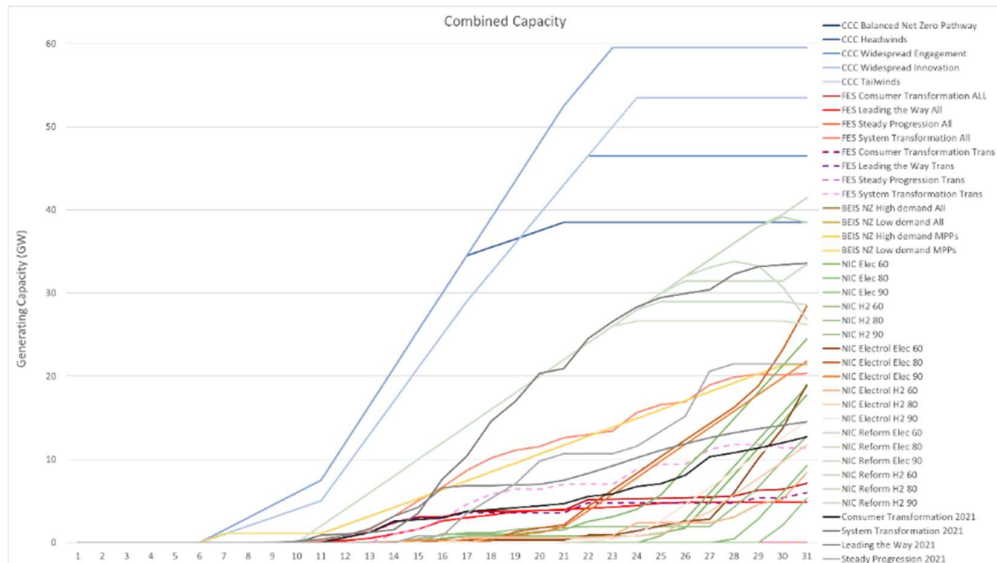


Figure 44- Graph to show compiled generating Capacity for Natural Gas Turbine with CCS and Hydrogen Gas Turbines in the UK across all mapped scenarios

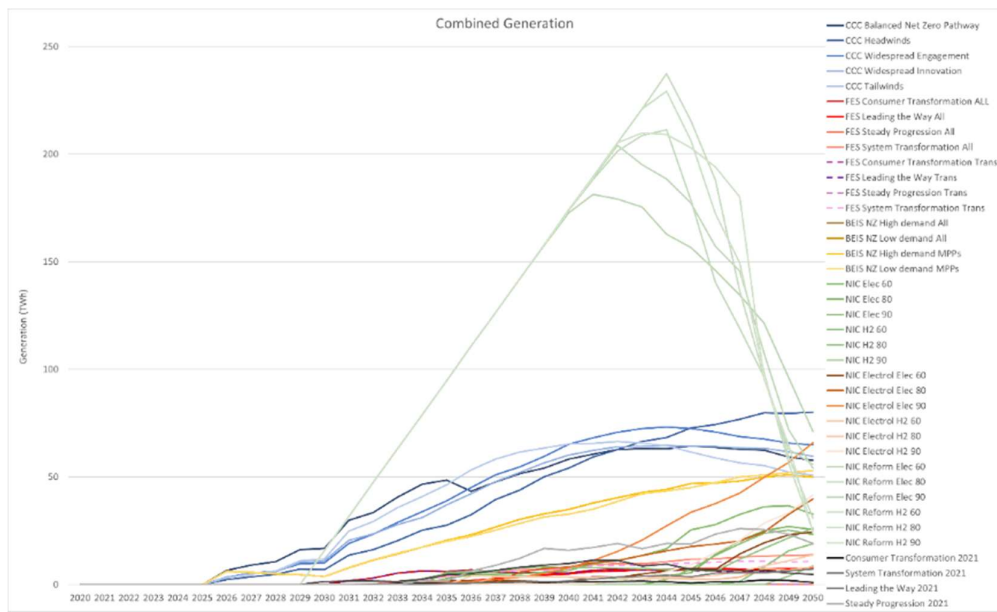


Figure 45- Graph to show compiled electricity generation from Natural Gas Turbines with CCS and Hydrogen Turbines in the UK across all mapped scenarios

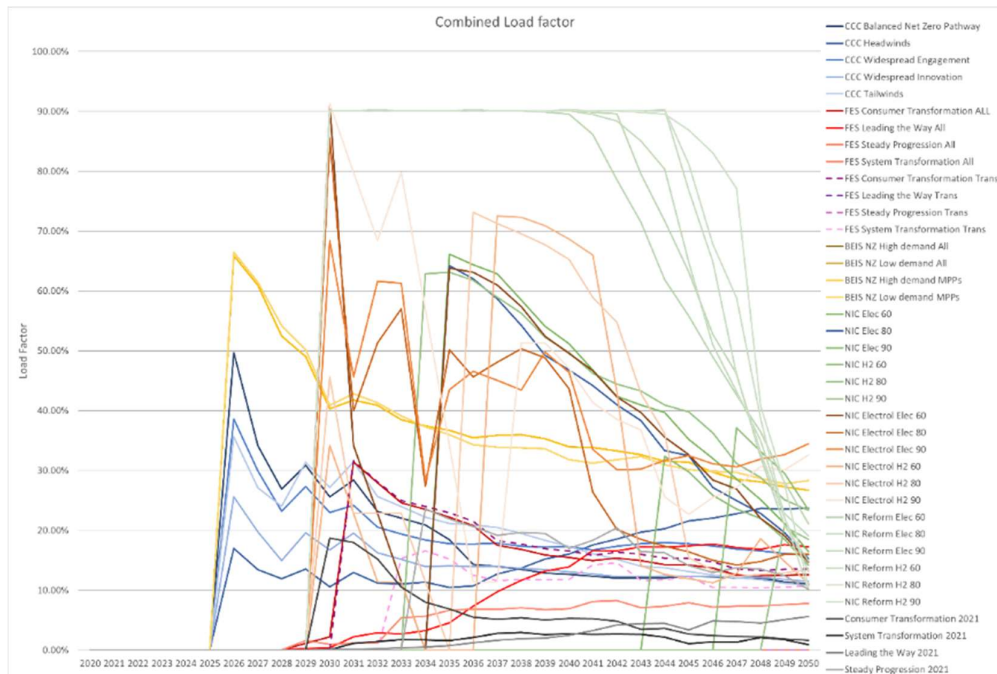


Figure 46- Graph to show compiled load factors of Natural Gas Turbines with CCS and Hydrogen Turbines in the UK across all mapped scenarios

### 6.3. Low Carbon Dispatchable power in the North West and North East Wales

#### 6.3.1. Possible Locations

Due to existing connections to the electrical transmission network and other key resources such as natural gas and water, and potentially easier planning considerations, it is likely that future >300MW low carbon dispatchable generation will be located on or local to existing or recently decommissioned Power Station sites. Considering the developing plans for the Carbon Dioxide and Hydrogen networks in the region and the expected requirement to connect into the ‘trunk’ mains of this network provides further indication of which technologies may be more likely in which areas.

Existing or recently decommissioned sites are shown in the image below, with the colour indicating more likely technology;

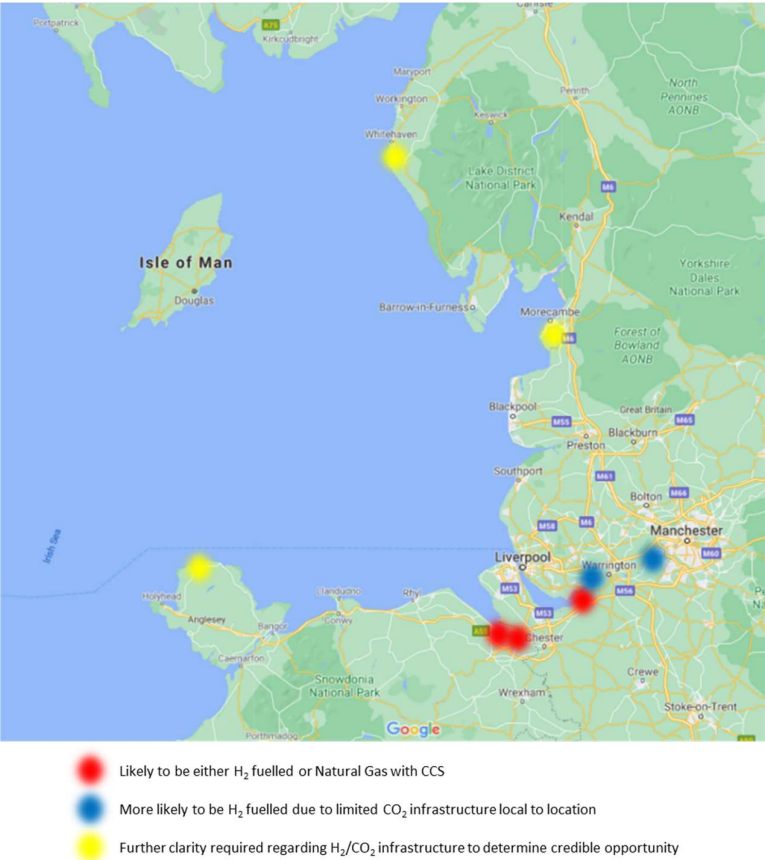


Figure 47 - Map to show possible locations of future low carbon dispatchable power assets

It should be noted, however, that there may be many more suitable locations than those shown in Figure 43, especially where the proposed technology type has reduced infrastructure connection requirements such as OCGTs (where no cooling water is required) or where they are of a smaller generating capacity.

It may also be the case that due to additional electrical capacity connecting into the transmission or distribution network, the sites highlighted above may become electrically constrained and therefore no longer suitable for large scale generation.

As such, this list should not be taken as comprehensive or confirmed. As with any new build major project, whether on a new site or re-planting a previous generating site, land availability, infrastructure connections, planning etc would need to be fully understood prior to further development and or commitment. Further work would therefore be required to better define possible and or probably locations.

### 6.3.2. H<sub>2</sub> Gas Turbines

#### 6.3.2.1 H<sub>2</sub> Gas Turbine Capacity and Generation

In order to feed hydrogen demand modelling developed being developed by project partners, it was necessary to provide a forecast for the potential deployment and utilisation of Hydrogen Gas turbines for Power in the North West region. Due to the significant variation in low carbon dispatchable generation forecast in the future energy scenarios, as detailed in section 6.2, determining a common vision for the UK and therefore for the North West and North Wales required extensive review and alignment with wider assumptions applied within the cluster.

To ensure background and wider project assumptions were reflected, and the broader energy system was considered, it was decided to associate the potential deployment of Hydrogen Turbines in the cluster area with the Consumer Transformation and System Transformation scenarios proposed by National Grid. Use of these scenarios ensured clear alignment to the Big Electric and Big Hydrogen scenarios being developed by project partners.

Due to the constraints placed upon the scope of this report, i.e. >300MW and transmission connected, only the transmission connected contribution of the National Grid 2020 Future Energy Scenarios was considered.

Figure 48 displays these two scenarios (System Transformation in Green, Consumer Transformation in Blue) positioned within the collated trends (excluding the NIC Reformation scenarios), showing them to be in the lower end of forecasts for both Capacity and Generation. The predictions noted below should, therefore, be considered as conservative.

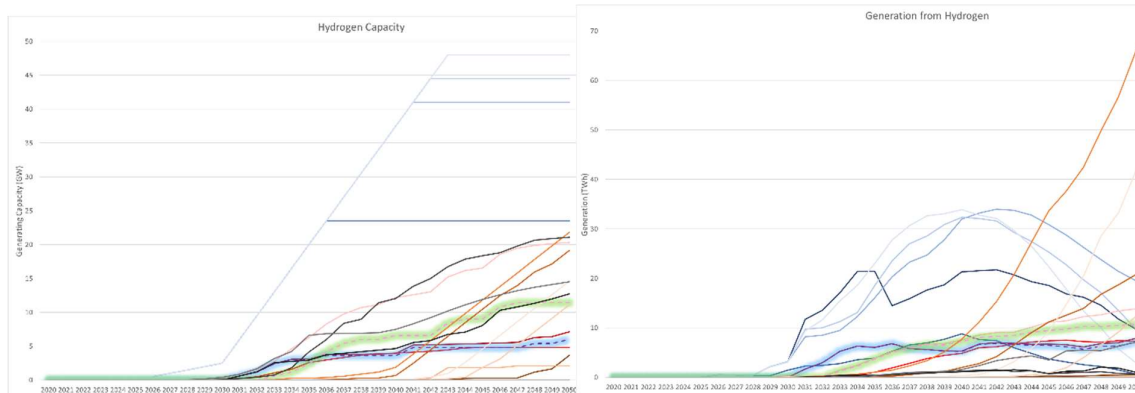


Figure 48 - Graphs to show NG FES 2020 Consumer and System Transformation trend highlighted amongst the collated trends

Two approaches were then applied to determine a regional contribution to the predicted capacity and generation;

- For the lower end, bearish estimate, the profiles were divided by 6 to represent an equal share of the capacity and generation being delivered by each of 6 industrial clusters across the UK.
- For the upper end, bullish estimate, the capacity/generation from H<sub>2</sub> turbines was scaled to be reflective of the % H<sub>2</sub> used for power in alignment with the relevant National grid predictions. This percentage was compared to the cluster as a whole using values forecast in Work Package 5.

Hydrogen demand required by the generation scenarios was calculated based on the Gas Turbine efficiencies as stated in Table 19. For the 2030 Bull scenarios, 53% efficiency was used in line with the assumptions applied to the CCC Sixth Carbon Budget scenarios. For all others, Gas Turbine efficiencies from the relevant National Grid FES Scenario were applied. These efficiencies were calculated from 2050 data and assumed to be constant throughout the considered timeframe.

Table 19 - Table to show potential capacity and generation volume of Hydrogen Turbines in the Cluster

Regional View	Big E				
	2030		2040		
	Bull	NG CT	Bull	NG CT Trans 1/6	
	Generatio TWh	1.05	0.00	2.40	0.87
Capacity GW	0.40	0.00	1.65	0.6	
Load Factor	30.00%		16.58%	16.58%	
Efficiency	53.00%	39.99%	39.99%	39.99%	
H2 pa TWhr	1.98	0.00	6.01	2.18	
Regional View	Big H				
	2030		2040		
	Bull	NG ST	Bull	NG ST Trans 1/6	
	Generatio TWh	0.88	0.00	2.07	1.21
Capacity GW	0.40	0.00	1.89	1.10	
Load Factor	25.00%		12.50%	12.50%	
Efficiency	53.00%	48.90%	48.90%	48.90%	
H2 pa TWhr	1.65	0.00	4.24	2.47	

Counterintuitively, where % Hydrogen for power is considered, the Big Electric scenario being proposed has a greater Hydrogen demand for power than the Big Hydrogen Scenario. This appears to be due to two factors; a comparatively higher total hydrogen demand in the Big Electric case compared to the Big Hydrogen proposed by WP5 (38% for WP5 outputs compared to 23% for NG scenarios (CT vs ST)), coupled with a lower GT efficiency for the National Grid Consumer Transformation scenario.

Table 20 -Table to show Hydrogen demands in the cluster as provided by WP5, including Hydrogen for power

TWh/a	2030				2040			
	Bull (Transition)		Bear (Transition)		Bull (Big H2)		Bear (Big Elec)	
Industrial Demand	20.45		12		24.9		16.8	
Residential Demand	2.4		0.9		31.1		0	
HGVs	0.45		0.1		1.25		0.45	
Rail	0.36		0.22		0.66		0.36	
Total H2 demand (w/o power)	23.66		13.22		57.91		17.61	
	NG CT	Bull	NG ST	Bull	NG ST (1/6)	NG ST (%)	NG CT (1/6)	NG CT (%)
Power	0	1.98	0	1.65	2.47	4.24	2.18	6.01
% power	0.00%	7.74%	0.00%	11.12%	4.08%	6.82%	11.02%	25.45%
Total H2 demand	23.66	25.64	13.22	14.87	60.38	62.15	19.79	23.62

1/6th of total %H2 for power 1/6th of total %H2 for power

Note, Hydrogen values above representative of LHV.

The LCOE values for these scenarios in 2030 are shown in Table 21.

Table 21: 2030 Big E and Big H Scenarios

	Big E		Big H	
	Predicted Load Factor	LCOE (£/MWh)	Predicted Load Factor	LCOE (£/MWh)
H <sub>2</sub> CCGT	30%	127.54	25%	135.26
H <sub>2</sub> OGCT	30%	144.21	25%	148.77

Specific LCOEs have not been calculated for 2040 as agreed forecasts for fuel costs, CO2 price etc were not available.

### 6.3.2.2 H<sub>2</sub> Generation Profile

Hydrogen demand modelling being developed in Work Package 5 required hourly demand data. As such, the annual generation volumes forecast for the north west, as detailed above, needed to be profiled across the year, reflective of electricity system supply and demand.

To do this, a simple dispatching tool was developed to simulate the dispatch of Hydrogen Turbines to provide flexible, peaking electricity supply, as is suggested by the NG Future Energy Scenarios.

A summary of the key assumptions feeding this tool can be seen below;

- Hydrogen Gas turbine capacity and generation was constrained at the values shown in Table 20
- 2019 electrical demand data plus embedded generation values is used as a basis (Sourced from National Grid (139)), uplifted to the specific FES scenario values (total annual demand) for the relevant scenario and year. This is done by addition of constant demand across the year rather than stretching the profile.
- A set 'firm load' value was chosen to run through the year reflective of FES scenarios
- Recurring daily storage was also incorporated reflective of FES scenarios
- The renewables profile from WP5 modelling has been upscaled to be reflective of FES scenarios
- Hydrogen Gas Turbines would be dispatched for a 4 hour minimum run
- The full UK Hydrogen Gas Turbine capacity is dispatched as a single unit and last on the 'merit order'
- No contribution is offered from interconnectors
- No other dispatchable technologies are considered/included

It should be noted that Hydrogen OCGTs and CCGTs could likely offer greater flexibility therefore shorter minimum run period than shown above, however, for the purpose of this model 4 hours was deemed to be representative of a possible averaged period.

The generation shortfall, i.e. difference between the demand and calculated supply (firm + storage + renewables) was then used to determine the dispatch of Hydrogen Turbines, with the tool taking incremental steps to calculate the point at which the defined Hydrogen Turbine capacity had produced the required generation volume.

Figure 49 shows the Hydrogen Turbine dispatch profile throughout the year, highlighting the intermittent operation of an asset delivering peaking power, constrained by the operational parameters identified by the model's assumptions.

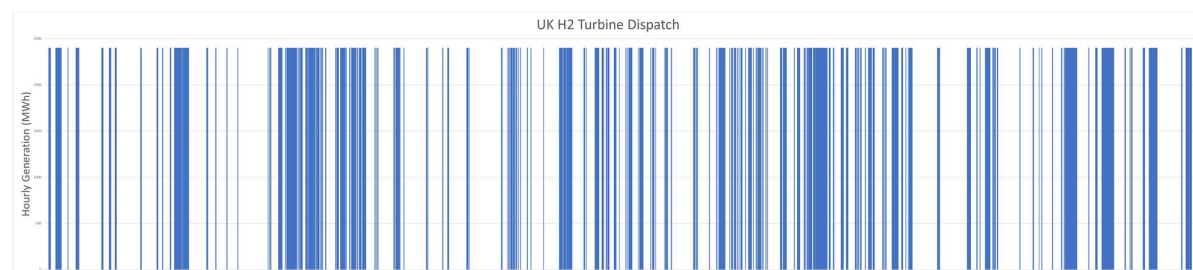


Figure 49 - Graph to show hourly dispatch of Hydrogen Turbines in 2030 for the Big Electric scenario

Due to the constraints placed upon this simplified model, the contribution of other flexible assets such as interconnectors, gas turbines and gas turbines with CCUS, have not been considered. These would likely play a significant role in providing flexible power onto the grid and as such a full system model considering individual assets, such as the BID3 model, would be needed to better understand specific dispatch profiles of each technology.

It is likely that where a more detailed model considered the effects of interconnectors and other flexible power generation, the dispatch profile would see a more significant season bias towards winter operation.

### 6.3.2.3 *H2 supply for power*

Due to the intermittent operation expected of Hydrogen Gas turbines, fuel supply must be equally flexible. Noting that the hydrogen supply rate for an NOAK 880 MW<sub>e</sub> H<sub>2</sub> CCGT is 458 kNm<sup>3</sup>/hr, this flexibility would need to be significant, providing both the required capacity and duration.

It is most likely that this would be achieved via the use of dedicated, flexible hydrogen production assets, shared, flexible hydrogen production assets or significant storage coupled with over-production from connected hydrogen production assets.

Detailed techno-economic modelling would be required to determine the most suited hydrogen supply methodology, considering the wider opportunities and constraints of the cluster, security of supply and overall system cost.

### 6.3.3. Natural Gas Turbines with Carbon Capture

As detailed in the previous sections, Natural Gas Turbines with CCS could provide a cost effective solution to delivering flexible or dispatchable power in a future energy scenario, with this likely being where there is a requirement for such assets to operate at higher load factors.

Operation of such assets would require flexibility in the carbon dioxide transport and storage infrastructure, potentially reducing its level of utilisation. This impact would need to be further explored with the CO<sub>2</sub> T&S provider.

It is uncertain, however, how the energy system will evolve, the specific technologies which we be deployed and therefore the extent to which these assets will develop in the NZNW region.

With there being no need for specific deployment forecasts to feed further modelling, specific capacity/generation figures for Gas Turbines with CCS in the NZNW region have not been proposed.

## 7. Summary

It has been shown that in order to reach Net Zero in the UK by 2050, significant changes must be implemented in the Electricity Sector. As is stated by each of the four Future Energy models consulted, much of this required decarbonisation is likely to be achieved via greater penetration of renewables, however, in order to maintain security of supply, low carbon dispatchable power is shown to be required throughout the forecast period to 2050.

Current technology forecasts suggest Hydrogen Turbines and Natural Gas Turbines with Carbon Capture to be the most likely technologies to provide a significant portion of the required low carbon dispatchable power. The exact mix, capacity and generation, however, is open to significant variation across future predictions.

Based on the proposals, made as part of HyNet and wider projects, for considerable hydrogen production, storage and infrastructure and CO<sub>2</sub> infrastructure and storage, there is significant opportunity for deployment of dispatchable low carbon power generation in the North West Region.

Some significant challenges must, however, be overcome before deployment of such assets can be considered as 'bankable' projects:

- Proof of technological capability at scale is required for both Hydrogen Gas Turbines and Natural Gas Turbines with CCS;
- Suitable business models and regulatory frameworks are required to ensure investor confidence; and
- Suitable and sufficient infrastructure developments, providing capacity and flexibility, will be required on Hydrogen, Carbon Dioxide and power networks.

## Table of Tables

TABLE 1 - LARGE SCALE DISPATCHABLE POWER GENERATORS IN THE NORTH WEST AND NORTH WALES REGION, REPRODUCED FROM (2).....	9
TABLE 2 - LARGE SCALE DISPATCHABLE POWER GENERATORS RECENTLY DECOMMISSIONED IN THE NORTH WEST AND NORTH WALES REGION, REPRODUCED FROM (2).....	9
TABLE 3: POTENTIAL DECARBONISED GENERATION TECHNOLOGIES CONSIDERED.....	10
TABLE 4: LOW CARBON DISPATCHABLE POWER TECHNOLOGIES.....	12
TABLE 5: COMMERCIAL PROCESS DEVELOPERS AND SOLVENTS.....	17
TABLE 6: TYPICAL CAPEX OF A 400 MW NG CCGT WITH CCS.....	24
TABLE 7: TYPICAL OPEX OF A 400 MW NG CCGT WITH CCS.....	24
TABLE 8: HYDROGEN CAPABILITY OF GE DLN, DLE, AND DIFFUSION COMBUSTION SYSTEMS.....	28
TABLE 9: SELECTED NG GTs WITH MAXIMUM EFFICIENCIES USED IN THE LCOE CALCULATION.....	37
TABLE 10: LARGE NG GT INDICATIVE START-UP TIMES BASED ON START TYPE AND TECHNOLOGY (DATA REPRODUCED FROM (85)).....	42
TABLE 11: FUEL PROPERTIES OF NATURAL GAS AND HYDROGEN.....	43
TABLE 12: HYDROGEN FUEL FLOW REQUIREMENTS FOR FOAK AND NOAK H <sub>2</sub> OCGT AND CCGT.....	43
TABLE 13: CAPEX FOR 400 MW <sub>e</sub> NG AND H <sub>2</sub> GT CONFIGURATIONS.....	45
TABLE 14: ANNUAL FIXED O&M FOR 400 MW <sub>e</sub> NG AND H <sub>2</sub> GT CONFIGURATIONS.....	46
TABLE 15: ANNUAL VARIABLE O&M FOR 400 MW <sub>e</sub> NG AND H <sub>2</sub> GT CONFIGURATIONS.....	47
TABLE 16: LCOE AT PREDICTED LOAD FACTORS.....	58
TABLE 17: COMPARISON OF 400 MW FOAK H <sub>2</sub> CCGT AND GAS CCGT+CCS PLANTS.....	60
TABLE 18 - LOW CARBON DISPATCHABLE POWER TECHNOLOGIES AS DEPLOYED IN THE VARIOUS FUTURE ENERGY SCENARIOS.....	69
TABLE 19 - TABLE TO SHOW POTENTIAL CAPACITY AND GENERATION VOLUME OF HYDROGEN TURBINES IN THE CLUSTER.....	78
TABLE 20 -TABLE TO SHOW HYDROGEN DEMANDS IN THE CLUSTER AS PROVIDED BY WP5, INCLUDING HYDROGEN FOR POWER.....	78
TABLE 21: 2030 BIG E AND BIG H SCENARIOS.....	78

## Table of Figures

FIGURE 1 - MAP OF MAJOR POWER PRODUCERS ACROSS THE REGION.....	9
FIGURE 2: PROCESS SCHEMATICS FOR CARBON CAPTURE OPTIONS .....	13
FIGURE 3: KEY COMPONENTS OF THE POST-COMBUSTION CAPTURE PROCESS .....	14
FIGURE 4: NET-ZERO HYDROGEN GAS TURBINES USING “GREEN” H <sub>2</sub> (TOP) OR “BLUE” H <sub>2</sub> (BOTTOM).....	25
FIGURE 5: TIMELINE OF SELECTED GE HYDROGEN GAS TURBINE PROJECTS (REPRODUCED FROM (36)) .....	27
FIGURE 6: GE HYDROGEN CAPABILITY (%VOL) BY GT CLASS (REPRODUCED FROM (41)).....	28
FIGURE 7: MAP OF SELECTED SIEMENS ENERGY HYDROGEN GAS TURBINE PROJECTS (REPRODUCED FROM (44)).....	29
FIGURE 8: SIEMENS ENERGY HYDROGEN CAPABILITY (%VOL IN NG) BY GT POWER OUTPUT AND COMBUSTION SYSTEM (REPRODUCED FROM (45)).....	30
FIGURE 9: TIMELINE AND H <sub>2</sub> CONTENT OF SELECTED MITSUBISHI HYDROGEN GAS TURBINE PROJECTS (REPRODUCED FROM (48)) .....	30
FIGURE 10: MITSUBISHI HYDROGEN CAPABILITY (%VOL) BY GT POWER OUTPUT AND COMBUSTION SYSTEM (REPRODUCED FROM (50)) .....	31
FIGURE 11: ANSALDO ENERGIA HYDROGEN CAPABILITY (%VOL) BY GT AND COMBUSTION SYSTEM (REPRODUCED FROM (51)).....	32
FIGURE 12: UK HYDROGEN GAS TURBINE PROJECTS, FEASIBILITY STUDIES, AND ANNOUNCEMENTS.....	33
FIGURE 13: THE IMPACT OF HYDROGEN BLENDING ON CO <sub>2</sub> EMISSIONS FOR A GE 9HA.02 CCGT (REPRODUCED FROM (36)).....	37
FIGURE 14: FLAME TEMPERATURE OF H <sub>2</sub> -AIR AND CH <sub>4</sub> -AIR MIXTURES AT 15°C AND 1 BAR.....	38
FIGURE 15: THE IMPACT OF H <sub>2</sub> ADDITION TO NG ON NO <sub>x</sub> EMISSIONS IN A GE GAS TURBINE (DATA REPRODUCED FROM (36)).....	39
FIGURE 16: THE IMPACT OF H <sub>2</sub> ADDITION TO NG ON NO <sub>x</sub> EMISSIONS IN AN ANSALDO ENERGIA AE94.3A COMBUSTOR TEST (REPRODUCED FROM (81)).....	39
FIGURE 17: GHG EMISSIONS INTENSITY (KG CO <sub>2,eq</sub> / KG H <sub>2,LHV</sub> ) OF VARIOUS H <sub>2</sub> PRODUCTION METHODS IN 2030 AND 2050 (REPRODUCED FROM (83)) .....	40
FIGURE 18: LCOE BASE CASES SUMMARY.....	49
FIGURE 19: TODAY BASE CASE LCOE .....	50
FIGURE 20: 2030 LCOE BASE CASE FOR 15% LOAD FACTOR.....	51
FIGURE 21: 2030 LCOE BASE CASE FOR 85% LOAD FACTOR.....	52
FIGURE 22: 2035 BASE CASE FOR 15% LOAD FACTOR.....	53
FIGURE 23: 2035 BASE CASE FOR 85% LOAD FACTOR.....	53
FIGURE 24: REDUCTION IN LCOE BETWEEN FOAK AND NOAK CASES AT 15% LOAD FACTOR.....	54
FIGURE 25: REDUCTION IN LCOE BETWEEN FOAK AND NOAK CASES AT 85% LOAD FACTOR.....	54
FIGURE 26: 2035 LCOE FOR H-CLASS CCGT AT 15% LOAD FACTOR.....	55
FIGURE 27: 2035 LCOE FOR H-CLASS CCGT AT 85% LOAD FACTOR.....	55
FIGURE 28: 2035 LCOE COMPARISON OF CCGT TYPES .....	56
FIGURE 29: CO <sub>2</sub> AVOIDANCE COST.....	56
FIGURE 30: PLANT LOAD FACTOR SENSITIVITY (2030).....	57
FIGURE 31: PLANT LOAD FACTOR SENSITIVITY (2035).....	57
FIGURE 32: BREAK EVEN CO <sub>2</sub> PRICE .....	58
FIGURE 33: BREAK-EVEN HYDROGEN PRICE AGAINST UNABATED NATURAL GAS .....	59
FIGURE 34: BREAK-EVEN HYDROGEN PRICE AGAINST GAS CCS.....	59
FIGURE 35 - A HOLISTIC VIEW OF THE COSTS AND REVENUES ASSOCIATED WITH A POWER CCUS PLANT AND THEIR STRUCTURE OF PAYMENT, REPRODUCED FROM FIGURE 6 IN (131).....	66
FIGURE 36 - TOTAL UK ELECTRICITY CONSUMPTION INCLUDING USE OF ‘SURPLUS’ GENERATION FOR ELECTROLYSIS. GRAPH REPRODUCED FROM THE CCC SIXTH CARBON BUDGET DATASET (21),.....	67
FIGURE 37 - GRAPHS FROM THE 2020 AND 2021 NATIONAL GRID FUTURE ENERGY SCENARIOS (6) (138), SHOWING THE VARIATION IN PREDICTED INSTALLED GENERATING CAPACITY AND PEAK DEMAND .....	68
FIGURE 38 - GRAPH TO SHOW COMPILED GENERATING CAPACITY FOR HYDROGEN GAS TURBINES IN THE UK ACROSS ALL MAPPED SCENARIOS .....	71
FIGURE 39 - GRAPH TO SHOW COMPILED ELECTRICITY GENERATION FROM HYDROGEN TURBINES IN THE UK ACROSS ALL MAPPED SCENARIOS .....	71
FIGURE 40 - GRAPH TO SHOW COMPILED LOAD FACTORS OF HYDROGEN TURBINES FOR THE UK ACROSS ALL MAPPED SCENARIOS .....	72

FIGURE 41 - GRAPH TO SHOW COMPILED GENERATING CAPACITY FOR NATURAL GAS TURBINE WITH CCS IN THE UK  
ACROSS ALL MAPPED SCENARIOS ..... 73

FIGURE 42 - GRAPH TO SHOW COMPILED ELECTRICITY GENERATION FROM NATURAL GAS TURBINES WITH CCS IN THE  
UK ACROSS ALL MAPPED SCENARIOS ..... 73

FIGURE 43 - GRAPH TO SHOW COMPILED LOAD FACTORS OF NATURAL GAS TURBINES WITH CCS IN THE UK ACROSS ALL  
MAPPED SCENARIOS ..... 74

FIGURE 44- GRAPH TO SHOW COMPILED GENERATING CAPACITY FOR NATURAL GAS TURBINE WITH CCS AND  
HYDROGEN GAS TURBINES IN THE UK ACROSS ALL MAPPED SCENARIOS ..... 74

FIGURE 45- GRAPH TO SHOW COMPILED ELECTRICITY GENERATION FROM NATURAL GAS TURBINES WITH CCS AND  
HYDROGEN TURBINES IN THE UK ACROSS ALL MAPPED SCENARIOS ..... 75

FIGURE 46- GRAPH TO SHOW COMPILED LOAD FACTORS OF NATURAL GAS TURBINES WITH CCS AND HYDROGEN  
TURBINES IN THE UK ACROSS ALL MAPPED SCENARIOS ..... 75

FIGURE 47 - MAP TO SHOW POSSIBLE LOCATIONS OF FUTURE LOW CARBON DISPATCHABLE POWER ASSETS..... 76

FIGURE 48 - GRAPHS TO SHOW NG FES 2020 CONSUMER AND SYSTEM TRANSFORMATION TREND HIGHLIGHTED  
AMONGST THE COLLATED TRENDS ..... 77

FIGURE 49 - GRAPH TO SHOW HOURLY DISPATCH OF HYDROGEN TURBINES IN 2030 FOR THE BIG ELECTRIC SCENARIO79

## References

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