Decarbonisation Readiness - Technical Studies

Hydrogen Readiness

Department for Business, Energy and Industrial Strategy

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Delivering a better world

Quality information

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Executive Summary

Since 2009, new build combustion power plants sized over 300MWe in England and Wales have been required to demonstrate they could retrofit carbon capture and storage (CCS) in order to decarbonise. This policy has been known as 'Carbon Capture Readiness' (CCR).

In 2009, detailed guidance was produced to support industry and BEIS in assessing the CCR requirements. Due to evolution of gas turbine size and efficiency, variable load profiles for fossil fuel plants, and to recognise the changing landscape of carbon capture and decarbonisation technologies, this guidance needs to be updated, as plants below 300MWe and new plant types (e.g. combined heat and power, energy from waste and biomass) will now be assessed for carbon capture readiness. The guidance document will also be expanded to cover hydrogen readiness as a means of decarbonisation.

As part of the expansion, BEIS are renaming the policy to 'Decarbonisation Readiness'. In order to update the guidance BEIS have commissioned two technical studies to update and expand the underpinning evidence base that was used to develop the guidance documents.

The technical studies are:

- Lot 1 – Hydrogen readiness
- Lot 2 – Carbon capture readiness

This document reports the findings of the **'Lot 1 - Hydrogen readiness' technical study'.**

Objectives

The aim of this project is to develop an evidence base that is used to define the requirements for demonstrating decarbonisation via hydrogen readiness and inform guidance. This was to be developed by addressing the following five objectives as part of this study:

- **Objective 1:** identify the equipment which a hydrogen combustion plant will require that differs from a typical combustion plant, and the spatial footprint associated with each piece of equipment.
- **Objective 2:** produce a checklist of the technical changes required to convert a plant to hydrogen combustion.
- **Objective 3:** research the alternatives to pipeline hydrogen fuel access e.g. on-site production, on-site storage, transport by road etc. and to determine their potential for the future.
- **Objective 4:** make estimates of the additional capital costs (including opportunity costs - e.g. outages whilst retrofitting) and the additional operational costs (e.g. plant machinery, increased costs of leakage monitoring, NOx abatement equipment, increased safety requirements) of converting a plant to hydrogen firing.
- **Objective 5:** estimate the dates by which combustion technologies that can fire increasing blends of hydrogen (e.g. 20%, 50%, 100%) will be available from manufacturers.

Approach

The approach for the final report comprises the expansion of the interim report to include the qualitative analysis of evidence that should be considered for generating of the evidence base for Decarbonisation Readiness Requirements. This includes the Literature Review undertaken to address the study Objectives as well as record of ongoing dialogue with stakeholders and introduction of the case studies to be assessed.

Conclusions and Recommendations

Key differences between hydrogen and natural gas

The key differences between hydrogen and natural gas have been compared in this study to demonstrate the challenges of switching to hydrogen for power generation. These comprise key differences regarding the technical performance, regulatory changes and changes to process safety following a future switch to hydrogen fuel.

Objective 1

Footprints for the main equipment items associated with hydrogen conversion for power generation have been calculated, as well as the impact on overall footprint for each case study in relation to a future fuel switch to hydrogen.

Objective 2

A new hydrogen-specific checklist has been developed to meet the needs of power generators sourcing hydrogen from an external hydrogen hub or through on-site production and/or buffer storage. The review has also highlighted the gap where examination of the feasibility for future fuel switching may need to be undertaken on the evidence available for partial blending. In these cases, an understanding will be required of the full composition of the fuel as this will have an impact on its performance, carbon intensity, and therefore relevance to predicting the feasibility of future conversion to full hydrogen firing.

Objective 3

This review has examined the hydrogen supply chain in relation to the supply of hydrogen to sites that may not have a reliable pipeline supply and therefore wish to deploy on-site storage with either batch delivery of hydrogen to site or on-site production. The potential role for on-site manufacture of hydrogen for power generation seems more applicable to smaller-scale peaking plant where a lower capacity factor can be used to offset periods of consumption with relatively steady periods of hydrogen generation, fed by low-carbon energy sources as defined by the Low Carbon Hydrogen Standard. Satisfying the needs of hydrogen production for large plant that may be required to run for extended periods of time seems more suited to offsite centralised means for production and storage such as seasonal underground caverns.

The challenges associated with provision of on-site hydrogen storage have been explored, particularly where the storage is used to support long durations of full-load operation. The challenges of bringing hydrogen to sites without pipeline access have also been summarised.

Objective 4

Both capital and operating costs have been calculated for each case study assuming the retrofit conversion of natural gas firing systems to hydrogen-firing systems as conservative First-Of-A-Kind costs. The estimated costs range from approximately £20,000 to £1,170,000 per MWth net heat input, with the higher end of the range generally associated with the smallest case studies such as arrays of reciprocating engines. Overall cost reduction of up to 50% for Nth-Of-A-Kind plant may be feasible through supply chain efficiencies as well as standardisation of associated activities such as engineering, permitting and project development.

The additional operating costs within this review have been limited to variable fuel and SCR reagent cost differences in relation to natural gas and calculated as approximately £91-92 per MWh of net heat input. Approximately 90-95% of the variable operating cost figure was associated with the incremental cost of hydrogen compared to natural gas, highlighting the importance of the cost of hydrogen supply for projects considering hydrogen firing.

Objective 5

The major manufacturers of power generation equipment have announced development programmes to enable conversion of their fleets to enable hydrogen-firing by 2030. This review has summarised the information available in relation to currently supported levels of hydrogen blending, as well as the barriers to increasing hydrogen blends and the various development programmes for increasing future blend ratios towards full blending

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1. Introduction

1.1 Project Outline

Since 2009, new build combustion power plants sized 300MWe and over in England and Wales have been required to demonstrate they could retrofit carbon capture and storage (CCS) in order to decarbonise. This policy has been known as 'Carbon Capture Readiness' (CCR).

In 2009, detailed guidance was produced to support industry and BEIS in assessing the CCR requirements. Due to evolution of gas turbine size and efficiency, variable load profiles for fossil fuel plants, and to recognise the changing landscape of carbon capture and decarbonisation technologies, this guidance needs to be updated, as plants below 300MWe and new plant types (e.g. combined heat and power, energy from waste) will now be assessed for carbon capture readiness. The guidance document will also be expanded to cover hydrogen readiness as a means of decarbonisation.

As part of the expansion, BEIS are renaming the policy to 'Decarbonisation Readiness'. In order to update the guidance BEIS have commissioned two technical studies to update and expand the underpinning evidence base to support the guidance document updates.

The technical studies are:

- Lot 1 – Hydrogen readiness
- Lot 2 – Carbon capture readiness

This document reports the findings of the **'Lot 1 - Hydrogen readiness'** technical study.

1.2 Project Aim

BEIS require that hydrogen readiness is demonstrated through the five different assessments as summarised below:

1. that sufficient space is available on or near the site to accommodate any equipment necessary to facilitate hydrogen conversion;
2. that it will be technically feasible to convert the site to 100% hydrogen-firing;
3. that the site's location enables the transport of hydrogen to the site and/or that hydrogen can be produced and potentially stored at the site;
4. that it is likely to be economically feasible, within the power station's lifetime, to convert to hydrogen combustion; and
5. that the plant will be technically capable of firing a blend of hydrogen on the day it is put into operation.

1.3 Objectives

The aim of this project is to develop the evidence base used to define the requirements for demonstrating decarbonisation readiness and inform guidance. This was to be developed by addressing the following five objectives as part of this study:

- **Objective 1:** identify the equipment which a hydrogen combustion plant will require that differs from a typical combustion plant, and the spatial footprint associated with each piece of equipment.
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- **Objective 5:** estimate the dates by which combustion technologies that can fire increasing blends of hydrogen (e.g. 20%, 50%, 100%) will be available from manufacturers.

2. Technical Approach

2.1 General approach

The following section details the methodology that AECOM utilised to complete the scope of work.

Independent Reviewers from academia were appointed to conduct an independent senior review of the technical delivery approach, deliverables and supporting technical work to validate that the outputs meet the scope objectives and that appropriate data and methods have been used.

Figure 1 illustrates the approach at a high level, including the timing of key meetings and independent reviewer activities.

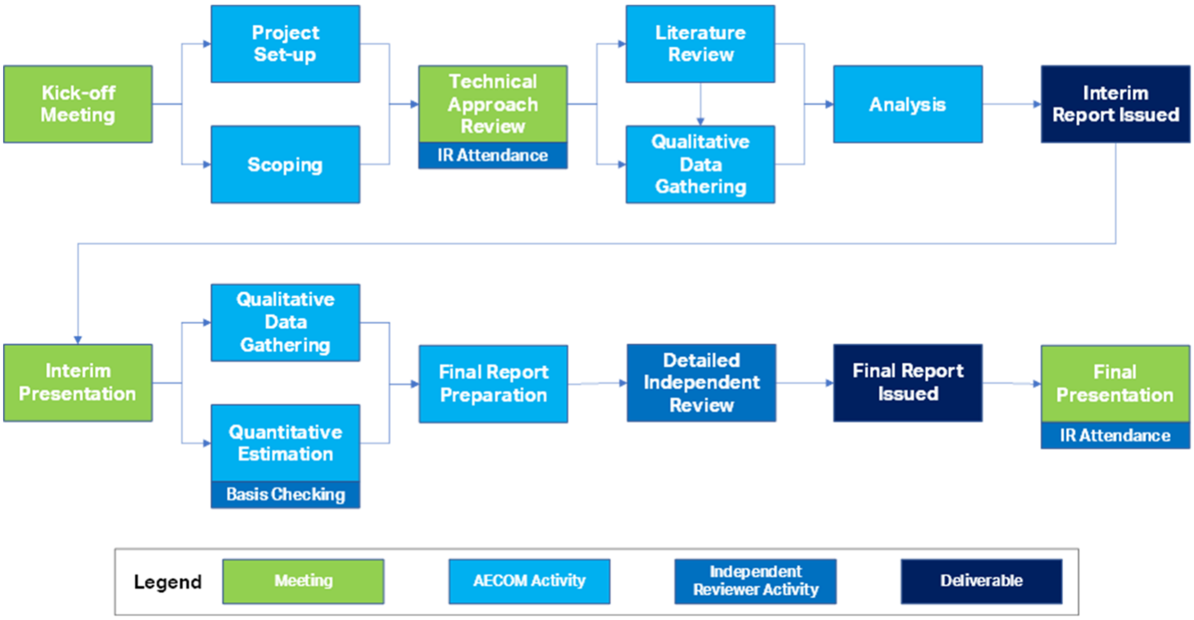

Figure 1. Outline of study approach

2.2 Scoping

The purpose of the scoping exercise was to identify sources of information that may contribute to the evidence base for this study, and include (but not limited to):

- Academic papers, journals and conference presentations;
- Documents for global industry bodies and organisations such as the IEA;
- Vendor publications, technical papers and experience lists;
- Publicly available planning applications; and
- Public domain feasibility and FEED studies.

A full list of the source documents assessed are provided in Appendix A of this report.

2.2.1 Review of existing guidance

To address Objective 2, an initial assessment of the 2009 CCR guidance document checklist was completed prior to the Technical Approach Review meeting. The checklist items were converted into a spreadsheet with each item being reviewed and categorised, with updates and areas where additional evidence was required identified. A workshop with the key stakeholders BEIS, the Welsh Government, the Environment Agency (EA) and Natural Resources Wales (NRW) was also organised to not only identify changes to existing checklists but expand to capture the challenges specific to hydrogen combustion.

The purpose of this exercise was to structure the following phases of the study and search for evidence.

The record of the checklist review is provided in Appendix B.

2.3 Qualitative Assessment

2.3.1 Literature Review

A literature review was completed of the sources identified in the scoping exercise, to extract relevant information to expand and update the existing evidence base.

In completing the literature review, the following examples are some of the types of evidence that were sought, and in parenthesis are the objectives they look to address:

- State of the art hydrogen combustion and on-site production facilities that are in operation or near commercial deployment (Objectives 1 - 5);
- Case studies of existing operating facilities and demonstration plants (Obj. 1-5);
- Land footprint of hydrogen combustion and on-site production facilities in operation or in planning phase where significant engineering has been completed (Objective 3);
- Academic papers on performance of hydrogen fired turbines and engines (Obj. 2);
- Vendor information regarding performance and operation (2, 3 & 5).

The findings of the literature review are summarised in Section 3 and a list of reference documents provided in Appendix A.

2.3.2 Stakeholder Engagement

Delivery of the project is supported and informed by engagement with different groups of stakeholders. At project inception AECOM generated a Stakeholder Engagement Plan, the purpose of which was to define the different groups, the objectives, methods and timings of engagement.

A copy of the Stakeholder Engagement Plan (60677821-TN-001) is provided in Appendix C of this report.

A complete list of the stakeholders engaged is summarised in Appendix A, Section 0.

2.4 Quantitative Estimation

To address Objective 1 and 4 it was necessary to develop a concept level design using a number of representative configurations as case studies. These were used to produce footprint estimates as well as capital and operating cost estimates for onsite assets with a clear and consistent defined basis.

The case studies provide an evidence base that can be used by examiners during the application process to determine if the acceptance criteria for assessments 1 and 4 defined in Section 1.2 have been addressed appropriately by developers.

2.4.1 Case Studies

These case studies focus on the fuel switching from natural gas to hydrogen on a range of different configurations and sizes of power plants. The selection of the case studies was discussed with key stakeholders and independent peer reviewers as part of the Technical Approach Review meeting. These discussions and rationale are captured in the ‘Rationale for case study scenarios’ Technical Note (60677821-TN-002) provided in Appendix C of this report.

The case study configurations defined in Table 1 cover a broad range of hydrogen demands and technologies. AECOM have provided the CO_2 avoided, fuel energy demand and hydrogen demand for each configuration to allow for interpolation of plants of different sizes.

Table 1. Case Study Definition

Combustion Technology	Sizing Basis	Small	Medium	Large
CCGT (Utility Scale)	Plant nominal gross power output	220 MWe	450 MWe	805 MWe
OCGT (Utility Scale)	Plant nominal gross power output	2 MWe	4 MWe	290 MWe
CCGT (CHP application)	GT nominal gross power output	14 MWe	35 MWe	60 MWe
Boiler (CHP)	Boiler Output	10 MWth	65 MWth	150 MWth
Reciprocating Engine	Engine nominal gross power output	1 MWe	12.5 MWe (5 x 2.4 MWe units)	50 MWe (5 x 10 MWe units)

2.4.2 Concept Design Basis

To support the development of the case studies and to provide transparency of the assumptions made, AECOM produced an engineering basis document (60677821-TN-003), which is provided in Appendix C of this report.

2.4.3 Basis for Economic Analysis

To support the development of the case studies and to provide transparency of the assumptions made, AECOM produced a Basis for Economic Analysis document (60677821-TN-005), which is provided in Appendix C of this report.

2.4.4 Basis for Layout Development

To support the development of the case studies and to provide transparency of the assumptions made, AECOM produced a Basis for Layout Development document (60677821-TN-006), which is provided in Appendix C of this report.

2.5 Summary Report

The outputs of the study are summarised in a single report (this document), that is subject to an independent review by both the independent peer reviewers and stakeholders within BEIS, the Welsh Government, the Environment Agency (EA) and Natural Resources Wales (NRW).

3. Analysis

The analysis section presents the outcomes of the Qualitative and the Quantitative aspects of the study to address the Objectives stated in Section 1.

3.1 Hydrogen as a means of decarbonisation

Hydrogen as a fuel, has the potential to decarbonise combustion processes that currently utilise natural gas. The degree of decarbonisation achievable is dependent upon:

1. the extent to which hydrogen displaces carbon containing elements in the feedstock, and
2. the carbon intensity of the hydrogen production process.

Figure 2 illustrates the relationship between the amount of hydrogen in the fuel (by volume) and the reduction in CO_2 produced. This relationship is not linear as the calorific value of methane per unit volume is over three times that of hydrogen and is illustrated in Figure 3.

For example, blending hydrogen into natural gas at levels of 20% by volume will only result in a 7.4% reduction in CO_2 generated compared to 100% methane.

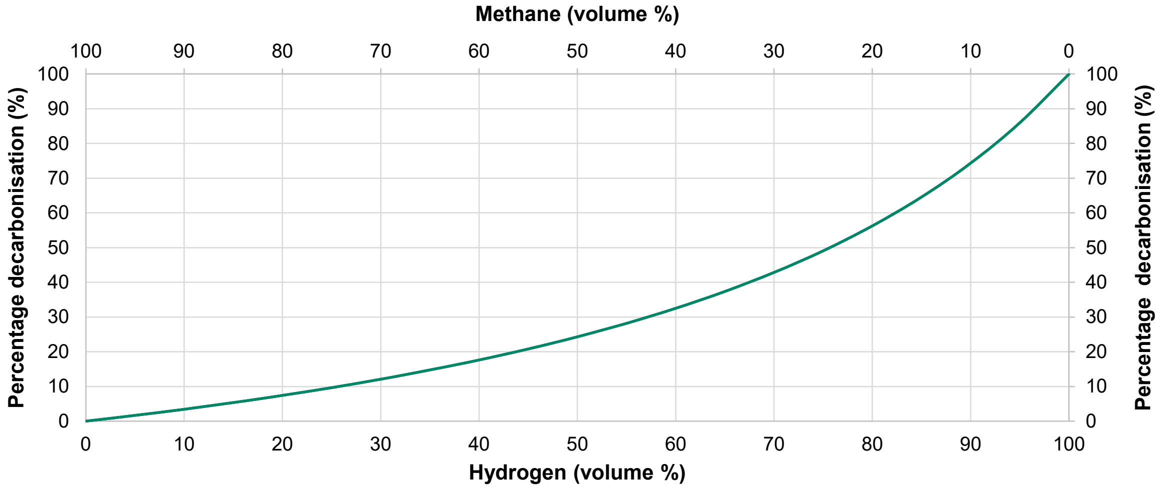

Figure 2. Relationship between CO_2 emissions and hydrogen/methane fuel blends (vol%)

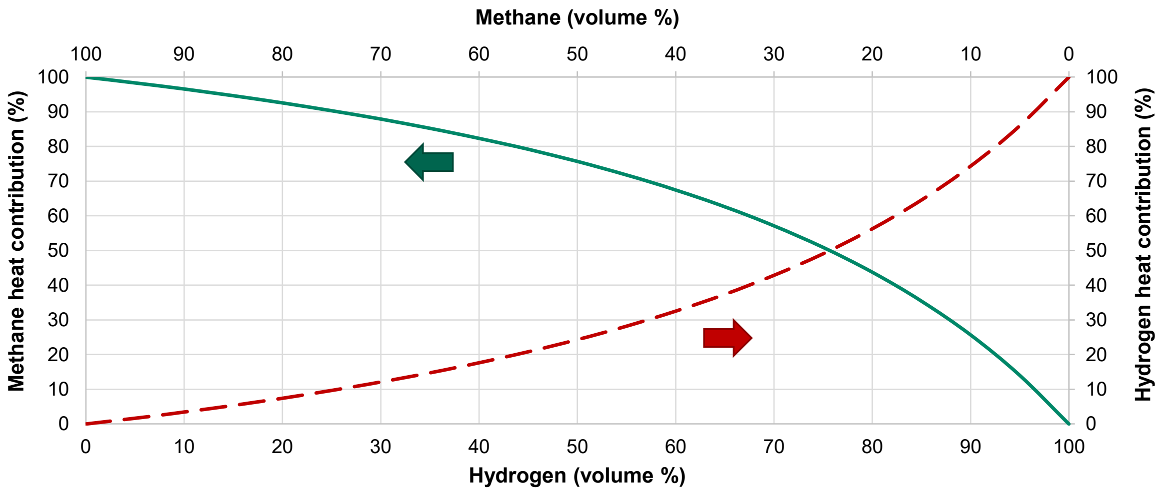

Figure 3. Relationship between heat input contribution and methane-hydrogen blending

Figure 2 represents the CO2 emissions at the point of combustion. The carbon intensity of the hydrogen production process depends on the technology selected and whether the production process utilises renewable power, which is discussed further in Section 3.5.

While the carbon generation through the entire value chain is key in terms of achieving the objectives of decarbonisation of the power industry, the focus of this report is on the combustion of hydrogen as a fuel and the technical and economic barriers associated with this.

The low carbon credentials of the hydrogen suppliers are being investigated through the UK Low Carbon Hydrogen Standard[1] project, which is being delivered by BEIS (consultation for which was completed in October 2021 and the draft Standard has been released in April 2022) and is outside the scope of this report.

3.2 Key differences between Hydrogen and Methane

The 2009 Carbon Capture Readiness document catered for coal and gas fired power generation facilities. However, since then almost all the UK's existing coal plants have closed, and it is unlikely that there will be any future new-build coal plants.

To better appreciate the implications of decarbonising the power industry with hydrogen, the following section discusses the key differences between hydrogen and methane as a fuel and implications that has on combustion equipment and power generation facilities.

Table 2 summarises the key properties of Hydrogen, Methane and Propane.

Table 2. Properties of Hydrogen, Methane and Propane[2,3]

Parameter	Unit	Hydrogen	Methane	Propane
Molecular weight	g/mol	2.016	16.040	44.097
Density at NTP	kg/m³	0.08	0.65	1.87
Self-ignition temperature[a]	K	845 - 858	813 - 905	760 - 766
Minimum ignition energy	mJ	0.02	0.29	0.26
Flammability range in air	vol%	4 - 75	5 - 15	2.1 - 10
Adiabatic flame temperature (at constant equivalence ratio and pressure)	K	2318 - 2400	2158 - 2226	2198 - 2267
Burning velocity	cm/s	237	42	46
Laminar flame speed (max)	cm/s	325	45	38
Lower heating value (mass)	MJ/kg	120.0	50.0	46.4
Higher heating value (mass)	MJ/kg	141.8	55.5	50.4
Lower heating value (vol.)	MJ/Sm³	10.8	35.8	91.21
Higher heating value (vol.)	MJ/Sm³	12.8	39.7	99.03
Wobbe index (LHV basis)	MJ/Sm³	40.7	47.9	73.3

3.2.1 Combustion Characteristics

3.2.1.1 Heat of Combustion

The lower heating value (LHV) of hydrogen at 10.8 MJ/Sm³ is less than a third of that of methane at 35.8 MJ/Sm³. This lower energy density means that, for a given duty, the volumetric flow of hydrogen would be over three times that of methane.

This may result in constraints within the fuel distribution network or the combustion equipment, causing a restriction in flow and de-rating of the plant capacity if pipework is sized for natural gas only and is not replaced.

[1] BEIS, 2021, Designing a UK Low Carbon Hydrogen Standard, https://www.gov.uk/government/publications/uk-low-carbon-hydrogen-standard-emissions-reporting-and-sustainability-criteria, accessed 04 May 2022.
[2] Du Toit M.H., Avdeenkov A.V., Bessarabov D.; Reviewing H2 Combustion: A Case Study for Non-Fuel-Cell Power Systems and Safety in Passive Autocatalytic Recombiners, Energy Fuels 2018, 32, 6401−6422
[3] Botha J.P. and Spalding D. B., 1954, *The laminar flame speed of propane/air mixtures with heat extraction from the flame*, Available from: https://doi.org/10.1098/rspa.1954.0188

Figure 4 illustrates the relative difference in line size for natural gas and hydrogen utilising the same line sizing criteria. At the conditions presented, the line size required for hydrogen is typically one to two line sizes greater than that required to supply the equivalent energy flow with natural gas.

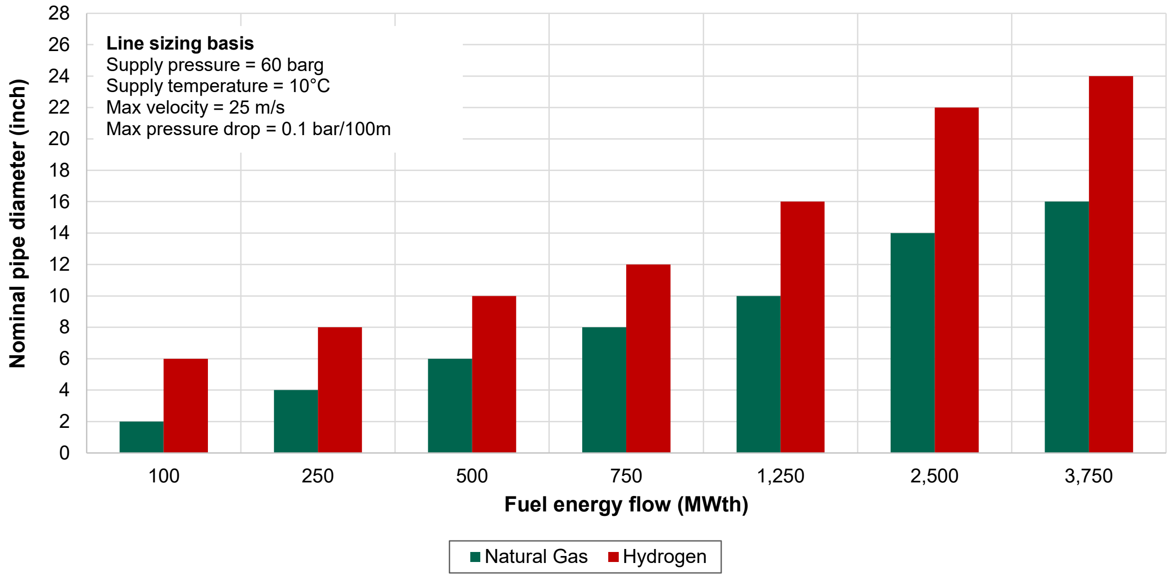

Figure 4. Relative pipe size required for natural gas and hydrogen

It is worth noting that the criteria utilised to produce this figure are for illustration purposes applying criteria typically used for reasonable design of on-site piping systems to provide a balance between pressure drop and cost. For retrofit application on existing sites an assessment can be made on a site-specific basis where there might be strong incentive to retain existing line sizes wherever feasible. Features such as large radius bends to enable higher velocities, or specific assessment whether the pressure drop rules can be relaxed for individual users that may be capable of satisfactory operation with reduced pressure can be evaluated. To a lesser extent, the decision to adopt smaller lines may also be made during value engineering studies in latter stages of engineering development.

The impact of gas supply pressure is also likely to have different impacts on the final decision whether to retain or replace piping. The key factors are summarised in Table 3, separated between higher pressure piping and lower pressure piping. The level of pressure has not been defined in either case because the ultimate decision would be site-specific and potentially iterative.

Table 3. Key decisions in relation to replacement or keeping existing piping following switch to hydrogen

Test	Higher pressure gas supply	Lower pressure gas supply
Feasibility of meeting increased pressure drop from supply through on-site network to consumers for hydrogen	More likely to be accommodated within existing margin on pressure	Less likely to be accommodated due to low upstream pressure
Suitability of piping materials	Trends towards use of hydrogen compatible steel such as higher grades of carbon steel and therefore incompatibility for conveying high pressures of hydrogen	Materials more likely to be inherently compatible
Main drivers for replacing piping	Piping replacement tends to be for reasons of materials	Piping replacement tends towards reasons of capacity/pressure drop
Non-replacement options for resolving any capacity shortfall (applicable to both high and low pressure)	1.Raise pressure throughout piping (e.g. open upstream regulator). Consequence: extend hazardous areas around piping and instrumentation, may overlap equipment that was not previously in a classified hazardous area and may lead to requirement for upgrade (to	

Test	Higher pressure gas supply	Lower pressure gas supply
	meet new hazardous area classification) or relocation outside of hazardous area (if space is available). 2.Operate equipment with lower pressure (if some margin is available). Consequence: potential operability issues around hydraulics and continuing steady gas supply. Not generally a showstopper but still needs to be studied for specific equipment item to do with performance and flame stability controls.	
Additional works required before adopting either option	Assess new hazardous areas around piping, flanges and fittings, and equipment; implement actions from new hazardous area classification. Replacement of some fittings such as flanges may still be required for welded connections, which leads to maintenance challenges.	

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3.2.1.2 Wobbe Index

The Wobbe Index is used as a measure of operability of a selected fuel and is determined by the volumetric HHV and the densities of the fuel and air. Whilst methane and hydrogen have similar Wobbe index values they will provide the same heat output (providing the nozzle geometry and combustion pressure do not change) and, providing the index remains in the range 30 – 50 MJ/m^3, combustion systems designed for natural gas can be used with hydrogen without large scale modifications. The Wobbe Index is commonly used in the design of gas turbine systems, but it is not the only measure as the index does not account for variations in combustion properties such as burning velocities[2]. See Figure 5 for a plot of the variation of Wobbe Index with increasing hydrogen blend fractions and note the increase for the highest fractions of hydrogen which indicates that the Wobbe Index tends towards that of natural gas at very high fractions of hydrogen (41 MJ/m^3 at 90%, 45 MJ/m^3 at 100%)[4].

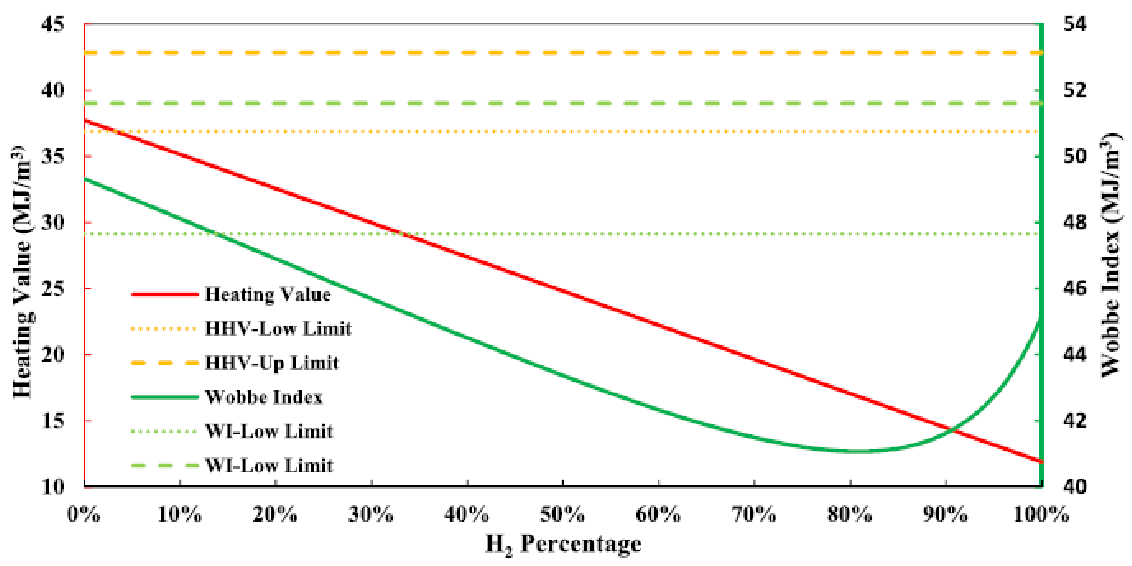


Figure 5. Heating value and Wobbe Index variation for blends of hydrogen and natural gas, by volume

3.2.1.3 Lewis Number

The Lewis number is an indicator of flame stability and the sensitivity of flames to disturbances. It is defined as the ratio of thermal diffusivity to the mass diffusivity of a fuel. Fuels with high Le values indicate more stable flames (with values above 1 generally expected to be stable, such as methane with Le = 1). The Le of hydrogen is approximately 0.45, which indicates a more unstable flame[5].

[4] Zhao Y. et al., Int J Hydrogen Energy 2019. https://doi.org/10.1016/j.ijhydene.2019.03.100
[5] Bouvet N. et al, Int J Hydrogen Energy 2013. doi:10.1016/j.ijhydene.2013.02.098.

3.2.1.4 Adiabatic Flame Temperature

The Adiabatic Flame Temperature is the equilibrium temperature of products when the reactants are notionally burned at a defined pressure without transferring heat to the environment. The adiabatic flame temperature for hydrogen is significantly higher than for methane. This results in more than three times the thermal NOx production and is an indicator of NOx emissions. This characteristic determines the maximum temperature of the combustor, and consequently the construction materials, and its efficiency. Therefore, an increased temperature can increase efficiency but may negatively impact burner equipment and hot gas path components due to overheating[2].

3.2.1.5 Hydrogen Burning Velocity

The burning velocity represents the rate of movement of chemical reactants into the reaction sheet from a local reference point that is located on the flame front i.e. the velocity at which the unburned gases propagate into the flame. The burning velocity affects the burning rate, position of flame front, flashback risk and flame stabilisation. The maximum burning velocity of hydrogen is approximately seven times faster than for methane, and this higher flame speed increases the risk of the flame burning closer to the injection points, travelling back into mixing passages or burning too close to liner walls, leading to damage. This risk increases as the hydrogen content in the fuel is increased and with increasing combustion inlet and flame temperature. This challenge is particularly significant for burner designs that utilise lean pre-mixing, pre-mixing or rapid pre-mix type techniques where minor changes in the quantity of hydrogen within the fuel may cause rapid changes to the overall fuel burning velocity.

As a result, combustion systems configured for methane (or natural gas) operation may be unsuitable and combustors designed specifically for the different combustion conditions of high hydrogen content fuels will need to be developed. Turbulent flame speed is considered more important than laminar flame speed, as the flame speed increases in the turbulent zone. With the increased flame speed, the combustion durations of hydrogen blends are reduced, and the flame is shortened. This has the potential to lead to shorter combustion chambers, reducing the combustion residence times, lowering the NO formation and cooling requirements.

3.2.1.6 Emissivity

A hydrogen flame has a lower emissivity than a methane flame as a result of the reduced concentration of radiant species such as soot, CO_2, and hydrocarbon radicals[6]. This also results in a hydrogen flame having a lower luminosity and requires ultraviolet flame detection rather than infrared flame detection typically used in natural gas applications.

3.2.1.7 Combustion Air Requirements

The stoichiometric combustion concentration of hydrogen in air (assuming air is made of 21% of oxygen and 79% of nitrogen) is 29.6 vol% with the air content of 70.4 vol% and is represented by the following chemical equation[7]:

$$2\,H_2 + (O_2 + 3.76\,N_2) \rightarrow 2\,H_2O + 3.76\,N_2 \qquad \Delta H = (-)\,572\text{ kJ}$$

This is different from methane, as each methane molecule needs two oxygen molecules to react fully as shown in the following equation:

$$CH_4 + 2\,(O_2 + 3.76\,N_2) \rightarrow CO_2 + 2\,H_2O + 7.52\,N_2 \qquad \Delta H = (-)\,890\text{ kJ}$$

From the perspective of oxygen demand, 22% less oxygen is required for the same energy release burning hydrogen compared to methane.

$$\text{Hydrogen combustion} = (-)\,572\text{ kJ} \div 1\text{ mol } O_2 = (-)\,572\text{ kJ/mol } O_2$$

$$\text{Methane combustion} = (-)\,890\text{ kJ} \div 2\text{ mol } O_2 = (-)\,445\text{ kJ/mol } O_2$$

$$\text{Relative Oxygen Demand} = (-)\,445\text{ kJ/mol } O_2 \div (-)\,572\text{ kJ/mol } O_2 = 78\%\text{ of methane}$$

Thus, the impact of converting to hydrogen does not negatively impact the combustion air requirement, and the fans suitable for natural gas firing should be capable of providing more combustion air than required by the equivalent hydrogen system.

[6] García-Armingol T et al. Int J Hydrogen Energy 2014;39:11299–307. doi:10.1016/j.ijhydene.2014.05.109.
[7] IGEM, 2021, Reference Standard for low pressure hydrogen utilisation, IGEM/H/1, UK.

3.2.1.8 Flammability

Hydrogen has a lower flammability limit and wider flammability range (in air) than methane, resulting in increased safety issues in the event of leaks or discharges. This will result in different procedures and safety / exclusion zones. Research has shown that there is a gap in the understanding of flammability limits (especially upper flammability limit), particularly under high hydrogen concentrations and elevated temperature[2].

3.2.2 NO_X performance

A summary of current typical NO_X performance across the different technologies when firing hydrogen is presented in Table 4. Note that this represents a conservative extrapolation across the different technologies, it is expected that individual sites would achieve lower values both for the current benchmark with natural gas, as well as future hydrogen fuel.

Table 4 NOx Input and Output Emissions, NO_X concentrations reported in ppmv dry, at 273.15K and 101.3kPa, and reference O_2 concentration

	Blend level (vol% H_2)	Gas turbines (ppmvd)	Boilers (ppmvd)	Reciprocating engines (ppmvd)
Baseline for NOx with natural gas	0%	100 – 500 ppmvd (Note 1)	BREF compliance	BREF compliance
Extrapolated estimate for NOx with hydrogen blends, with respect to natural gas benchmark, **uncontrolled** emissions	Up to 50vol%	Up to +30-40%		
	Up to 100% H_2	Up to +100% (Note 2)	100 – 200 ppmvd	200 – 500 ppmvd
Extrapolated estimate for NOx with 100% hydrogen and primary means of control	Up to 100% H_2	Target BREF by primary means	Up to 25 – 40ppmvd (Note 3)	200 – 250ppmvd (Note 4)
Secondary NOx abatement performance	N/A	90% reduction	90% reduction	90% reduction
Expected NOx levels with secondary abatement if required	N/A	BREF compliance	BREF compliance	BREF compliance

Note 1: The range of NO_X estimates presented is conservative and the upper end includes gas turbines using diffusion burners but operating without their primary control measures such as water injection. Gas turbine allowable emissions limits values are set within the relevant BREF documents.

Note 2: The estimate of incremental NO_{X+} for gas turbines is an extrapolated potential figure based on the natural gas benchmark range. This is a theoretical estimate rather than one supported by testing.

Note 3: Use of high excess air (and associated efficiency penalty) may be used to further lower NO_X in hydrogen boilers, possibly below 10ppmvd.

Note 4: reciprocating engines are expected to require some de-rating and/or additional excess air to avoid knocking as well as control NO_X to achieve the given estimate with primary means.

3.2.2.1 Pre-mixed Combustion

State-of-the-art pressurised combustion systems such as those that are deployed in gas turbine combustion applications generally operate through various types of pre-mixing. These systems allow control of the flame temperature and therefore one of the main contributing factors to NOx formation. Comparison of NO_X emissions across the various power generation technologies may require some application-specific approaches, however, maintaining a fixed flame temperature seems to be a reasonable approach which would not arbitrarily penalise fuel blends high in hydrogen.

3.2.2.2 Reporting Basis

NO_X emissions performance is frequently compared in terms of ppmv dry, normalised to a reference oxygen concentration, consistent with mg/Nm^3 dry and reference oxygen as used by environmental regulators. These approaches have been challenged in recent literature[8] due to the differences in concentration changes from drying and referencing the oxygen level. For example, a simulated gas

[8] Shaw S. L. et al., Proceedings of ASME Turbo Expo 2022, Pollutant Emissions Reporting and Performance Considerations for Hydrogen-Hydrocarbon Fuels in Gas Turbines, EPRI, June 2022

turbine with constant NO_X emissions mass per unit of useful work may be expected to indicate 39% higher NO_x production if ppmvd with reference oxygen were used, although this would be an artefact of the measurement technique rather than any real difference in terms of air quality impact.

3.2.3 Material Characteristics

3.2.3.1 Leak Potential

Due to its small molecule size, hydrogen has the potential to diffuse through seals that might be considered airtight or impermeable to other gases. Therefore, traditional sealing systems used with natural gas will potentially need to be replaced with alternative arrangements, e.g. welded connections. These sources of fugitive emissions are an issue that was addressed in a recent publication in April 2022 by BEIS[9].

Hydrogen diffusion through polyethylene materials (PE80) has been investigated and found to be five times higher than for natural gas but was still considered negligible (annual loss of 0.0005 – 0.001% of transported volume)[10]. However, the use of PE80 and PE100 is limited to ambient temperatures: neither are currently recommended globally for natural gas above 40°C and no global standard exists for hydrogen/natural gas mixtures at time of writing.

3.2.3.2 Embrittlement

Hydrogen can be absorbed by some materials which will result in embrittlement and the loss of ductility. This is caused by the interaction of hydrogen atoms with the crystal lattices of the material and is accelerated at elevated temperatures and pressures. Existing design codes provide guidance on appropriate materials for hydrogen systems depending on operating conditions, but it is recommended that materials such as lower strength carbon steels e.g. API 5 5L grades (X52 or lower), austenitic stainless steels or polyethylene (PE80 or PE100) are adopted for on-site piping systems[11].

3.2.4 Environment, Health and Safety Implications

3.2.4.1 COMAH

The COMAH Regulations apply to sites with significant inventories of dangerous substances and are intended to prevent major accidents and to limit the consequences to people and the environment of any accidents which do occur.

The additional requirements on site operators when classified as COMAH sites are not insignificant, and often drive developers in the specification of storage and design of their site in order to remove the obligations that would result from being classified as a COMAH site.

The threshold values for the applicability of COMAH requirements is defined in Table 5, and the threshold for hydrogen in mass terms is an order of magnitude lower than that of natural gas.

Table 5. COMAH thresholds for dangerous substances[12]

Substance (threshold units = tonnes)	Lower tier threshold	Higher tier threshold
Natural gas	50	200
LPG	50	200
Diesel	2,500	25,000
Hydrogen	5	50

However, it is important to consider the threshold in terms of energy stored and the energy density of hydrogen relative to natural gas. Table 6 describes the equivalent energy stored at the lower tier threshold for both natural gas and hydrogen, and it can be seen that in energy terms the lower tier threshold for natural gas is four times that of hydrogen.

[9] BEIS, 2021, Fugitive Hydrogen Emissions in a Future Hydrogen Economy, https://www.gov.uk/government/publications/fugitive-hydrogen-emissions-in-a-future-hydrogen-economy
[10] A. Brown, July 2020, Hydrogen: The future fuel today, Hydrogen Transport, IChemE
[11] A. Brown, July 2020, Hydrogen: The future fuel today, Hydrogen Transport, IChemE
[12] HSE, 2015, *The Control of Major Accident Hazards Regulations 2015*, 3rd Edition, HSE, UK.

Table 6. COMAH thresholds converted into energy terms

	Natural Gas	Hydrogen
Lower tier threshold (tonnes)	50	5
Lower heating value (MJ/kg)	50.0	118.8
Lower tier threshold, energy equivalent (GJ, LHV)	2,500	594

Table 7 has been provided to give context as to the inventory within a power plants fuel gas piping. The basis for the calculations is a power plant with a thermal input of 1,250 MWth. This is roughly equivalent to a combined cycle gas turbine power plant with two large F class gas turbines or one small H class gas turbine.

The fuel gas lines were sized utilising the same basis used in Section 3.2.1.1 to generate Figure 4. The conclusions of the calculation are that it is very unlikely that the lower tier threshold of COMAH will be exceeded for natural gas or hydrogen power plants with no on-site storage.

To exceed the lower threshold over 20km of pipe containing natural gas would be required and over 8 km of pipe containing hydrogen would be required. In power plants in the UK the layouts are typically compact and land usage is minimised and as result the fuel gas piping on plot is typically less than 250m in length and therefore unlikely to trigger a COMAH threshold in its own right.

Table 7. Evaluation of fuel gas piping inventory for power plant with thermal input of 1250MW$_{th}$

	Natural Gas	Hydrogen
Power plant thermal input (MW$_{th}$)	1250	1250
Pipeline supply pressure (barg)	60	60
Pipeline supply temperature (°C)	10	10
Required pipeline diameter (in, nominal)	10	16
Pipeline cross sectional area (m^2)	0.046	0.104
Gas density (kg/m^3 at pipeline pressure)	53.28	5.82
Gas inventory (kg per linear meter of fuel gas pipe)	2.47	0.60
Lower tier threshold (tonnes)	50	5
Fuel gas pipe length required to exceed threshold (m)	20,258	8,281

The COMAH thresholds are likely to only be relevant on sites where the production of hydrogen occurs alongside the power generation, where the operators view the security of supply of hydrogen to be lower than that of natural gas and elect to mitigate the risk of supply interruption by on site storage, or where there is no supply available at all.

In these instances, the switching of fuels from natural gas or diesel to hydrogen may result in increased numbers of power generators' sites being COMAH classified and will also likely influence the maximum deployed quantities of hydrogen stored on sites, which may not currently fall within the COMAH regulations. If conversion to hydrogen for such sites were to trigger COMAH (e.g. through local buffer storage for intermittent consumption), significant new regulatory requirements would be required to be overcome such as greatly enhanced, formal consultation requirements with the general population surrounding their site.

3.2.4.2 Dangerous Substances and Explosive Atmospheres Regulations

The Dangerous Substances and Explosive Atmospheres Regulations 2002 (DSEAR) require employers to control the risks to safety from fire, explosions and substances corrosive to metals. The Regulations implement two European Directives[13]:

– the safety aspects of the Chemical Agents Directive 98/24/EC (CAD); and

[13] HSE, 2013, *Dangerous substances and explosive atmospheres*, 2nd Edition, HSE, UK.

- the Explosive Atmospheres Directive 99/92/EC (ATEX) [14].

DSEAR require facility owners to carry out a hazardous area classification (HAC) exercise wherever there is a potential for flammable gas/air mixtures to form, be that due to leaks or deliberate venting. The HAC will identify and class areas into zones and minimum protection (ATEX) rating of electrical equipment within the respective zones.

Hydrogen will result in larger zones or necessitate a higher ventilation rate than would be required for natural gas due to the lower LFL and the higher volumetric leak rates that result from Hydrogen being a smaller molecule.

Hydrogen is easier to ignite than methane and is classified as a Group IIC gas, whereas methane/natural gas is considered less hazardous and classified as a Group IIA gas. Therefore, the equipment to be used within hazardous areas identified for hydrogen will need to be of a higher standard than currently required for NG installations.

For facilities converting from natural gas to hydrogen, the increase in hazardous zone sizes may lead to some overlap of existing equipment which would no longer be suitable for its classification and action would have to be taken by the site before converting to hydrogen. In these cases, a site-specific study would be required to consider the feasibility of options for:

- Relocating the equipment outside the hydrogen hazardous area, subject to availability of space to do so;
- Reduction of the zone size (e.g. through decreased gas pressure or improved **reliable** ventilation);
- Upgrade of the equipment to meet the new zone Classification (pending availability of equipment with suitable Classification)

For facilities expected to be hydrogen-enabled from the outset, an appropriate DSEAR assessment and HAC conducted by suitably qualified personnel should identify such hazardous areas and propose the appropriate safety measures.

3.2.4.3 Pressure Equipment (Safety) Regulations

The Pressure Equipment (Safety) Regulations (PESR) regulate the design, manufacture and conformity assessment of pressure equipment and assemblies with a maximum allowable pressure greater than 0.5 barg[15].

For most power generating facilities, the PESR apply widely and will not have any impact on the design or operation of the plant. However, for retrofitting of micro-generators and small plants where low gas pressures only are required, it may be desirable to increase the operating pressure to accommodate the lower energy density of Hydrogen to avoid de-rating of piping and equipment. Where the resulting pressure would exceed 0.5 barg then the equipment, assemblies and components within the system will need to be checked to ensure they comply with the requirements of the PESR and, if not, will require replacement.

3.2.4.4 Environmental Permitting

For new build sites and retrofitting to existing facilities, the principal environmental permitting implications of fully hydrogen-fired power generation, when compared to a similar natural gas application, are the potential for higher NOx generation and the resulting need to implement post-combustion emission controls such as Selective Catalytic Reduction (SCR).

For sites that include on-site production of hydrogen, water availability, effluent discharge and abstraction requirements are potential environmental concerns.

3.2.5 Summary

[14] HSE, 2014, ATEX and explosive atmospheres, https://www.hse.gov.uk/fireandexplosion/atex.htm
[15] Office for Product Safety and Standards, 2021, *Pressure Equipment (Safety) Regulations 2016 Guidance*, Ver. 3, BEIS, UK

Table 8. Summary of main differences between hydrogen and natural gas characteristics

Characteristic	Commentary
Heat of Combustion	• Less than a 1/3 of methane per unit volume • Volumetric flow > 3 times methane resulting in constraints in fuel distribution systems
Wobbe Index	• Measure of fuel interoperability - similar to methane • Blends with Wobbe values 30 – 50 MJ/m^3 can be used in combustion systems without large scale modifications
Flame stability	• Lewis Number less than half the value of methane leading to a more unstable flame
Adiabatic Flame Temperature	• Higher than methane • Results in 3 times the thermal NOx production (local at flame)
O_2 Demand	• Lower than methane
Flame Speed	• Greater than methane (max. is approx. 7 times) - affects burning rate • Position of flame front, flashback risk & flame stabilisation. Potential for increased risk of damage
Emissivity	• Lower than methane • Resulting in flames with lower luminosity requiring ultraviolet rather than infrared flame detection instrumentation
Flammability	• Lower flammability limit and wider flammability range than methane; requiring different procedures and expanding safety zones
Leak Potential	• Smaller molecule than methane, readily diffuses through common materials • Alternative sealing systems e.g. welded connections may be required

3.3 Objective 1 – Footprint

***Objective 1** is to identify the equipment which a hydrogen combustion plant will require that differs from a typical combustion plant, and the spatial footprint associated with each piece of equipment.*

The following section considers the impact of hydrogen as a fuel on the footprint of the proposed facility relative to a natural gas equivalent.

3.3.1 Additional elements

3.3.1.1 Supply infrastructure

For new build sites where hydrogen is the sole fuel, then the footprint required for the receiving facilities (isolation valves, remote shut-off valve and custody metering) will be comparable to that of a natural gas equivalent. While there will be a difference in pipe diameters as a result of the lower energy density, from a plot-wide perspective this has a negligible impact.

For sites with both hydrogen and natural gas supply installed in parallel, then the additional footprint required for the hydrogen receiving facilities will be approximately 20 to 50 m^2 for low pressure systems (<10 barg) and as much as 900 m^2 for high pressure systems that include fuel gas compressors.

3.3.1.2 Hydrogen storage

The footprint requirement for hydrogen storage is dependent upon the inventory required. Table 9 outlines the approximate footprint for some typical storage options and range of scale. Footprint and plot size includes spacing requirements, ancillary equipment, and refrigeration units for handling boil off gas in the cryogenic options.

Table 9. Hydrogen storage options considered for case study

	2 x 228 barg tube trailers	2 x 300 barg tube trailers	350 barg horizontal bullets	Small cryogenic sphere	Large cryogenic sphere
Hydrogen phase	Gas	Gas	Gas	Liquid	Liquid
Inventory per vessel (te)	0.6	0.9	1.21	38	270
Number of vessels (-)	2	2	4	1	1
Total inventory (te)	1.2	1.8	4.85	38	270
Plot dimensions (m x m)	25 x 30	25 x 30	35 x 45	30 x 30	45 x 50
Area (m^2)	750	750	1,575	900	2,250
Specific footprint (m^2/te)	625	417	325	24	8

To contextualise the storage, the hold-up time for each storage option was considered and summarised in Table 12.

3.3.1.3 Hydrogen blending

For sites that will blend hydrogen with natural gas or a diluent, then a series of isolation valves, control valves and metering with supporting control and electrical equipment will be required.

These are typically package equipment items that are supplied on skids or in ISO containers. The anticipated footprint for such a package will be equivalent to that of a 10ft or 40ft ISO container. This would result in a footprint between 7 m² (2.43 x 2.80 m) and 30 m² (2.43 x 12.2 m).

3.3.1.4 Combustor/burner modifications

The required combustor/burner type modifications will depend on the type of combustion system e.g. premixed such as in state-of-the-art heavy duty gas turbines or diffusion such as industrial gas turbines. Dry type pre-mixed low NOx combustors and burners are the most common applied on new builds and retrofits firing natural gas. The types of burners can be utilised in high hydrogen service; however, they typically generate NOx levels that are higher than environmental standards permit and subsequent treatment of flue gas is required.

Most Original Equipment Manufacturers (OEMs) for combustion systems other than gas turbines are developing alternative burners that are either staged or diffusion type combustors that allow a wider range of fuels to be burned while minimising NOx generation. These new types of combustors when installed as part of new build projects and retrofit applications are anticipated to have no impact on footprint and may mitigate or reduce the size of downstream SCR units.

An alternative solution is to implement a combustor that relies on water injection and will require a water injection package skid, as well as incur an associated energy penalty. The water injection packages themselves are relatively small and typically less than 4 m². Much of the equipment associated with water injection is housed within vacant space inside the gas turbine enclosure and will not result in an increase of the overall footprint.

There are footprint implications where the water available on site is not suitable for the injection package. In this scenario, additional water treatment facilities would need to be installed. The additional footprint will be site specific and depend upon the quality of the raw water available (i.e. potable, river or sea water).

3.3.1.5 Flue gas recirculation

The design and space required for flue gas recirculation is equipment specific. While the application of flue gas recirculation (FGR) on gas turbines and reciprocating engines in commercial operation is very limited, it is not uncommon for boilers. For boilers, FGR is typically used to moderate flame temperature, reduce oxygen concentration and therefore reduce NOx. FGR is particularly effective on natural gas boilers where the majority of NOx tends to be produced by the thermal pathway.

Typically, the additional footprint for FGR on boilers is minimal, with the ducting running very close or over the top the boiler housing. For systems that require additional fans to recirculate the flue gas, then the equipment would need to be sized based on the application, NOx limits and fuel type to determine the footprint and it is difficult to suggest a generic allowance.

3.3.1.6 NOx emissions abatement

The higher flame temperature associated with hydrogen combustion has the potential to generate levels of NOx that exceed current environmental performance limits. Where abatement of emissions from the hydrogen/blend combustion process is required, consideration of these additional equipment items is required:

- ammonia/urea storage,
- reactant pumps,
- reactant control skid, and
- catalytic grid and housing

To evaluate the impact of incorporating post-combustion emissions abatement, the requirement for the above listed equipment has been specified in the case studies as an optional item and footprint broken out from the overall estimate.

The NOx emissions assumed for each of the case studies are summarised below in Table 10.

Table 10 NOx Input and Output Emissions, NO_X concentrations, dry, at 273.15K and 101.3kPa, and reference O_2 concentration, ammonia slip reported in kg/hr

#	Case Study	Reference O_2% for correction (vol%)	Inlet NOx (ppmvd)	SCR NOx Reduction Effectiveness basis	Outlet NOx (ppmvd)	Outlet NOx (kg/hr at 100% load)	Ammonia Slip (kg/hr)	Outlet (kgNOx/ MWh)
1	CCGT - Small	15	400	90%	40	73.8	4.59	0.34
2	CCGT - Medium	15	400	90%	40	132.7	7.36	0.33
3	CCGT - Large	15	400	90%	40	240.3	11.0	0.30
4	CCGT (CHP) - Small	15	400	90%	40	6.52	0.52	0.42
5	CCGT (CHP) - Medium	15	400	90%	40	13.4	0.88	0.37
6	CCGT (CHP) - Large	15	400	90%	40	21.3	1.26	0.35
7	OCGT - Small	15	400	90%	40	1.35	0.10	0.74
8	OCGT - Medium	15	400	90%	40	2.50	0.17	0.63
9	OCGT - Large	15	400	90%	40	140.4	7.34	0.46
10	Boiler (CHP) - Small	3	400	90%	40	1.94	0.08	0.20
11	Boiler (CHP) - Medium	3	400	90%	40	9.70	0.72	0.16
12	Boiler (CHP) - Large	3	400	90%	40	21.5	1.44	0.15

13	Reciprocating Engine - Small	15	400	90%	40	0.16	0.02	0.44
14	Reciprocating Engine - Medium	15	400	90%	40	2.65	0.22	0.41
15	Reciprocating Engine - Large	15	400	90%	40	13.8	1.02	0.40

3.3.1.7 Ammonia Slip

Ammonia slip is a term referring to the unreacted ammonia emitted from the SCR due to incomplete reaction of the reagent. Preferably, this slip should be kept as low as possible as it has the potential to cause unwanted consequences. These include the formation of ammonium sulphates which can lead to corrosion or plug formation in downstream components, increased plume visibility, as well as downwind nitrogen deposition effects. Typical allowable slip levels are in the range of 2-10 ppm since these levels do not pose a risk to human health or cause plume formation[16]. 5 ppmvd slip has been assumed as a general indicative basis for all case studies.

3.3.1.8 Maintenance, laydown and stores requirements

The additional land required for maintenance, laydown and stores is anticipated to be similar for both natural gas and hydrogen fuelled plants.

Where developers opt to install both natural gas and hydrogen infrastructure then additional area within the stores building will be required for additional spares, however this likely to have a negligible impact on the overall footprint of the plant.

Where SCR is required for NOx abatement, there will be additional footprint associated with areas for lifting equipment and access to the tanks and pumps, which has been included in the allowance for the SCR unit in the case studies.

3.3.2 Retrofit considerations

3.3.2.1 Piping material incompatibility

Where the implementation of hydrogen has not been foreseen the existing fuel gas system materials may be incompatible with hydrogen service. The pipework that operates at high pressures and temperatures will be of particular concern as these factors increase the risk of embrittlement.

In such scenarios, site owners will need to consider the replacement of existing pipework in its current location or run new lines specified for hydrogen service alongside the existing natural gas system. This decision will be driven by costs and outage time requirements. While utilising the routing of the existing natural gas line for the replacement hydrogen line will have limited impact on the footprint requirements it could result in a lengthy outage of the plant while it is replaced. Installing a new hydrogen line in parallel to the existing lines while still in operation is likely to be less disruptive.

While pre-investment is typically discouraged by developers to minimise capital expenditure, the cost of pre-investing in wider piperack and sleeper ways to accommodate a future hydrogen line may be minimal.

With respect to the checklists, it is recommended that for projects that are not designed to operate on fuels with high hydrogen concentrations initially, that the natural gas pipework either be specified and sized to accommodate 100 vol% hydrogen or that the pipe routing and infrastructure include pre-investment to support hydrogen service in the future. This recommendation is addressed in B3(a) of the new checklists.

3.3.2.2 Fuel gas compressor design and power demand

For large gas turbines operating with either gas-fired or hydrogen-fired technology, fuel gas supply pressures of more than 30 barg are typical and can be as high as 50 barg in some instances depending

[16] US Environmental Protection Agency, Air Pollution Control Technology Fact Sheet, https://www3.epa.gov/ttncatc1/dir1/fsncr.pdf

on the gas turbine compressor pressure ratio. These inlet pressures pose challenges with piping and compression technology selection.

3.3.2.3 Equipment ATEX classification and hazard zone radii

In Section 3.2.4.2 the implications of DSEAR and ATEX regulations were discussed, and equipment located within hazardous zones are required to meet a higher standard of specification for hydrogen service relative to natural gas. The transport properties of hydrogen also differ from natural gas, which combined with the smaller molecule size and wider flammability limits can increase the size of hazardous zones around potential leak and vent points relative to natural gas.

Where equipment and instrumentation are either not ATEX rated or suitably specified for less onerous requirements (i.e. IIA rather than IIC) there are four common solutions:

1. Eliminate the leak or vent point (i.e. replace flanged connection with welded joint, or increase vent height),
2. Move equipment outside of the hazardous zone,
3. Increase ventilation to reduce extent of hazardous zones, or
4. Replace equipment items with suitably rated ATEX equivalent.

Options 1 and 2 may lead to an increase in footprint, while option 3 and 4will have no impact on footprint. In each case the most cost-effective solution will vary and need to be assessed.

3.3.2.4 Installation of SCR grid

Most new natural gas combustion equipment for large power generators can achieve the levels of NOx emissions required to comply with environmental regulations and permits without the addition of SCR to treat the flue gas. However, power generation equipment OEMs are actively developing combustors and burners that can maintain the required environmental performance with hydrogen (and therefore avoid the costs and potential for ammonia impacts from SCR). Given the current state of the development of low-NOx combustion, it is prudent to assume that sites may wish to deploy SCR to reduce the increased NOx generated through secondary means to supplement any primary reduction techniques. In addition, sites may wish to provision for future installation of SCR in case regulations change in the future.

While the need to install SCR prior to hydrogen firing is not mandated, the guidance should require sufficient space be allowed for the injection grid and catalyst within the downstream ducting/HRSG and that sufficient space be reserved from ammonia or urea storage.

It should be noted OEMs are actively researching and developing technology in this area and may successfully eliminate the need for SCR by achieving the require NOx compliance with combustor technology advances alone.

3.3.3 Footprint estimation

A concept level design using a number of representative configurations as case studies were used to produce footprint estimates for onsite assets with a clear and consistent defined basis. The intent is that the results of these case studies provide an evidence base that can be used by examiners during the application process to determine if the acceptance criteria for assessments 1 and 4, defined in Section 1.2, have been addressed appropriately by developers.

3.3.3.1 Case study basis

For additional information regarding the basis for the case studies, refer to Appendix D. However, the following key assumptions have been made with respect to the development of the case studies to determine a footprint:

- **Sites are dual-fuel, capable of operating on natural gas and hydrogen**
  Re-use of existing natural gas infrastructure for use with hydrogen may be possible, however for the purpose of the case studies the installation of natural gas and hydrogen infrastructure in parallel have been conservatively assumed.
- **Hydrogen supplied to site by pipeline**
  Truck delivery of hydrogen to site is a potential solution for power plants with relatively small

energy demand or peaking operation and is subject to further discussion in Section 3.5. To provide a consistent basis across all cases hydrogen supplied by pipeline to site has been assumed.

- **No on-site production or storage of hydrogen**
  The premise of the report is on decarbonisation readiness of combustion equipment and power generators. The generation of hydrogen is broad topic in its own right and the footprint required is dependent upon a larger number of variables. This aspect of the hydrogen supply chain is the subject of other BEIS studies and innovation competitions and as such is outside the scope of this project.
- **Dry low NOx type combustor/burners utilised**
  Dry low NOx type combustors/burners have been assumed across all cases.
- **SCR assumed for NOx abatement**
  Technology providers and OEMs are actively working to develop combustor technology to mitigate NOx generation and potentially minimise and eliminate the requirement for SCR downstream of combustion, however SCR has been assumed as required for the case studies to provide a conservative basis for footprint estimation.

3.3.3.2 Analysis of case study results

The results of the case studies are summarised in Table 11. Further information is provided in the appendices.

Table 11. Summary of case study footprint estimates

		Data for Benchmarking			Footprint			Total footprint, hydrogen firing	
#	Case Study	Plant Net Output (MWe)	Plant Energy Input (MW.th)	Plant H_2 consumption (t/h)	Base Plant (m²)	Add. Hydrogen infrastructure (m²)	Additional SCR (m²)	Absolute (m²)	Specific (m²/MW.th)
1	CCGT - Small	218.0	402.0	15.5	26,293	39	69	26,400	66
2	CCGT - Medium	405.1	722.5	27.9	31,361	84	104	31,549	44
3	CCGT - Large	805.9	1,307	50.5	45,580	135	164	45,880	35
4	CCGT (CHP) - Small	15.4	35.7	1.38	5,799	13	12	5,824	163
5	CCGT (CHP) - Medium	36.2	73.0	2.82	8,362	17	21	8,400	115
6	CCGT (CHP) - Large	61.2	116.2	4.49	15,634	24	39	15,688	135
7	OCGT - Small	1.81	7.35	0.28	548	3	1	552	75
8	OCGT - Medium	3.97	13.7	0.53	823	4	5	832	61
9	OCGT - Large	302.4	764.3	29.6	21,050	68	86	21,204	28
10	Boiler (CHP) - Small	9.51	31.9	1.23	9,789	7	5	9,800	307
11	Boiler (CHP) - Medium	61.8	159.3	6.16	23,832	25	23	23,881	150
12	Boiler (CHP) - Large	142.4	353.7	13.7	30,459	49	52	30,560	86
13	Reciprocating Engine - Small	0.98	2.33	0.09	1,001	0.5	1.2	1,003	431
14	Reciprocating Engine - Medium	12.3 (5 x 2.46)	27.5 (5 x 5.49)	1.06 (5 x 0.21)	2,369	8	12	2,389	87
15	Reciprocating Engine - Large	51.3 (5 x 10.3)	112.2 (5 x 22.4)	4.34 (5 x 0.87)	4,956	62	29	5,046	45

Notes:

1. Additional Hydrogen Infrastructure footprint includes hydrogen supply lines, pressure reducing station, blending package and BoP
2. Additional SCR footprint includes ammonia/urea storage, reactant pumps, reactant control skid, catalytic grid and housing. This item is segregated from the hydrogen infrastructure as dependent upon developments in burner technology it may not be required.
3. Specific footprint is based on an LHV value for the typical hydrogen fuel blend as defined in Appendix C.3 i.e. approximately 98vol% hydrogen with calculated LHV 93.1 MJ/kg.

Table 12. Summary of hold-up time for various storage options

#	Case Study	Plant H_2 consumption (t/h)	Storage hold-up time (hours): 2 x 228 barg tube trailers (1.2 tonne)	2 x 300 barg tube trailers (1.8 tonne)	4 x 350 barg horizontal bullets (4.85 tonne)	Small cryogenic sphere (38 tonne)	Large cryogenic sphere (270 tonne)
1	CCGT - Small	15.5	0.08	0.12	0.31	2.45	17.4
2	CCGT - Medium	27.9	0.04	0.06	0.17	1.36	9.68
3	CCGT - Large	50.5	0.02	0.04	0.10	0.75	5.35
4	CCGT (CHP) - Small	1.38	0.87	1.30	3.51	27.5	196
5	CCGT (CHP) - Medium	2.82	0.43	0.64	1.72	13.5	95.7
6	CCGT (CHP) - Large	4.49	0.27	0.40	1.08	8.46	60.1
7	OCGT - Small	0.28	4.29	6.43	17.3	136	964
8	OCGT - Medium	0.53	2.26	3.40	9.15	71.7	509
9	OCGT - Large	29.6	0.04	0.06	0.16	1.28	9.12
10	Boiler (CHP) - Small	1.23	0.98	1.46	3.94	30.9	220
11	Boiler (CHP) - Medium	6.16	0.19	0.29	0.79	6.17	43.8
12	Boiler (CHP) - Large	13.7	0.09	0.13	0.35	2.77	19.7
13	Reciprocating Engine - Small	0.09	13.3	20.0	53.9	422	3000
14	Reciprocating Engine - Medium	1.06 (5 x 0.21)	1.13	1.70	4.58	35.8	255
15	Reciprocating Engine - Large	4.34 (5 x 0.87)	0.28	0.41	1.12	8.76	62.2

3.3.4 Objective 1 Summary

Table 13 presents the overall summary in relation to the footprint of Hydrogen Readiness of conversion of natural gas sites.

Table 13. Summary of main footprint requirements for Hydrogen Readiness

Characteristic	Commentary
Supply infrastructure	• New build receiving infrastructure will be comparable to NG equivalent • Difference in pipe diameter will have minimal impact • Sites with both H2 and NG will need additional space of 20 – 50m^2 (low pressure systems) to 900m^2 (high pressure systems)
Hydrogen storage	• Dependent on inventory required • Economic case of full supply chain needs to be considered • Carbon footprint of full supply chain needs to be considered
Hydrogen blending	• Equipment (valves/ metering etc) typically available as skid mounted or ISO Containers requiring footprint of 10ft - 40ft ISO Container (7m^2 - 30m^2)
Combustor/burner modifications	• Replacement of Dry Low NOx type is negligible (preferred type on new build & retrofits); Wet Low NOx type will require a water injection package of <4m^2 footprint
Flue gas recirculation	• Equipment specific and cannot be generically assessed
Emissions abatement	• Consideration of additional equipment required including: – Ammonia/urea storage – Reactant pumps and control skid – Catalytic grid and housing • SCR has been included as an optional item with footprint broken out from overall estimate

3.4 Objective 2 – Checklists

***Objective 2** is to produce recommendations of the additional items to be added to the existing CCR checklist or generate a new checklist to identify the technical changes required to convert a plant to hydrogen combustion.*

The 2009 checklists were reviewed as part of this project and a workshop held with BEIS, EA and NRW for review. The comments and recommendations have been consolidated into the checklists provided in Appendix B.

The following section details some of the key topics and themes that were presented and discussed as part of the checklist workshops.

3.4.1 New checklist vs amendment of existing

To accommodate the recent technological advancement and scale of green hydrogen technologies, and the formation of green/blue hydrogen hubs in the UK, the 2009 carbon capture readiness guidance document and checklist require updating.

The 2009 guidance document includes 'Checklist B - Natural Gas Combined Cycle Power Station Using Pre-Combustion CO_2 Capture (including coal gasification) and Hydrogen-Rich Fuel Gas Combustion'. This, with some modification, can be applied to power generators proposing to use blue hydrogen (LCH or SMR with CCUS).

For power generators sourcing hydrogen from a hydrogen hub or on-site production via low carbon methods, at least one, and potentially two, additional checklists are required. The number and format of additional checklists has been discussed and the final checklist presented in Appendix C.

3.4.2 Assessment criteria for 'Hydrogen Readiness' of prime movers

For gas turbines and reciprocating engines, full hydrogen firing is not yet proven for the full range of products. While many OEMs have operating units demonstrating capability of firing Hydrogen blends, the extent of work required and viability of converting these units at a later date to full hydrogen firing will be difficult to assess by the examining authority with the current limited number of reference cases.

3.4.3 Minimum percentage volume of hydrogen at first fire

It is understood that, from a policy perspective, BEIS is reviewing the implementation timeline for sites to be fully hydrogen fired. Further discussion is required as to what would be the minimum percentage of decarbonisation acceptable, which in turn dictates the minimum volume of hydrogen in the fuel that would be acceptable to comply with Requirement 5 in Section 1.2. In addition, the full composition of the blend should be understood as this will have an impact on its carbon intensity.

3.4.4 Demonstrating low carbon electricity import

For sites that would propose to produce and store electrolysis-produced hydrogen on site for peaking plant operations, the electrical power imported needs to be from low-carbon sources in order for decarbonisation objectives to be achieved. As part of the workshop BEIS advised that the assessment criteria and level of proof of the low carbon credentials of the hydrogen supplier is being investigated through the UK Low Carbon Hydrogen Standard[17] work, which is being delivered by BEIS (consultation for which was completed in October 2021 and published April 2022) and is outside the scope of this project.

3.4.5 Demonstrating viability to connect to a hydrogen hub

The procedure for applying to connect to the National Grid's NTS system for the supply of natural gas is mature and regulated. As part of that application process National Grid, as the natural gas network operator, undertake a detailed study of the network capacity and delivery pressures that will be guaranteed at the site's battery limit. On completion of the connection study and acceptance of the

[17] BEIS, 2021, Designing a UK Low Carbon Hydrogen Standard, https://www.gov.uk/government/publications/uk-low-carbon-hydrogen-standard-emissions-reporting-and-sustainability-criteria, accessed 04 May 2022.

application, the developer will enter into an agreement to secure capacity during the development phase of the project. The confirmation of this agreement is a matter of public record, as it is a regulated industry, and is easily verified by the Examining Authority.

Similar procedures are not yet established for hydrogen hubs and supply networks, and it is likely that the Examining Authority will need to rely on MoUs, or similar early phase legal documents, that will be unique to each project. These documents are commercial in nature and may be non-binding. It is envisaged that this will result in an increased burden on the examiner to verify that the site will be connected to a hydrogen hub in the future and that sufficient technical design has been completed.

3.4.6 Demonstrating low carbon credentials of a hydrogen hub

To achieve the ultimate aim of decarbonisation of power generation, the full supply chain has to be considered from the generation of hydrogen through to its combustion to generate power. The question was raised as to how to ensure this is implemented and what criteria and checks would be required accept the decarbonisation readiness of a proposed power generating facility that intends to be supplied from a hydrogen hub. In particular who is responsible within the permitting and planning process for ensuring that the checks that the supplier is producing low carbon hydrogen has been completed should be established. As part of the workshop BEIS advised that the assessment criteria and level of proof of the low carbon credentials of the hydrogen supplier is being investigated through the UK Low Carbon Hydrogen Standard[18] work, which is being delivered by BEIS (consultation for which was completed in October 2021 and published April 2022) and is outside the scope of this project.

3.5 Objective 3 – Hydrogen Supply Chain

Objective 3 *is to research the alternatives to pipeline hydrogen fuel access e.g. on-site production, on-site storage, transport by road etc. and to determine their potential for the future.*

Hydrogen production can be produced by a variety of means, with production from natural gas (primarily Steam Methane Reforming (SMR)) currently accounting for almost 76%, 23% from coal and approximately 2% from electrolysis[19].

This section identifies alternative methods of deploying hydrogen to generating plant, where a pipeline connection is unavailable. It aims to identify the requirements for, and barriers to, deploying alternative methods of supplying hydrogen to the generating plant. It assesses options in three areas:

5. On-site production of hydrogen from fossil fuels with Carbon Capture and Storage
6. On-site production using electrolysis of water
7. Adoption of tanker or trailer units to deliver hydrogen from an off-site production location.

3.5.1 On-site Production: Blue Hydrogen

There are a number of technologies that can be combined with Carbon Capture and Storage to produce “blue” hydrogen. Blue hydrogen can be produced via steam methane reforming (using water as an oxidant and a source of hydrogen), partial oxidation (using oxygen as the oxidant), or a combination of both or autothermal reforming (ATR).

Steam Methane Reforming (SMR) is currently the principal technology used in the commercial production of hydrogen. However, it produces between 8kg and 12kg of CO_2 per kg of hydrogen in the current state-of-the-art (which may be captured in a separate process). An alternative process is being explored in the HyNet and Acorn projects which uses Johnson Matthey’s Low Carbon Hydrogen (LCH) technology. Both these technologies are explored in more detail in the following sections.

3.5.1.1 Steam Methane Reforming (SMR)

[18] BEIS, 2021, Designing a UK Low Carbon Hydrogen Standard, https://www.gov.uk/government/consultations/designing-a-uk-low-carbon-hydrogen-standard, accessed 15 March 2022.
[19] IEA, June 2019, The Future of Hydrogen: Seizing Today’s Opportunities

SMR is the most widely adopted method of producing hydrogen at large scale from natural gas. It is a process that uses natural gas as both the fuel and the feedstock (typically 30-40% of the natural gas is combusted in the process resulting in a flue gas of diluted CO_2). The process itself involves reacting superheated steam with natural gas in a reformer to produce a syngas of hydrogen and carbon dioxide. This syngas is cooled before passing through a Water Gas Shift process where Carbon Monoxide in the syngas is converted into hydrogen and carbon dioxide using steam. The hydrogen is separated using Pressure Swing Adsorption (PSA)[20]. The process is illustrated in Figure 6.

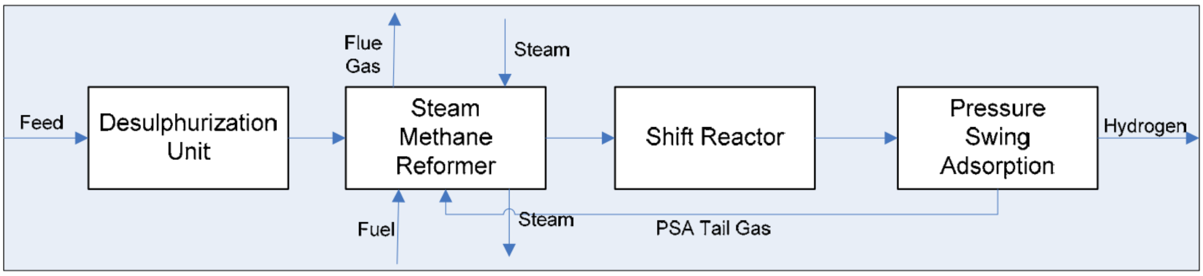


Figure 6 Hydrogen Production from Steam Methane Reforming

The process produces few wastes, chemical storage or liquid effluents but produces a flue gas which contains a dilute stream of CO_2 which can be captured in a carbon capture plant. In excess of 90% of the CO_2 can be captured from the flue gas stream, although CO_2 capture can also be achieved prior to the PSA (~60% CO_2 capture) or on the PSA Tail Gas stream (~55% CO_2 capture)[21].

The process will require the generation of superheated steam which will result in an energy penalty in its production. It will also require a suitable water treatment facility to produce water of a suitable quality.

The process typically yields 3 to 4 moles of hydrogen per mole of feedstock[22].

Wood undertook a benchmarking study for Novel (Next Generation) UK Carbon Capture Technology on behalf of BEIS[23] which included a case study for Steam Methane Reforming (SMR) of natural gas with carbon capture. This case study assumed the production of 100,000 Nm^3/h of 99.99% purity hydrogen.

The overall capex costs of the project were estimated by Wood at £237.3 million against £144.1 million for an unabated SMR process of the same scale (see Table 14) with a claimed accuracy of ± 30%[24].

Table 14 Economic Performance

	Units	Reference Case (Unabated SMR)	Natural Gas SMR with Cansolv CCS
CAPEX			
Pre-Licensing & Design	£ million	1.3	2.1
Regulatory & Public Enquiry	£ million	2.7	4.5
EPC Contract Cost	£ million	127.4	207.2
Infrastructure Connections	£ million	3.8	9.0

[20] EIGA, 2009, Best Available Techniques for Hydrogen Production by Steam Methane Reforming, 155/09/E
[21] IEA, 2019, The Future of Hydrogen
[22] EIGA, 2009, Best Available Techniques for Hydrogen Production by Steam Methane Reforming, 155/09/E
[23] Wood, 8th October 2018, Assessing the Cost Reduction Potential and Competitiveness of Novel (Next Generation) UK Carbon Capture Technology, Benchmarking State-of-the-art and Next Generation Technologies, BEIS, 13333-8820-RP-001, Revision: 4A
[24] Wood, 8th October 2018, Assessing the Cost Reduction Potential and Competitiveness of Novel (Next Generation) UK Carbon Capture Technology, Benchmarking State-of-the-art and Next Generation Technologies, BEIS, 13333-8820-RP-001, Revision: 4A

Owner's Costs	£ million	8.9	14.5
Total CAPEX	**£ million**	**144.1**	**237.2**
OPEX			
Total Fixed OPEX	£ million pa	7.4	10.7
Total Variable OPEX (excl. Feed)	£ million pa	0.7	14.3
Average Feed Cost	£ million pa	72.6	70.2
Total Start-up Cost (excl. Fuel)	£ million	0.5	1.2

The footprint required for an SMR plant (with Carbon Capture) producing 100,000 Nm^3/h of hydrogen was estimated as 110m x 150m[25]. However, there are a number of suppliers such as Linde and Air Products that are providing skid or containerised SMR systems producing significantly lower quantities (the Linde HYDROPRIME system will produce 330 – 1,000 Nm^3/d[26] (30 – 90 kg/d)[27] and the Air Products Prism system will produce 2,000 – 5,000 Nm^3/d (200 – 500 kg/d)[28].

SMRs currently have a conversion efficiency of around 65%, but with future technological developments this is expected to increase to approximately 74%[29] including carbon capture.

Table 15 provides the estimated SMR requirements for a range of General Electric gas turbines at 100% hydrogen[30].

Table 15 Steam Methane Reforming Requirements Supporting 100% Hydrogen

Gas Turbine	Output† MW	Heat Input† GJ/h	100% H_2 Flow Rate kg/h	CO_2 Generated kg/h	tonnes/year
GE-10	11.2	129	~1,140	~6,250	~50,000
6B.03	44	473	~4,170	~22,900	~183,000
6F.03	87	857	~7,550	~41,500	~332,000
9F.04	288	2,677	~23,600	~130,000	~1,040,900
9HA.02	557	4,560	~40,200	~221,000	~1,800,000

† ISO conditions operating on natural gas and simple cycle operation. Heat input is High Heating Value.

[25] HyNET Low Carbon Hydrogen Plant, BEIS Hydrogen Supply Competition, Phase 1 report, V2 0518
[26] Linde, HYDROPRIME®. Modular hydrogen generators using steam-methane reforming. https://www.linde-engineering.com/en/process-plants/furnaces_fired_heaters_incinerators_and_t-thermal/steam_reformer_furnaces/index/hydroprime.html Accessed 16 March 2022
[27] Assumes a conversion of 1kg Hydrogen = 11.1 Nm^3
[28] Air Products, PRISM® Hydrogen Generation Systems https://www.airproducts.co.uk/supply-modes/gen-gas-on-site/onsite-hydrogen-generation
[29] Committee on Climate Change, November 2018, Hydrogen in a low-carbon economy
[30] Dr J Goldmeer, February 2019, POWER TO GAS: HYDROGEN FOR POWER GENERATION; Fuel Flexible Gas Turbines as Enablers for a Low or Reduced Carbon Energy Ecosystem, GE Power, GEA33861
Available at: https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861%20-%20Fuel%20Flexible%20Gas%20Turbines%20as%20Enablers%20for%20a%20Low%20Carbon%20Energy%20Ecosystem.pdf Accessed 17th February 2022

Novel processes such as the Sorption Enhanced SMR with CO_2 removal are being explored to reduce costs, but this technology is currently at a research level of TRL4[31]. However, if the technology becomes viable it offers the potential to produce more hydrogen at lower costs[32].

3.5.1.2 Low Carbon Hydrogen (LCH)

Johnson Matthey's Low Carbon Hydrogen (LCH) technology is being proposed for the HyNet North West (HyNet) project. The process is illustrated by the flowsheet in Figure 7[33].

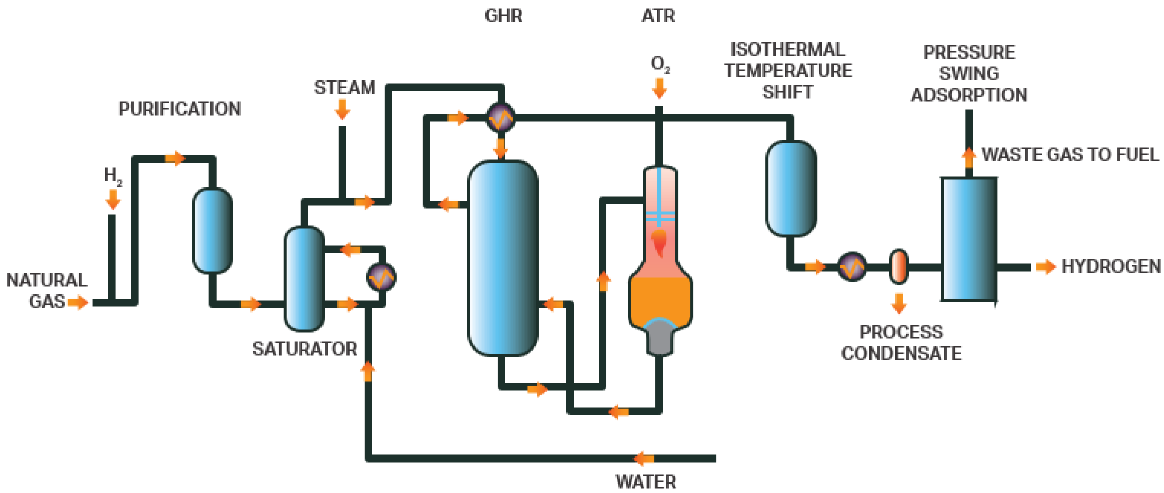


Figure 7 Johnson Matthey LCH Flowsheet

The process couples a Gas Heated Reformer (GHR) with an Autothermal Reformer (ATR) instead of adopting SMR. It differs from SMR process as oxygen is used as the energy to drive the process rather than the combustion of natural gas. The oxygen would be supplied by an on-site Air Separation Unit (ASU). For sites without on-site ASU, the source of the oxygen requires consideration, and for all cases, the energy associated with generating the oxygen for the purpose of supplying the reforming process should be considered to present a like-for-like comparison with traditional SMR or other air-blown reforming processes.

GHR's and ATR's are mature technologies which are currently used in the large-scale production of syngas for methanol and Fischer-Tropsch processes.

Compared to a conventional SMR process, the HyNet project states that the LCH process will consume 20% less feedstock gas and emit ~70% less CO_2 for the same hydrogen output. Comparison between the two processes as provided from the HyNet Phase 2 report to BEIS are illustrated in Table 16[34].

Note that recent developments in post-combustion carbon capture projects for CCGT flue gas have targeted capture rates significantly higher than 90%. Multiple projects have publicly stated an intent to capture up to 95% of emissions and higher with modest additional cost. CCGT flue gas has a lower CO_2 concentration (and therefore more challenging to achieve high capture fractions) than SMR flue gas, and therefore the reference capture rate for the SMR counterfactual in Table 16 at 90.1% should be viewed as a pessimistic estimate for the level of capture feasible from SMR technology.

[31] Cranfield University, The Gas Technology Institute, Doosan Babcock, Bulk Hydrogen Production by Sorbent Enhanced Steam Reforming (HyPER) Project, TRN 2039/09/2019
[32] Cranfield University, The Gas Technology Institute, Doosan Babcock, Bulk Hydrogen Production by Sorbent Enhanced Steam Reforming (HyPER) Project, TRN 2039/09/2019
[33] HyNET Low Carbon Hydrogen Plant, BEIS Hydrogen Supply Competition, Phase 1 report, V2 0518
[34] HyNET Low Carbon Hydrogen Plant, BEIS Hydrogen Supply Competition, Phase 2 report, November 2021

Table 16 Comparative Plant Performance

Parameters	Units	SMR Counterfactual		HyNet
Feedstock		Natural Gas	Natural Gas	Natural Gas and Refinery Off-gas (ROG)
Hydrogen Product Flow Rate	MW_{th} (LHV) / (HHV)	300 / 354	300 / 354	300 / 354
	kNm^3/h	100	100	100
Hydrogen Purity	%	99.9	99.9	99.9
Efficiency (LHV) / (HHV) Basis	%	67.2 / 71.7	80.0 / 85.4	80.3 / 85.8
CO_2 Capture Rate	%	90.1	96.9	96.9
CO_2 Output Stream Purity	%	96.0	99.9	99.9
CO_2 Generated	t/h	82.0	76.8	73.9
CO_2 Captured	t/h	73.9	74.4	71.6
CO_2 Emitted	t/h	8.1	2.3	2.0
	kg CO_2 / kNm^3 H_2	81.2	23.8	23.0

The HyNet project assumes that two plants will be developed at the Stanlow Oil Refinery. The first plant is proposed to be a 350 MW_{th} plant (Basis of Design information illustrated in Table 17[35]) with the second plant being a 700 MW_{th} process.

Table 17 HyNet Plant 1 Basis of Design Information

Parameter	Basis of Design
Hydrogen Production	100 kNm^3/h (equivalent to 350 MW_{th})
Plant Turndown	Capable of turning down to 40% of maximum hydrogen production
Feedstocks	Natural Gas (up to 100% of feedstock energy at 100% output) ROG (up to 40% of feedstock energy at 100% output)
Availability	Target availability of 95% averaged over its lifetime
Carbon Capture Rate	Capture as CO_2 a minimum of 95% of the total carbon entering the plant with a target of 97%
Design Life	Designed for an operational life of 25 years

[35] HyNET Low Carbon Hydrogen Plant, BEIS Hydrogen Supply Competition, Phase 2 report, November 2021

The indicative footprint for the 350 MW_{th} plant is 67m x 111m[36] with specific details of the proposed plant layout available in the HyNet Phase 2 Report[37].

The HyNet schedule suggests that Plant 1 could be in operation as early as 2025, provided the Final Investment Decision (FID) is delivered in 2022, with Plant 2 being delivered in 2026 (see Figure 8)[38].

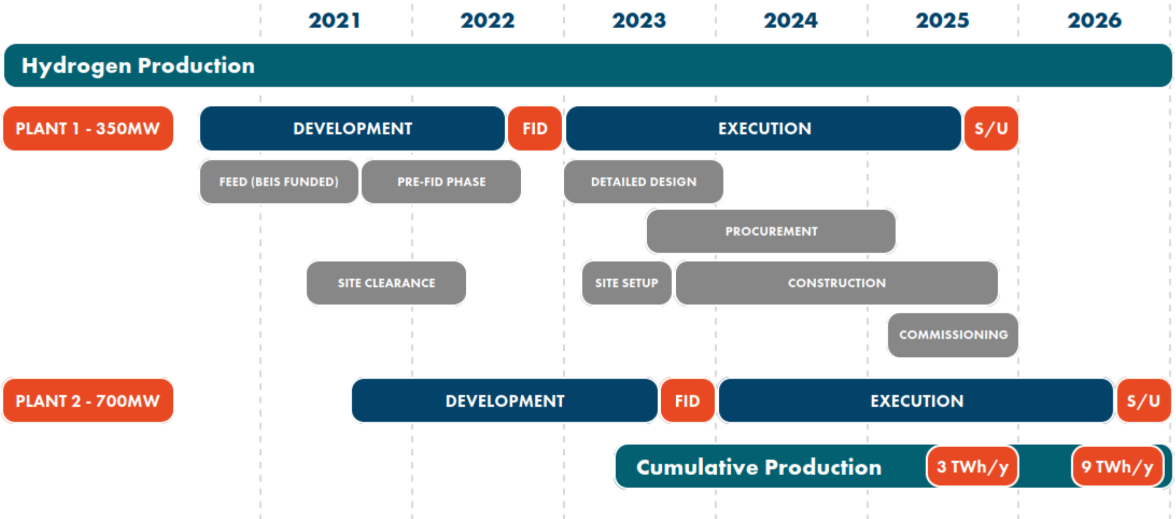


Figure 8 Plants 1 & 2 Project Schedule

The Class 4 capital cost estimate produced by HyNet[39] is summarised in Table 18, which identifies a CAPEX for the 350 MW_{th} unit as £253.9 million (for two and three similar units, the costs are estimated at £403.8 million and £569.8 million respectively). HyNet have assessed the OPEX costs at £13.2 million/y based on assumptions for natural gas, power, labour and CO_2 transport and storage.

Table 18 CAPEX Cost Estimate

Plant Element	350 MW_{th} Unit (£ million)
Site Preparation, Enabling and Facilities	12.5
Low Carbon Hydrogen Plant	55
Air / Gas Systems	137.3
Water Systems	14.3
Flare Systems and Infrastructure	8.6
Buildings	6.4
Connections and Common Systems	19.8
Total	**253.9**

[36] HyNET Low Carbon Hydrogen Plant, BEIS Hydrogen Supply Competition, Phase 1 report, V2 0518
[37] HyNET Low Carbon Hydrogen Plant, BEIS Hydrogen Supply Competition, Phase 2 report, November 2021
[38] HyNET Low Carbon Hydrogen Plant, BEIS Hydrogen Supply Competition, Phase 2 report, November 2021
[39] HyNET Low Carbon Hydrogen Plant, BEIS Hydrogen Supply Competition, Phase 1 report, V2 0518

3.5.2 On-site Production and storage: Electrolysis

The on-site production of hydrogen can also be provided through the electrolysis of water which, after drying and removing oxygen impurities, can produce hydrogen of >99.9% purity[40]. This can be achieved commercially using either Alkaline Electrolysis or Proton Exchange Membrane (PEM) Electrolysis. Emerging technologies such as Solid Oxide Electrolysis (SOEC) could also become available. Table 19 and Table 20 states the current and expected future main differences between the three technologies (as of 2019)[41].

Table 19 Current Electrolyser Characteristics

	Alkaline	PEM	SOEC
Electrical Efficiency (%LHV)	63 – 70	50 – 60	74 – 81
Operating Pressure (bar)	1 – 30	30 – 80	1
Operating Temperature (°C)	60 – 80	50 – 80	650 – 1,000
Stack Lifetime (hours)	60,000 – 90,000	30,000 – 90,000	10,000 – 30,000
Load Range (% relative to nominal load)	10 – 110	0 – 160	20 – 100
Plant Footprint (m^2/kWe)	0.095	0.048	Not yet commercialised
CAPEX (USD/kWe)	500 – 1,400	1,100 – 1,800	2,800 -5,600

Table 20 Estimated Future Electrolyser Characteristics

	Alkaline		PEM		SOEC	
	2030	Long Term	2030	Long Term	2030	Long Term
Electrical Efficiency (%LHV)	65 – 71	70 - 80	63 – 68	67 – 74	77 - 84	77 - 90
Stack Lifetime (hours)	90,000 – 100,000	100,000 – 150,000	60,000 – 90,000	100,000 – 150,000	40,000 – 60,000	75,000 – 100,000
CAPEX (USD/kWe)	400 – 850	200 - 700	650 – 1,500	200 - 900	800 – 2,800	500 – 1,000

The on-site production of hydrogen by electrolysis will require a suitable storage arrangement. Due to the efficiency of the electrolysis process this will be required to enable sufficient hydrogen to be available for generation purposes.

In addition to the electricity required the electrolysis process will require a significant quantity of water, which will vary with water quality:

[40] J. Brauns, T. Turek, Alkaline Water Electrolysis Powered by Renewable Energy: A Review, February 2020
[41] IEA, June 2019, The Future of Hydrogen: Seizing Today's Opportunities

- 0.9 litres of demineralised water per Nm^3 H_2, i.e. 10.5 litres water per kg hydrogen.
- 1.5 to 2.0 litres of potable water per Nm^3 H_2 is required, which will need to be demineralised via Reverse Osmosis typically resulting in a potable water requirement of 18 to 22 litres / kg hydrogen (or 0.45 to 0.55 litres per kWh HHV)[42] (0.55 – 0.65 litres per kWh LHV)

Table 21 gives an indication of the electrolyser requirement to supply a range of gas turbines from General Electric with 100 vol% hydrogen[43].

Table 21 Electrolysis Requirement Supporting 100% Hydrogen Operation

Gas Turbine	Output† MW	Heat Input† GJ/h	100% H_2 Flow Rate m³/h	t/h	Water Required to Generate H_2 m³/h	Electrolysis Power Required†† GWh
GE-10	11.2	129	~11,700	~1	~10	~500
6B.03	44	473	~43,000	~4	~37	~2,000
6F.03	87	857	~78,000	~7	~68	~3,600
9F.04	288	2,677	~243,500	~23	~212	~11,400
9HA.02	557	4,560	~415,000	~38	~361	~19,500

† ISO conditions operating on natural gas and simple cycle operation. Heat input is High Heating Value.

†† Power required for electrolysis to supply H_2 flow for gas turbine to operate on 100% H_2 for 8,000 hours

Electrolysers are scaling up quickly, from megawatt (MW)- to gigawatt (GW)-scale, as technology continues to develop. As illustrated in Table 20, electrolyser costs are projected to halve by 2040 to 2050[44]. Achieving technology scale-up and cost reductions are currently the most critical challenges, and R&D is also looking to improve power density, lifetime and balance of plant efficiencies[45].

Specific details about these electrolyser technologies are discussed in the following sections.

3.5.2.1 Alkaline Electrolysis

Alkaline electrolysis is a mature technology, having been used in industry since the 1920s. It is a technology that has been operated at scales in the region of 10's MW[46], with a system connected to a hydroelectric plant by Norsk Hydro (operating from 1948 to 1990) producing 70,000 kg H_2 /d[47] the largest plant is currently rated at 25 MW[48]. Small scale commercial containerised systems are available, for example Cummins produce a 50kW unit (HySTAT® 10-10) which produces hydrogen at 10 Nm^3/h (0.9 kg/h) in a 20ft ISO container[49]. McPhy also offer small scale units from 3kW[50] to 4MW (producing 0.4 Nm^3/h – 800 Nm^3/h) and are promoting an "Augmented McLyzer" technology which is based on a modularised system using their 4MW McLyzer 800-30 unit (note that a 20MW (4,000Nm^3/h) system developed in the Netherlands has a footprint of <900m^2)[51].

[42] Element Energy, November 2018, Hydrogen supply chain evidence base
[43] Dr J Goldmeer, February 2019, POWER TO GAS: HYDROGEN FOR POWER GENERATION; Fuel Flexible Gas Turbines as Enablers for a Low or Reduced Carbon Energy Ecosystem, GE Power, GEA33861
Available at: https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861%20-%20Fuel%20Flexible%20Gas%20Turbines%20as%20Enablers%20for%20a%20Low%20Carbon%20Energy%20Ecosystem.pdf Accessed 17th February 2022
[44] IRENA, September 2019, Hydrogen: A Renewable Energy Perspective
[45] IRENA, September 2018, Hydrogen from Renewable Power: Technology Outlook for the Energy Transition
[46] IEA, June 2019, The Future of Hydrogen: Seizing Today's Opportunities
[47] Z. Yan, J.L. Hitt, J.A. Turner, T.E. Mallouk, June 2020, Renewable electricity storage using electrolysis, www.pnas.org/cgi/doi/10.1073/pnas.1821686116
[48] IEA, 2021, Global Hydrogen Review, accessed 17 March 2022
[49] Cummins Inc, 2021, HYDROGEN: THE NEXT GENERATION, available at https://www.cummins.com/sites/default/files/2021-08/cummins-hydrogen-generation-brochure-20210603.pdf accessed 17 March 2022
[50] https://mcphy.com/en/equipment-services/electrolyzers/small/
[51] https://mcphy.com/en/equipment-services/electrolyzers/augmented/

It is a process that uses a concentrated electrolyte with a gas-impermeable separator to prevent the product gases from mixing. The electrodes consist of non-noble metals, e.g. nickel, with an electrocatalytic coating. A schematic flow diagram of the process is shown in Figure 9.

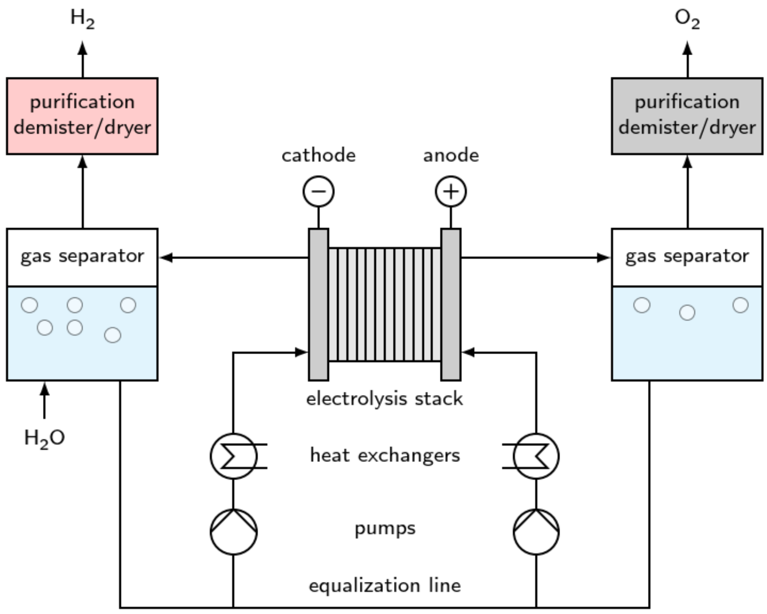


Figure 9 Schematic flow diagram of an alkaline water electrolyser

Lead times are identified as being in the region of 9 – 12 months[52].

Alkaline electrolysis has the advantage of technical maturity and relative low cost compared to the competing electrolyser technologies but it has low current density, restricted ability to operate at low loads and an inability to operate at high pressures.

3.5.2.2 PEM Electrolysis

PEM electrolyser technology is rapidly emerging and entering commercial deployment.

Due to the acidic nature of the PEM electrolysis process, catalysts are restricted to rare metals. Platinum at the cathode and Iridium Oxide at the anode is the current state of the art. In PEM electrolysis, water is added to the anode, where it is converted into oxygen, hydrogen ions (H^+) and electrons. The protons travel through a polymer membrane (most commonly of Nafion) to the cathode. The electrons travel from the anode through an external power circuit providing the driving force for the reaction. Once at the cathode, they recombine with the protons to produce hydrogen. This is demonstrated in Figure 10[53].

[52] SGN, KIWA, OREC, Arup, January 2020, Methilltoune Phase 1 Feasibility Design
[53] G Chisholm, L. Cronin, Storing Energy Chapter 16 Hydrogen From Water Electrolysis, 2016

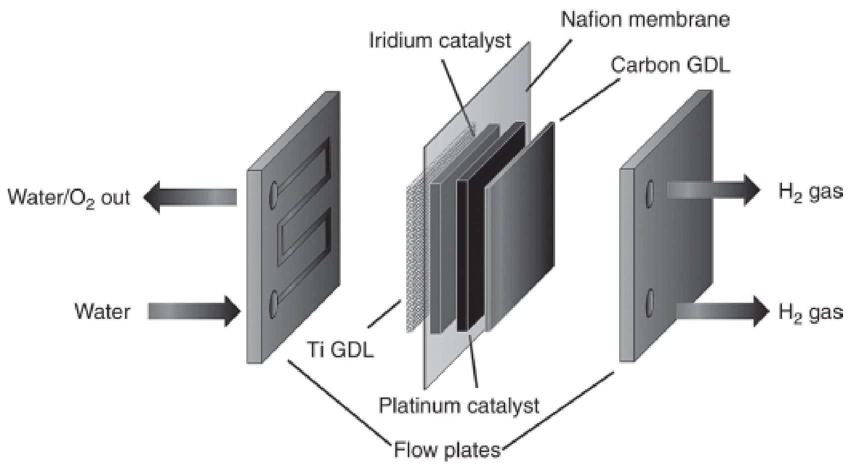


Figure 10 Cell Layout Diagram for a PEM Electrolyser

The PEM process benefits from a fast response, flexible operation and a high current density, which is twice that of Alkaline Electrolysis. This can lead to increased efficiency and reduced system footprint and capital cost, as illustrated in Table 19. The PEM electrolyser also benefits from low temperature operation and is capable of self-pressurising, which means that, while Alkaline Electrolysis generates hydrogen gas at pressures up to 30 bar, PEM electrolysis can achieve elevated outlet pressures in excess of 80 bar[54].

Systems can be maintained in stand-by mode with minimal power consumption and are able to operate for a short time period (10– 30 minutes) at a higher capacity than nominal load i.e. in excess of 100 %. Due to its regulation ability, a PEM electrolyser can supply hydrogen at the same time as providing ancillary services to the grid, provided that sufficient hydrogen storage is available.

Unlike most power sector assets, PEM electrolysers operate more efficiently when operated below nominal load.

The use of noble metals like platinum and iridium oxide in the electrodes makes the PEM process more expensive than Alkaline Electrolysis. Note that increasing current density does increase the power consumption per unit of hydrogen, and operation above 1 A/cm^2 is likely to reduce electrode life[55].

Typical systems will comprise the electrolyser, balance of plant (water treatment, gas conditioning, gas compression, electrical grid connections etc) and gas storage. The Energie Park Mainz system[56] which was commissioned in 2015 is an example of a typical PEM electrolyser system producing hydrogen for road transport and gas grid injection. Details of the system are:

- Electrolysers: Siemens Silyzer 200 PEM electrolyser continuous operation at 1.3MW each, peak power <2.0 MW per electrolyser; 35 bar output pressure, 20kg/h / 225 Nm^3/h hydrogen production per stack, dimension of each electrolyser skid of 6.3 x 3.1 x 3.0m
- Gas Storage: 700kg storage (2 tanks of 82m^3 at 20 – 80 bar)
- Compression: Ionic Compressor; Maximum volume flow 112 kg/h; 15 bar minimum suction pressure; 250 bar maximum pressure; 350 kW maximum power consumption; 10 – 100% load range

Containerised systems are available from a number of OEM's, capable of producing up to 500 Nm^3/h (~1,000 kg/d) of hydrogen and requiring two 40ft ISO containers with an overall footprint of 18m x 11m (~198^{m2})[57]. However, latest developments suggest production is moving towards factory scale facilities delivering double digit MW production (Siemens have recently introduced the Silyzer 300 which has a capacity of 17.5MW$_e$, 335kg H_2 per hour per full module array (24 modules) at 75% efficiency[58] (note

[54] CSIRO, March 2016, Cost assessment of hydrogen production from PV and electrolysis
[55] CSIRO, March 2016, Cost assessment of hydrogen production from PV and electrolysis
[56] https://www.energiepark-mainz.de/en/
[57] 5676517 HyLYZER 400/500 PEM Electrolyzers Spec Sheet - A4, Available at https://www.cummins.com/new-power/applications/about-hydrogen
[58] Siemens Energy, Power-to-X: The crucial business on the way to a carbon-free world, Available at https://www.siemens-energy.com/global/en/offerings/renewable-energy/hydrogen-solutions.html

for an array of 70MW/ 1,300kg/h hydrogen production would have a nominal plant footprint of 70 x 25m)[59]). Footprint for various scales of PEM electrolyser (based on Siemens Silyzer technology[60])

- 1.25MW: 10m x 10m (1 x Silyzer 200 indoor)
- 2.5MW: 14m x 20m (2 x Silyzer 200 indoor)
- 5MW: 40m x 10m (4 x Silyzer 200 indoor)

Past performance demonstrates that the scale of electrolysers has increased 10-fold every 4 to 5 years[61]. The current approach taken by most manufacturers is to develop modules of 5 – 10MW in size, which would then be combined to produce systems of 10's or 100's MW in scale[62] (see Figure 11 for a representation of the development of Siemens' PEM electrolyser[63]) . A cost reduction of 7% per doubling of installed capacity has been suggested[64]. Currently the largest PEM electrolyser in operation is 20MW at Air Liquide's facility in Becancour, Canada[65]

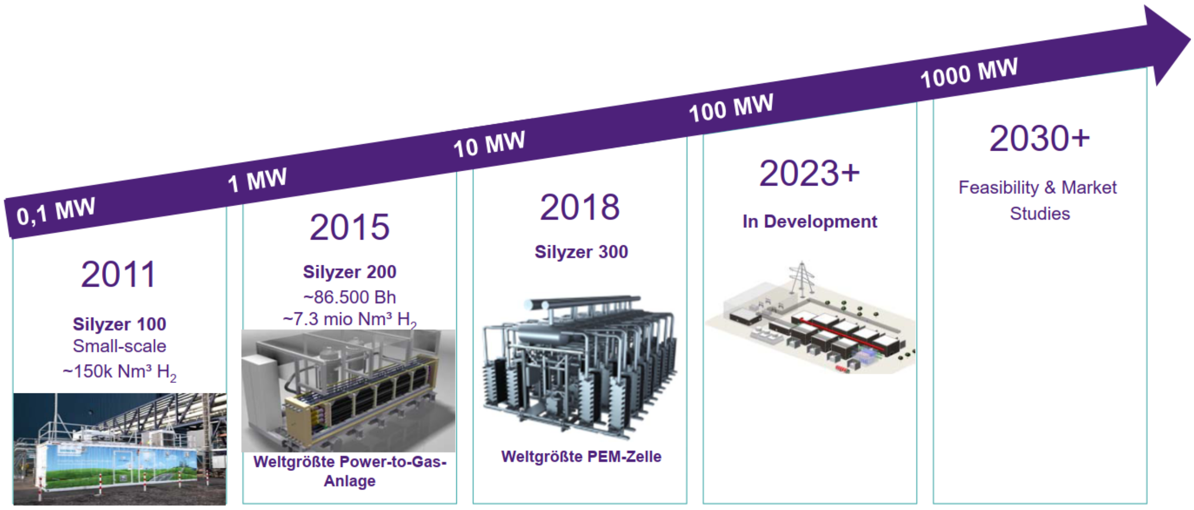


Figure 11 Evolution of Siemens' PEM Electrolyser

Lead time identified within literature is in the region of 12 – 18 months[66], which was corroborated by suppliers (Hydrogenics (now Cummins) identified a period of 12 – 15 months in 2020[67]).

3.5.2.3 SOEC

Solid Oxide Electrolysis (SOEC) is a technology that is at early-stage development[68] and less mature than either Alkaline or PEM electrolysis systems. Currently it has only been demonstrated at laboratory or pilot scale. It is a high-temperature technology in which steam is converted into hydrogen and water at temperatures of 700 °C to 900 °C at high pressure. Due to its thermodynamics, it is a process that has a theoretical stack efficiency of close to 100%[69] and has the potential for more favourable economics due to the use of ceramics and small quantities of rare materials for the catalyst compared to the PEM systems[70]. Other claimed advantages include the potential for the process to produce a synthesis gas directly from steam and CO_2.

[59] Siemens Energy, 2020, Overview of the PEM Silyzer Family, 2020-09-30 GIZ Workshop, https://4echile-datastore.s3.eu-central-1.amazonaws.com/wp-content/uploads/2020/10/10132733/20200930-SE-NEB-PEM-Electrolyzer-and-Applications_EW.pdf accessed 15 March 2022
[60] Siemens Energy, 2020, Overview of the PEM Silyzer Family, 2020-09-30 GIZ Workshop, https://4echile-datastore.s3.eu-central-1.amazonaws.com/wp-content/uploads/2020/10/10132733/20200930-SE-NEB-PEM-Electrolyzer-and-Applications_EW.pdf accessed 15 March 2022
[61] https://press.siemens-energy.com/global/en/feature/global-energy-transition-will-be-based-hydrogen-economy
[62] Element Energy, November 2018, Hydrogen supply chain evidence base
[63] Siemens Energy, 2020, Overview of the PEM Silyzer Family, 2020-09-30 GIZ Workshop, https://4echile-datastore.s3.eu-central-1.amazonaws.com/wp-content/uploads/2020/10/10132733/20200930-SE-NEB-PEM-Electrolyzer-and-Applications_EW.pdf accessed 15 March 2022
[64] Element Energy, November 2018, Hydrogen supply chain evidence base
[65] IEA, 2021, Global Hydrogen Review 2021, https://www.cleanenergyministerial.org/sites/default/files/2021-11/IEA%20Global%20Hydrogen%20Review%202021%20PDF.pdf
[66] SGN, KIWA, OREC, Arup, January 2020, Methilltoune Phase 1 Feasibility Design
[67] Personal Correspondence with B de Lannoy (Hydrogenics) 27th April 2020
[68] IRENA, September 2018, Hydrogen from Renewable Power: Technology Outlook for the Energy Transition
[69] J. Brauns, T. Turek, Alkaline Water Electrolysis Powered by Renewable Energy: A Review, February 2020
[70] IRENA, September 2018, Hydrogen from Renewable Power: Technology Outlook for the Energy Transition

The design of a SOEC process is shown in Figure 12[71].

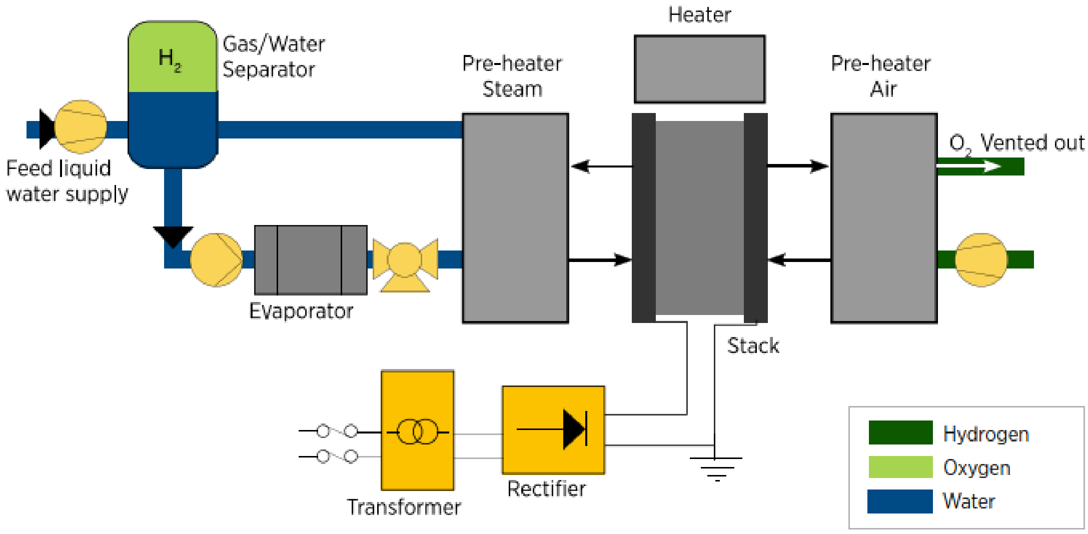


Figure 12 Generic system design and balance of plant for a solid oxide electrolyser

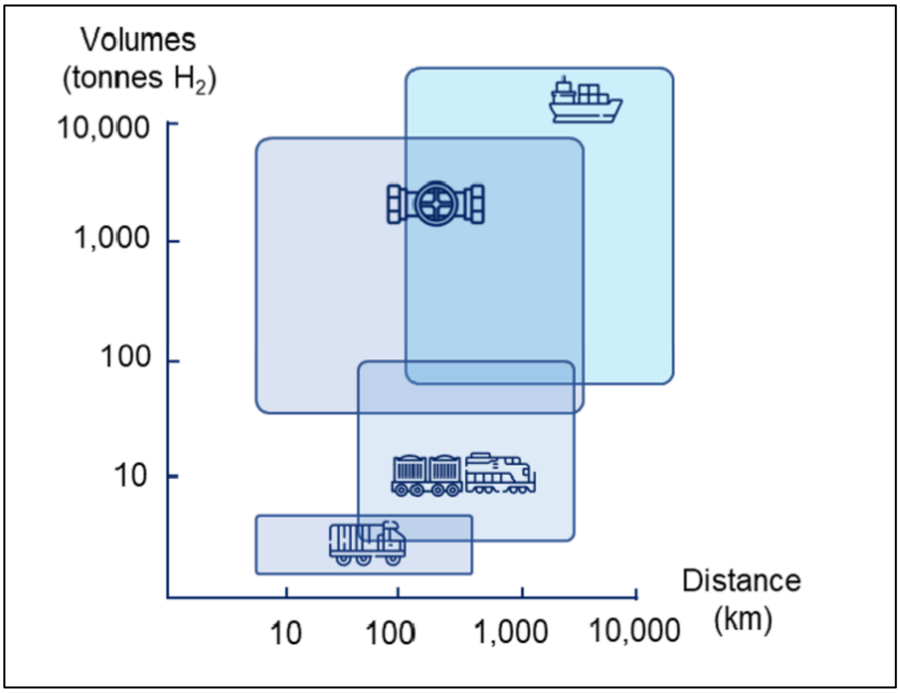
Due to the requirement for high temperature heat sources, this may reduce its long-term economic viability. Additionally, the process results in a corrosive environment which has an impact on material selection and is an area of current research[72]. Although at development stage, there are demonstration projects at 1MW scale [73], and are at pre-commercial proof of concept rather than commercial stage. Recent literature indicates that SOEC projects are aiming for 20MW scale in the short term[74] Haldor Topsoe indicates that a 100 MW (32,000 Nm^3/h hydrogen) SOEC facility would require a footprint of 8,400 m^2[75].

3.5.3 Road Delivery from Off-site Production

Hydrogen is routinely transported from off-site production to point of use. This can be achieved by a variety of options, depending on the volume and distance to be travelled. This is illustrated in Figure 13, which shows that road haulage is the preference for short distances of small volumes, while shipping is used for larger volumes over longer distances[76].

[71] IRENA, 2020, GREEN HYDROGEN COST REDUCTION Scaling up Electrolysers to meet the 1.5°C Climate Goal
[72] J. Brauns, T. Turek, Alkaline Water Electrolysis Powered by Renewable Energy: A Review, February 2020
[73] IRENA, https://irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf
[74] IEA, 2021, Hydrogen Tracking Report, https://www.iea.org/reports/hydrogen accessed 17 March 2022
[75] Haldor-Topsoe, SOEC high-temperature electrolysis, https://www.topsoe.com/hubfs/DOWNLOADS/DOWNLOADS%20-%20Brochures/SOEC%20high-temperature%20electrolysis%20factsheet.pdf?hsCtaTracking=dc9b7bfd-4709-4e7e-acb5-39e76e956078%7C20d976e0-d884-4c00-9fcf-3af3d0850476 accessed 17 March 2022
[76] Element Energy Ltd. October 2020; Sustainable Hydrogen

Figure 13 Typical Modes of Transportation



3.5.3.1 Road Haulage

Transportation of low volumes of hydrogen, as either compressed gas or as a cryogenic liquid via road haulage (e.g. in tube trailers), is a well-established approach for low volumes over relatively short distances. Literature[77] suggests that 10 tonnes/day is the threshold of economic transportation of hydrogen by road. For distances of <300 km this is likely to be in a compressed gas form with liquefied hydrogen being favoured beyond 1,000 km (between 300 km and 1,000 km either form could be viable but would be assessed on a case-by-case basis).

Compressed gas is commonly transported by tube trailers. Typically a tube trailer will transport around 300 kg of hydrogen at approximately 228 bar (approximately 380kg at 250 bar[78]) although there are units on the market that can transport 600 kg at 228 bar and 900 kg at 300 bar. There are others being developed with the capacity to accommodate up to 1,000kg at 500 bar. Liquid hydrogen is transported in trailers with capacities up to 7,711 kg at 1.7 bara and -253°C[79] or between 2,000 and 7,500 kg as cryogenic liquid, are currently available.

Road haulage becomes less economic with increasing distance and with increasing demand, but remains an attractive near-term solution due to its low infrastructure cost and risk. In the longer term it may remain the best option for remote or low-demand areas. However, increased use of transportation by road would become prohibitive due to the relatively small volume contained within each tube trailer, and hence significant numbers of vehicles.[80]

Transport via the rail network offers opportunities to handle larger volumes of hydrogen over greater distances, provided the required infrastructure is in place.

Haulage logistics are a key project-specific challenge for any project wishing to bring externally-produced hydrogen to site by non-pipeline means. The quantity of hydrogen consumed at full load for each Case Study is shown in Table 12, as well as the corresponding storage time from storage of mobile tube trailers. The scope for road transportation is limited to the carrying capacity of each trailer, the logistics involved with the resulting truck movements and the number of parallel bays at the road truck transfer station at the receiving end. For the purposes of this study, it has been assumed that only

[77] BNEF, 2020, Hydrogen Economy Outlook
[78] https://www.energy.gov/eere/fuelcells/hydrogen-tube-trailers
[79] A. Brown, July 2020, Hydrogen: The future fuel today, Hydrogen Transport, IChemE
[80] Committee on Climate Change, November 2018, Hydrogen in a low-carbon economy

scenarios where at least one 4-hour shift of operation at full load could be supported by a single delivery of hydrogen would be feasible for batch resupply by road trucks.

3.5.3.2 Compressed Gas Pipelines

This is considered to be the most efficient method of transporting large quantities (>10 tonnes/day) of hydrogen over distances not requiring transport over oceans. This is considered to be the default method of hydrogen transportation to be adopted in the project.

Hydrogen's compatibility with the pipeline construction is an area of concern as, under high pressures, it can cause embrittlement and stress corrosion cracks in carbon steel pipes (ferritic steels are more susceptible than austenitic steels[81]) requiring an upgrade to existing repurposed pipelines. This is less of an issue at lower pressures and can also be reduced by operating at lower temperatures, material selection and conservative design (lower hoop stress)[82].

A programme of natural gas pipework replacement across the UK and Europe is in progress, where the existing infrastructure is being replaced with polythene pipes. These pipes are hydrogen compatible, but are currently limited to 7 bar. Pipes compatible with hydrogen gas up to 17 bar have been proposed. Hydrogen pipelines have long lifetimes (50–100 years)[83]. Additionally, programmes of work, for example HyNTS, Project Union and FutureGrid are being implemented to demonstrate the operation of the transmission network with hydrogen at pressure[84].

3.5.3.3 Shipping

The development of shipping as a mode of transportation for hydrogen would enable the development of global hydrogen supply chains. As illustrated in Figure 13, ships can transport large volumes, but this requires the necessary port infrastructure.

The transportation of liquid hydrogen by ship is currently at demonstration stage, with the first shipment having left Australia earlier this year[85]. Although scale-up of global supply chains could see its cost fall by up to 90% by 2030[86], alternatives such as ammonia are increasingly been seen as viable options with Shipment in this form becoming economic at approximately 2,000 km for 10 – 100 tonnes/day and from 5,000 km for volumes over 100 tonnes/day[87] [88] [89].

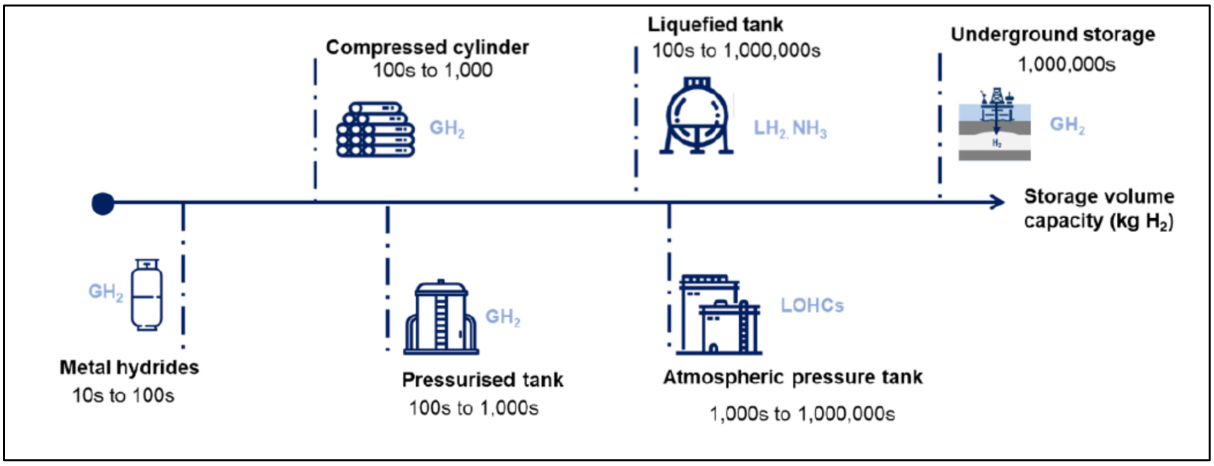
3.5.4 On-site Hydrogen Storage

Hydrogen is costly and technically challenging to store in large quantities. The introduction of storage capacity will result in additional capital and operating costs, as well as environmental and site restrictions (for example, it may require substantial areas of the site's available land).

The comparative storage options by kg of stored hydrogen are illustrated in Figure 14[90]. For an industrial scale development, the storage options are likely to be restricted to compressed gas in tanks, or liquefaction. These options are described below, with the particular option selected being dependent on site location, end market and operational considerations (e.g., storage duration requirements).

[81] A. Brown, July 2020, Hydrogen: The future fuel today, Hydrogen Transport, IChemE
[82] A. Brown, July 2020, Hydrogen: The future fuel today, Hydrogen Transport, IChemE
[83] Staffell I., Scamman D., Abad A. V., Balcombe P., Dodds P.E., Ekins P., Shahd N. and Warda K.R.; The role of hydrogen and fuel cells in the global energy system, *Energy Environ. Sci.*, 2019, **12**, 463
[84] National grid, February 2021, Hydrogen: the future fuel to achieve net zero?, available at https://www.nationalgrid.com/stories/journey-to-net-zero-stories/hydrogen-future-fuel-achieve-net-zero, Accessed 14 March 2022
[85] https://www.rechargenews.com/energy-transition/special-report-why-shipping-pure-hydrogen-around-the-world-might-already-be-dead-in-the-water/2-1-1155434
[86] Element Energy Ltd. October 2020; Sustainable Hydrogen
[87] https://www.rechargenews.com/energy-transition/special-report-why-shipping-pure-hydrogen-around-the-world-might-already-be-dead-in-the-water/2-1-1155434
[88] https://assets.new.siemens.com/siemens/assets/api/uuid:d37afbdb38cc8384fd7367f7bd15d5f9fc95eea6/version:1560355025/siemens-green-ammonia.pdf
[89] BNEF, 2020, Hydrogen Economy Outlook
[90] Element Energy Ltd. October 2020; Sustainable Hydrogen

Figure 14 Storage Approach for Representative Hydrogen Volumes (units in kg)



Liquid hydrogen (LH2) storage is typically used in industrial locations where demand for hydrogen is high, e.g., refineries. Industrial consumer storage tanks tend to have capacities between 110 and 5,300kg, with storage at centralised production sites being in excess of 100,000kg. Due to hydrogen's low boiling point compared to liquefied natural gas, the storage and handling of liquefied hydrogen is more expensive and requires energy input in the region of 30 – 40% of the LHV of the hydrogen being stored[91]. Additionally, evaporation of hydrogen will always occur, no matter how well insulated the vessel is. Rates depend on the surface area to volume ratio, but are typically from 2–3 %/day for small portable containers, down to 0.06 %/day for large vessels, with a typical rate being 0.1 %/day.

Compressed Gas Storage is a widely used approach which requires less energy than liquefaction and is easily scaled. However, it suffers from low volumetric energy density and requires significant energy input to get the hydrogen in and out of storage, with higher pressures increasing costs through higher storage vessel material and compressor specifications, compression requirements and safety measures. Low and medium pressure (<500 bar) vessels are common in industry, with low volumes of high-pressure tanks and tubes (700 – 1,000 bar) being used almost exclusively in vehicle refilling stations[92].This approach tends to be adopted for relatively small quantities or for short cycle times.

– Hydrogen can also be stored in **Bulk Underground Storage** which is suitable for the long-term storage of large quantities of hydrogen, and is widely used in the chemical and refining industries for storing natural gas. As it needs a suitable geology, with either a large cavern or a porous chamber with impermeable cap rock above (i.e. options include natural gas wells (although this can introduce contaminants, e.g., hydrogen sulphide), aquifers, and salt caverns) this restricts its widespread use for on-site storage to selected locations in the UK i.e. active hydrogen storage locations in salt caverns on Teesside, and potential sites such as in the Larne Basin[93].

Storage as a **Chemical Hydride** e.g. calcium, magnesium or lithium hydride or in sodium borohydride. These have high volumetric (comparable to LH2) and gravimetric energy densities. Hydrides are stored as a slurry with a mineral oil, effectively making them a liquid fuel which can be stored in a conventional tank. The hydrogen can be liberated by exposure to water (hydrolysis) but the reaction is highly exothermic and needs to be carefully controlled. Additionally, the regeneration process is highly endothermic, relatively inefficient and expensive as the used fuel (metal hydroxides) require high temperatures and large energy inputs, and must be returned to a central plant for regeneration. Chemical hydride storage has been demonstrated at various scales, but is typically adopted only at small scale (i.e. <100kg)

– **Storage in Metal Lattice** is another technique that is restricted to very small-scale applications. The absorption of hydrogen (hydriding) is an exothermic process and requires

[91] G Chisholm, L. Cronin, Storing Energy Chapter 16 Hydrogen from Water Electrolysis, 2016
[92] Staffell I., Scamman D., Abad A. V., Balcombe P., Dodds P.E., Ekins P., Shahd N. and Warda K.R.; The role of hydrogen and fuel cells in the global energy system, *Energy Environ. Sci.*, 2019, **12**, 463
[93] Element Energy Ltd, November 2018, Hydrogen Supply Chain Evidence Base

cooling, while the release of hydrogen (dehydriding) is endothermic and requires heating (the relevant temperature being a property of the hydride and is typically high (e.g. 300°C for magnesium hydride)) but occurs at a slow rate. Additionally, metal hydrides are very heavy, have no economies of scale in terms of weight or cost, and are sensitive to impurities. However, they have high volumetric energy densities at ambient temperatures and pressures, and are inherently safe, with no danger of catastrophic leaks or runaway reactions.

3.6 Objective 4 – Economics

Objective 4 *is to make estimates of the additional capital costs (including opportunity costs - e.g. outages whilst retrofitting) and the additional operational costs (e.g. plant machinery, increased costs of leakage monitoring, NOx abatement equipment, increased safety requirements) of converting a plant to 100% hydrogen firing.*

A concept level design using a number of representative configurations as case studies were used to produce capital and operating cost estimates for onsite assets with a clear and consistent defined basis. The intent is that the results of these case studies provide an evidence base that can be used by examiners during the application process to determine if the acceptance criteria for assessments 1 and 4, defined in Section 1.2, have been addressed appropriately by developers.

3.6.1 Basis of Estimate

The consensus across the manufacturers of power generation equipment appears to be that new, purpose-built 100%-hydrogen fired equipment cost should be similar to that for natural gas with up to approximately 10% cost difference. Current industry sentiment indicates that overall project CAPEX for new-build 100%-hydrogen fired equipment will be comparable to that for natural gas equipment. Therefore, the economic assessment in this review has considered the cost of conversion of equipment to fire hydrogen. For hypothetical new-build costs of future 100%-hydrogen power plant, it is recommended that current natural gas fired equipment cost data be used.

The capital and operating costs estimated within this review have been scaled from AECOM's internal project database for a potential retrofit conversion to 100% hydrogen firing, assuming a 'typical' scenario. No additional margin has been included to allow for especially challenging projects (e.g. lack of space for additional equipment).

For operating costs, the cost estimates have been based on the difference associated with firing 100% hydrogen compared to natural gas. For example, the fuel cost has been calculated as the difference between the cost of hydrogen and cost of natural gas, rather than the absolute cost of hydrogen fuel alone.

The methodology used for cost estimating within this review is consistent with a Class 5 level of estimate as defined by AACE International[94].

3.6.1.1 Assumptions

To determine the additional capital and operating costs that could be expected to occur with the conversion to and operation of hydrogen fired power generation several assumptions were made that are detailed below in Table 22 with a full breakdown of how these assumptions were evaluated provided in Appendix D:

[94] AACE International Recommended Practice 18R-97; Cost Estimate Classification System – As Applied in Engineering, Procurement and Construction in the Process Industries; August 2020; accessed May 2022; https://web.aacei.org/docs/default-source/toc/toc_18r-97.pdf?sfvrsn=4

Table 22 Model Assumptions

Modelling Assumption	Value	Quality	Impact	Risk Rating	Comments
Plant Availability	85%	Variable	Variable	High Potential	Typical baseload operation assumed for all scenarios to identify intrinsic differences between case studies and present data on a consistent basis. Note that lower-capacity peaking plant will affect any levelised cost calculations.
Total Installed Cost Factor	50%	Medium	Medium	Medium	Total Installed Cost Factor of 50% of total equipment cost has been assumed for all equipment. This value has been taken as an average across all equipment and comprises the subcontract costs, associated direct labour costs and materials required for installation. The value has been applied as an average to balance variation in cost to supply and install individual equipment items.
Contingency	10%	Medium	Low	Low	Contingencies of 10% were assumed for both total CAPEX and OPEX values. Whilst contingency levels assumptions will likely vary from project to project, the overall impact on results is limited.
Input Gas Composition [95]	See Appendix D	Medium	Low	Low	The input gas composition is based on the IGEM/H/1 Reference Standard for low pressure hydrogen utilisation. Whilst there is room for some variation in individual component compositions based on this specification, it is unlikely to have much impact on the final results.
Hydrogen Cost[96]	£90.4/MWh	Medium	Variable	High Potential	Value from BEIS publication. The impact of this assumption depends on the hydrogen consumption of each scenario and has a range of uncertainty due to hydrogen production itself having a range of uncertainty with technologies in various stages of development. It has been assumed that any relevant carbon price (e.g. from a blue hydrogen source) has been factored into the cost of hydrogen.

[95] IGEM, 2021, Reference Standard for low pressure hydrogen utilisation, IGEM/H/1, UK.
[96] BEIS, 2021, Hydrogen Production Costs, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1011506/Hydrogen_Production_Costs_2021.pdf

Natural Gas Cost[97]	£24.8/MWh	High	Variable	High Potential	Value from BEIS publication. The impact of this assumption depends on the hydrogen consumption of each scenario as the additional fuel cost of switching to hydrogen firing is affected by this value. The cost of natural gas at time of writing was highly volatile, however, assessment of the implications of such fluctuations is outside the scope of this review.
Conversion Costs	Variable between scenarios	Variable	Variable	High Potential	The cost of converting each case to hydrogen firing varies depending on the case. The cost of each line item for hydrogen fuel switching has been derived from a recent OEM quote for switching an existing gas turbine (similar size to the Large CHP-CCGT Case Study) to fire a blend of hydrogen. A combination of works is required for hydrogen fuel switching with a variety of associated uncertainty bands. The most uncertain part (the cost of works to the combustor and hot gas path) is offset by greater certainty in relation to other parts such as SCR, or the cost of nitrogen/water injection, if applicable.
29% Solution Ammonia Cost[98]	£791/tonne	Medium	Variable	Medium Potential	The impact of this assumption depends on the ammonia consumption of each scenario; however, the overall impact of this value is relatively minor.
CO2 Atmospheric Emissions[99]	£16.3/tonne	Medium	Variable	Medium Potential	The impact of this assumption depends on the total CO_2 emissions associated with each scenario including emissions during start-up and shut-down. For this study, it has been assumed that start-up and shut-down emissions will be negligible (for example, through either high capacity factor 0.85 as outlined above, or equipment start-up and shut-down on 100% hydrogen).
Cost year basis[100]	2022	Medium	Variable	High Potential	All costs calculated to 2022 normalised basis using BEIS deflationary index.

[97] BEIS, 2021, Greenbook supplementary guidance, https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal
[98] U.S. Environmental Protection Agency, 2016, https://www3.epa.gov/ttn/ecas/docs/SCRCostManualchapter7thEdition_2016.pdf
[99] BEIS, 2018, Updated Short-Term Traded Carbon Values Used for Modelling purposes, https://www.gov.uk/government/publications/updated-short-term-traded-carbon-values-used-for-modelling-purposes-2018
[100] BEIS, 2021, Greenbook supplementary guidance, https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

3.6.2 Capital Cost Estimate

Table 24 summaries the estimated capital cost associated with conversion of each case study to 100% hydrogen firing. The expected level of accuracy for the given maturity of estimate is provided below in Table 23. The specific costs provided are on the basis of millions of £ per MW of net thermal energy input to each case.

Table 23. Levels of accuracy assigned to data sources used for CAPEX estimation

Source	Feeds Into	Low (%)	High (%)
Scaled from project database	Equipment CAPEX (except combustion parts)	-50%	+50%
Combustion equipment Parts Scaled from project database	Combustion parts modification CAPEX	-50%	+100%
Estimating software (PEACE)	SCR CAPEX	-50%	+50%

Table 24. Capital cost estimates for the hydrogen-firing equipment in millions of £$_{2022}$

Case Study	CS1	CS2	CS3	CS4	CS5	CS6	CS7	CS8	CS9	CS10	CS11	CS12	CS13	CS14	CS15	
Type	**CCGT**	**CCGT**	**CCGT**	**CCGT**	**CCGT**	**CCGT**	**OCGT**	**OCGT**	**OCGT**	**Boiler**	**Boiler**	**Boiler**	**Recip.**	**Recip.**	**Recip.**	
MW nameplate	**220**	**450**	**805**	**14**	**35**	**60**	**2**	**4**	**290**	**10**	**65**	**120**	**1**	**12.5**	**50**	**Uncertainty**
Case Study Data																
Total thermal input (MWth LHV)	402	722.5	1307	35.7	73	116.2	7.4	13.7	764.3	31.9	159.3	353.7	2.3	27.5	112.2	
Net plant export (MWe)	218	404	805	15.4	36.1	61.1	1.8	4	301	9.5	61.7	142	1	12.3	51.3	
Net plant efficiency (%)	54%	56%	62%	43%	49%	53%	24%	29%	39%	30%	39%	40%	43%	45%	46%	
No. trains total	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**5**	**5**	
Prime Mover Modification CAPEX																
Engineering, commissioning and site services	£2.2	£3.0	£4.3	£0.8	£1.0	£1.2	£0.5	£0.7	£3.1	£0.8	£1.4	£2.2	£0.5	£3.0	£4.2	+/-50%
Combustion enclosure changes (fire, ventilation, controls, 3D scan)	£1.4	£1.8	£2.4	£0.7	£0.8	£0.9	£0.5	£0.5	£1.9	£0.2	£0.9	£1.4	£0.4	£2.5	£3.3	+/-50%
Combustion parts upgrades	£1.0	£1.4	£2.2	£0.4	£0.5	£0.5	£0.4	£0.4	£1.5	£0.1	£0.6	£1.0	£0.3	£1.9	£2.1	-50%/+100%
Fuel blending skid	£0.5	£0.7	£1.0	£0.2	£0.3	£0.3	£0.1	£0.2	£0.7	£0.2	£0.3	£0.5	£0.1	£0.7	£1.0	+/-50%
Wobbe Index meter	£1.0	£1.6	£2.9	£0.2	£0.3	£0.4	£0.1	£0.1	£1.7	£0.2	£0.5	£1.0	£0.1	£0.6	£1.1	+/-50%
Nitrogen purge skid	£0.8	£-	£-	£0.2	£-	£-	£0.1	£0.1	£-	£-	£-	£-	£-	£-	£-	+/-50%
Water injection skid	£0.8	£-	£-	£0.2	£-	£-	£0.1	£0.1	£-	£-	£-	£-	£-	£-	£-	+/-50%
Total Direct Modification Costs	**£7.7**	**£8.4**	**£12.8**	**£2.7**	**£2.9**	**£3.2**	**£1.7**	**£2.1**	**£8.9**	**£1.5**	**£3.7**	**£6.0**	**£1.4**	**£8.6**	**£11.7**	
Additional CAPEX – SCR	£1.3	£1.8	£2.2	£0.4	£0.5	£0.6	£0.1	£0.2	£1.8	£0.5	£1.9	£3.5	£0.2	£1.6	£3.1	+/-50%
Additional CAPEX – Installation of Direct Modifications and SCR	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	
Total CAPEX																
Total CAPEX	£13.5	£15.3	£22.5	£4.5	£5.0	£5.7	£2.8	£3.4	£15.9	£3.1	£8.4	£14.2	£2.4	£15.3	£22.2	
CAPEX Contingency	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	
CAPEX with Contingency	**£14.8**	**£16.8**	**£24.7**	**£5.0**	**£5.5**	**£6.3**	**£3.1**	**£3.7**	**£17.5**	£3.4	£9.3	**£15.7**	**£2.7**	**£16.8**	**£24.4**	**-50/+60%**
CAPEX low end (average -50%)	£7.4	£8.4	£12.3	£2.5	£2.8	£3.2	£1.5	£1.9	£8.7	£1.7	£4.6	£7.8	£1.3	£8.4	£12.2	
CAPEX high end (average +60%)	£23.0	£26.4	£38.8	£7.8	£8.7	£9.9	£4.9	£5.9	£27.5	£5.2	£14.4	£24.3	£4.3	£26.8	£38.4	
Hydrogen Conversion Cost Ratios																
Total thermal input (MWth LHV)	402	722.5	1307	35.7	73	116.2	7.4	13.7	764.3	31.9	159.3	353.7	2.3	27.5	112.2	
Net plant efficiency (%)	54%	56%	62%	43%	49%	53%	24%	29%	39%	30%	39%	40%	43%	45%	46%	
Total net electrical export (MWe)	218	404	805	15.4	36.1	61.1	1.8	4	301	9.5	61.7	142	1	12.3	51.3	
Total CAPEX thermal ratio (£/MWth)	**£0.037**	**£0.023**	**£0.019**	**£0.139**	**£0.076**	**£0.054**	**£0.414**	**£0.273**	**£0.023**	**£0.092**	**£0.043**	**£0.044**	**£1.165**	**£0.612**	**£0.218**	
Total CAPEX electrical ratio (£/MWe)	**£0.068**	**£0.042**	**£0.031**	**£0.323**	**£0.153**	**£0.103**	**£1.701**	**£0.935**	**£0.058**	**£0.308**	**£0.112**	**£0.110**	**£2.680**	**£1.369**	**£0.476**	

3.6.3 Operating Cost Estimate

Table 26 summarises the additional operating costs associated with each of the case studies to make them hydrogen-fired. The ranges associated with the various costs are provided in Table 25.

Table 25. Levels of accuracy assigned to data sources used for OPEX estimation

Source	Feeds into	Unit	Low	Centre	High
Hydrogen Fuel[101]	Additional Fuel Cost	£/MWh	71.0	90.4	108.5
Natural Gas[102]	Additional Fuel Cost	£/MWh	17.9	24.8	35.0
Ammonia Cost Additional	Ammonia Costs	%	-50%		+50%

[101] BEIS, 2021, Hydrogen Production Costs, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1011506/Hydrogen_Production_Costs_2021.pdf

[102] BEIS, 2021, Greenbook supplementary guidance, https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

Table 26. Additional operating cost estimates for the hydrogen-firing equipment in millions of £2022 per year

Case Study Type MW nameplate	CS1 CCGT 220	CS2 CCGT 450	CS3 CCGT 805	CS4 CCGT 14	CS5 CCGT 35	CS6 CCGT 60	CS7 OCGT 2	CS8 OCGT 4	CS9 OCGT 290	CS10 Boiler 10	CS11 Boiler 65	CS12 Boiler 120	CS13 Recip. 1	CS14 Recip. 12.5	CS15 Recip. 50	Uncertainty
Fixed Costs																
Maintenance	Assumed negligible vs natural gas															
Total Fixed OPEX	£-	£-	£-	£-	£-	£-	£-	£-	£-	£-	£-	£-	£-	£-	£-	
Variable Costs																
Additional Fuel Costs	£196.3	£352.9	£638.3	£17.4	£35.7	£56.7	£3.59	£6.67	£373.3	£15.6	£77.8	£172.8	£1.14	£13.4	£54.8	
Ammonia Costs	£5.08	£9.12	£20.49	£0.45	£0.92	£1.47	£0.09	£0.17	£9.64	£0.16	£0.83	£1.84	£0.01	£0.19	£0.90	
Total Variable OPEX	**£201.4**	**£362.0**	**£654.8**	**£17.9**	**£36.6**	**£58.2**	**£3.7**	**£6.8**	**£383.0**	**£15.8**	**£78.6**	**£174.6**	**£1.1**	**£13.6**	**£55.7**	
Total Operating Cost																
Total OPEX	**£201.4**	**£362.0**	**£654.8**	**£17.9**	**£36.6**	**£58.2**	**£3.7**	**£6.8**	**£383.0**	**£15.8**	**£78.6**	**£174.6**	**£1.1**	**£13.6**	**£55.7**	**+38%/-45%**
OPEX low end	£110.1	£197.8	£357.8	£9.8	£20.0	£31.8	£2.0	£3.7	£209.3	£8.6	£43.0	£95.5	£0.6	£7.4	£30.5	
OPEX high end	£279.0	£501.5	£907.1	£24.8	£50.7	£80.6	£5.1	£9.5	£530.5	£21.8	£108.8	£241.6	£1.6	£18.8	£77.1	
Annualised operating costs																
Capacity factor	0.85															
Operating duration	1 year															
Specific Cost (£/MWh)	**£92.08**	**£92.10**	**£92.08**	**£92.02**	**£92.14**	**£92.07**	**£91.52**	**£91.80**	**£92.09**	**£91.15**	**£91.08**	**£91.10**	**£92.21**	**£91.20**	**£91.45**	

Notes:

1. Specific Cost is provided on a £ basis instead of a millions of £ basis.
2. Specific cost is provided in terms of MWh fuel input LHV

3.6.4 Economics Summary and Discussion

The figures provided in this section have been presented on a £2022 basis using the BEIS deflationary index[103] and therefore assume the technology to convert to hydrogen is available.

3.6.4.1 Fuel switching duration

If suitable technology is available, deployment on a new site may require an implementation programme of approximately 12 months, including the mandatory outage period for works that could not be undertaken while the host facility is online. The outage may require a period from a few weeks to 3-4 months depending on the complexity of the retrofit. It is generally expected by the industry that the conversion works would be undertaken within the normal window for an extended outage.

3.6.4.2 Capital Cost

The capital costs per MW thermal input for each case study show significant variation across the case studies (from £M 0.02/MWth to £M 1.17/MWth for CS3 and CS13, respectively). The data indicates the greatest cost for the reciprocating engine case studies where the impact of converting an array of small units limits the degree of cost efficiency. The estimated capital costs have been scaled from AECOM's previous internal project data. The average level of uncertainty associated with the total capital cost estimates in this review is approximately -50%/+60% either side of the central calculated CAPEX value.

The estimated conversion costs in this review have been calculated assuming a conservative 'First-Of-A-Kind' conversion with a commensurate degree of associated project development activities (such as engineering, permitting, as well as potentially some on-site enabling works that might be expected for a typical site). It is expected that as the market matures and standardised solutions become readily available for the key hydrogen-fired power generating equipment, the associated additional costs to deliver fuel switching would reduce. An overall CAPEX reduction of up to 50% may be achievable for 'Nth-Of-A-Kind' plant once key equipment by streamlining the cost of key equipment optimising the Given the factored methods for calculating cost estimates in this review, it seems plausible that an overall CAPEX reduction of up to 50% may be achievable for 'Nth-Of-A-Kind' plant.

3.6.4.3 Operating Cost

For all the case studies, the additional operating cost estimate was calculated as approximately £91-92 per MWh of net heat input above the natural gas baseline. This estimate comprises the variable fuel and SCR reagent costs. It has been assumed within this review that the difference to fixed costs such as maintenance and operations would be negligible following conversion to hydrogen.

The operating cost value calculated within this review is particularly sensitive to the cost of the input fuel which comprises approximately 90-95% of the calculated OPEX figure. Therefore, projects exposed to future wholesale hydrogen pricing (such as those seeking to utilise blue hydrogen from a centralised supply network) will be particularly vulnerable to price fluctuations and will likely seek to purchase their fuel during periods of relatively low cost wherever possible.

[103] BEIS, 2021, Greenbook supplementary guidance Table 19, https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

3.7 Objective 5 – Development of Hydrogen Readiness

***Objective 5** is to estimate the dates by which combustion technologies that can fire increasing blends of hydrogen (e.g. 20%, 50%, 100%) will be available from manufacturers.*

The following section reviews the current state of the art in terms of operational equipment as well as the OEM's published capability and current offerings. The section also reviews the technical barriers to full hydrogen firing, the development programs on-going with OEMs and likely development pathway.

3.7.1 Combustion of synthesis gas

There is a significant body of experience in combustion of 'low BTU' gases in gas turbines. Combustion of synthesis gas (or syngas) is commonly undertaken in industrial applications. Syngas comprises a hydrogen-rich fuel mixed with varying quantities of diluents such as carbon monoxide and/or carbon dioxide; syngas is the primary product of the first stage of methane reforming, see Section 3.5.1.1 for a general overview of syngas production as part of methane reforming.

The composition of syngas fuel varies depending on the feedstock and therefore between different sites. However, some general conclusions in relation to the combustion of syngas in comparison to a blended fuel of natural gas are presented below:

- Syngas heating value is generally lower than natural gas or natural gas/hydrogen blends, posing different combustor design challenges due to the different dilution properties of CO compared to CO_2 or N_2.
- The CO present in syngas has an impact on NO_X formation which is not fully understood across the full range of CO fractions[104].

Syngas combustion has been frequently cited by OEMs as part of the development pathway for achieving 100% hydrogen combustion in air through adaptation of syngas combustion technology.

3.7.2 Gas Turbines

3.7.2.1 Operating Plants

Table 28 summarises the literature review of operational gas turbines in hydrogen service. This list is not exhaustive.

3.7.2.2 OEM Current Capability

The following section reviews the current capability of each of the major OEMs.

[104] Afzanizam Samiran, Nor, Samiran, Jo-Han, Nazri Mohd Jafar, Mohammad, Valera Medina, Agustin and Chong, Cheng Tung 2016. H2-rich syngas strategy to reduce NOx and CO emissions and improve stability limits under premixed swirl combustion mode. International Journal of Hydrogen Energy 41 (42) , pp. 19243-19255.

3.7.2.2.1 Ansaldo Energia

Ansaldo Energia claim that their gas turbines are capable of burning hydrogen-natural gas blends to the maximum concentrations shown in Table 27 They also claim that they can “comfortably handle intermittent or fluctuating H_2 supply maintaining full adherence to NOx emission requirements”.

Table 27 Ansaldo Energia Existing Hydrogen Capability

Technology	Application in Gas Turbine†	Maximum Hydrogen Capability (vol %)	NOx Emissions (ppmv @ 15% O_2, dry gas)
Sequential Combustion	GT36 New and service	70	15
Sequential Combustion	GT26 New and service	45	15
Single Stage Combustion	AE94.3A New and service††	25	25
Single Stage Combustion	AE94.2 New and service††	25	25

† No hardware modification on gas turbine

†† Including V94.3A/V94.2 technology

Ansaldo Energia have a stated aim of achieving a target of firing their single stage combustion gas turbines with a mixed blend of 40 vol% hydrogen (CO_2 reduction of ~17% (see Figure 2)) by 2023. Progress towards this target started in 2006 with two AE94.3A, being capable of burning a blend of natural gas and 15 vol% H_2 (CO_2 reduction of ~5% (see Figure 2)), using standard hardware and an unmodified fuel system. This composition has been extended in phases to burning 18 vol% H_2 (CO_2 reduction of ~6% (see Figure 2)) in 2010 and to the current 25 vol% (CO_2 reduction of ~9% (see Figure 2)) in 2017[105].

Ansaldo have announced a development partnership with Equinor to develop and test 100% hydrogen capability for their GT36 and GT26 technology[106]. Ansaldo have stated an aspiration to roll this technology out across their portfolio by 2030[107].

3.7.2.2.2 Siemens Energy

Siemens Energy claim that all their gas turbines can already operate on hydrogen fuel with the specific capability being determined by the gas turbine model and the type of combustion system (see Figure 15[108]). As illustrated by Figure 15 some of the small and medium gas turbines can burn up to 60 vol% H_2 (CO_2 reduction of ~30% (see Figure 2)) whilst the larger units are limited to 30 vol% (CO_2 reduction of ~11% (see Figure 2)).

[105] https://www.ansaldoenergia.com/business-lines/hydrogen-for-the-energy-transition/hydrogen-solutions
[106] Ansaldo Energia, Ansaldo Energia and Equinor collaborate on validation of 100% hydrogen gas turbine combustor, October 2019, accessed May 2022, https://www.ansaldoenergia.com/Pages/Ansaldo-Energia-and-Equinor-collaborate-on-validation-of-100-hydrogen-gas-turbine-combustor.aspx
[107] Gas Turbine World, Ansaldo Energia Hydrogen Gas Turbines, September 2021, accessed May 2022, https://gasturbineworld.com/ansaldo-hydrogen-gas-turbines/
[108] White paper, Hydrogen power with Siemens gas turbines, April 2020

Table 28 Summary of Commercial Gas Turbines Tested with High Hydrogen Content Fuels[109]

Power	Model	Company	Fuel	CO_2 Reduction	Emissions	Maturity	Features
30 MW_e	L30A-01D/DLH	Kawasaki	≤60 vol% H_2	~30%	NO_x < 25 ppm	Commercial	DLE pre-mixed combustor; eight can combustor; highest electrical efficiency in its class
200 MW_e	GT13E2	General Electric	≤45 vol% H_2	~20%	NO_x 20 - 25 ppm	Test	Annular combustor; partially pre-mixed operation; N2 dilution up to 55 vol%; E-class
250 MW_e	GT24, 60Hz	Ansaldo Energia	≤70 vol% H_2	~40%	NO_x < 25 ppm	Test	Two lean pre-mixed DLE annular combustors; F-class
11.25 MW_e	GE10 (PGT10)	General Electric	≤100 vol% H_2	~100%	NO_x < 25 ppm	Commercial	Diffusion system or DLE system; silo-type single-can combustor; steam injection for NO_x reduction
40 MW_e	MS6001B	General Electric	95 vol% H_2	~85%	DLE NO_x ≈ 25 ppm (natural gas)	Commercial	10 cannular combustors; steam or water injection; can be fitted with DLE
211 MW_e for GE7FA	Flamesheet	Power Systems Mfg	≤60 vol% H_2	~30%	NO_x < 10 ppm	Commercial	Cannular, fully pre-mixed combustor; staged operation; trapped vortex stabilization; 30% modified Wobbe index range; E- and F-class
120 - 206 MW_e	TG50 DLN	Ethos Energy (UK)	100 vol% H_2	~100%	NO_x < 25 ppm	Prototype Tests	Cross flow fuel injection system modified to co-flow axial swirler
170 MW_e	V94.2K, 50Hz	Ansaldo Energia	≤45 vol% H_2	~20%		Test	Diffusion system; two silo-type combustors; steam dilution up to 50 vol%; E-class
230 MW_e	SGT6-5000F, 60Hz	Siemens	~45 vol% H_2	~20%	NO_x < 15 ppm	Test	Two-stage diffusion flame combustor; N_2 and/or steam dilution; F-class; catalytic combustion developed

[109] Du Toit M.H., Avdeenkov A.V., Bessarabov D.; Reviewing H2 Combustion: A Case Study for Non-Fuel-Cell Power Systems and Safety in Passive Autocatalytic Recombiners, Energy Fuels 2018, 32, 6401−6422

Power	Model	Company	Fuel	CO_2 Reduction	Emissions	Maturity	Features
7 MW_e	SGT-200, 50/60Hz	Siemens	80 - 85 vol% H_2	~55 – 63%	$NO_x \leq 25$ ppm	Commercial	DLE combustion system; cannular combustor; eight reverse flow tubular combustion chambers
15 MW_e	SGT-400	Siemens	30 vol% H_2 stable, >70 vol% needs redesign	~11%	~5 times higher than reference conditions	Test	Can combustor; pilot and main burner; DLE combustion system; radial air swirler
24.77 MW_e	SGT-600, 50/60 Hz	Siemens	20 - 90 vol% H_2	~7 – 73%	$NO_x \leq 225$ ppm with conventional fuel	Commercial	Second generation DLE; third generation DLE; Non-DLE
121 MW_e single, 173 MW_e combined	SGT6-3000E, 50Hz	Siemens	40 - 60 vol% H_2/ 100 vol% syngas	~17 – 30%	Single digit NO_x for RCL with conventional fuel	Commercial	14 can combustors in a circular array; steam dilution ≤ 22 vol% or $N_2 \leq 30$ vol%; catalytic combustion tested; E-class

Note: The concentration of H_2 in the syngas can vary between different studies

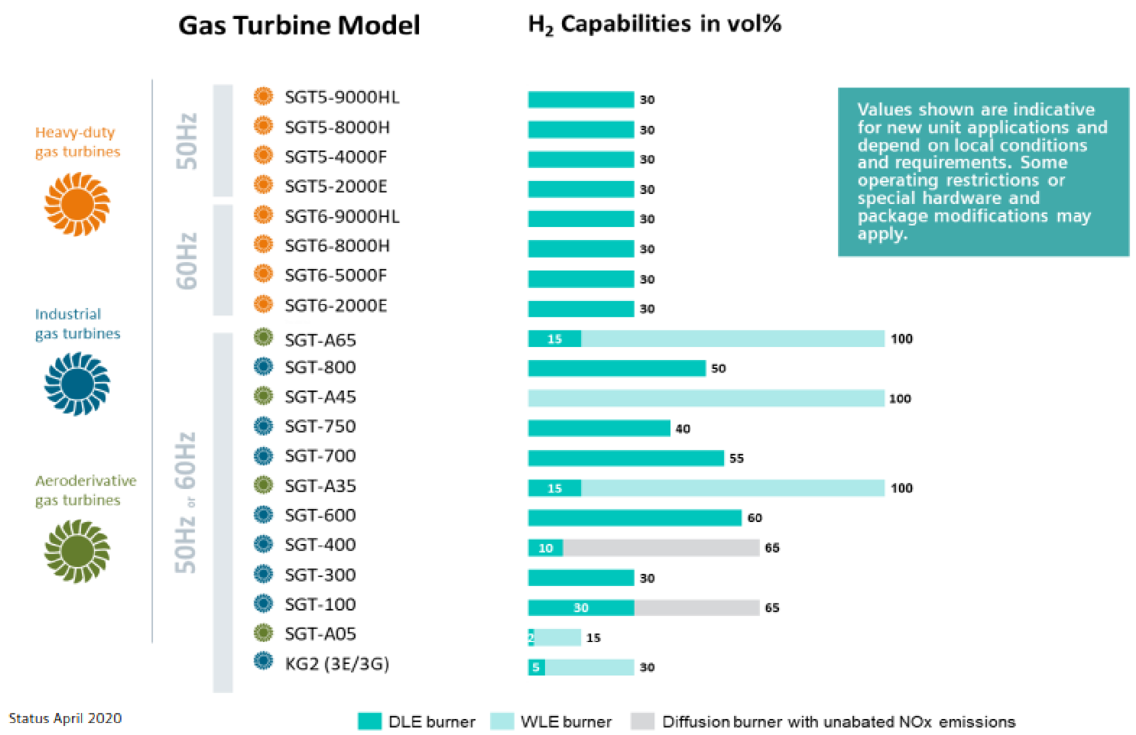


Figure 15 Siemens Gas Turbine Portfolio Hydrogen Capability (new unit applications)

Siemens Energy's roadmap is to develop gas turbines with DLE capable of running on 100% H_2 (CO_2 reduction of ~100% (see Figure 2)) by 2030[110]. Testing has been successfully undertaken on a variant of the 3rd generation DLE burner, that is used in the SGT-600, SGT-700 and SGT-800, using up to 100% hydrogen fuel at engine-like conditions[111].

Siemens Energy have aeroderivative gas turbines with Wet Low Emissions (WLE) combustion systems that are capable of operating on 100% hydrogen now.

Siemens Energy has gained non-DLE experience with high-hydrogen fuels on SGT-500 and SGT-600 industrial gas turbines burning refinery fuel gases with up to 90 vol% hydrogen content(CO_2 reduction of ~73% (see Figure 2)).

The SGT-200 has refinery gas experience of more than 800,000 operating hours with a composition containing up to 85 vol% hydrogen (CO_2 reduction of ~63% (see Figure 2)).

Examples of other high hydrogen operation are listed below:

- Leipzig Süd district heating power plant: Two SGT-800 gas turbine packages with electrical and thermal capacities of approximately 125 MW and 163 MW respectively. The plant is expected to operate with 30 to 50 percent hydrogen (CO_2 reduction of ~11 - 23% (see Figure 2)) after a few years following commercial operation with the long-term objective of operating on 100% hydrogen. Commissioning with natural gas is scheduled for the end of 2022. Followed by increasing proportions of hydrogen[112].
- 10 MW SGT-400. A commercial dry low emissions unit is being modified to operate initially in 2021 on a hydrogen and natural gas fuel blend with an incremental build up to 100% hydrogen.
- 24 MW SGT-600. Two DLE gas turbines tested in 2019 on mixtures of up to 60% hydrogen by volume (CO_2 reduction of ~30% (see Figure 2)) while maintaining 25 ppm NOx emissions are expected to begin commercial operation in 2021.

[110] J. Isles, Flexing the power of Hydrogen, The Energy Industry Times, October 2020, Volume 13, No 6
[111] White paper, Hydrogen power with Siemens gas turbines, April 2020
[112] Press Release, Munich, November 19, 2020 Gas turbines from Siemens Energy are providing Leipzig with a climate neutral power supply, https://bit.ly/3nzEO2S

– 33 MW SGT-700. Developmental hydrogen burner design based on additive manufacturing technology was tested on 100% hydrogen in 2019 while maintaining fairly low NOx emissions.

– 48 MW SGT-800. Full engine sector testing in 2020 with a hydrogen-fed array of 5 burners (out of 30 burners) operating on 75% by volume hydrogen (CO_2 reduction of ~48% (see Figure 2)) and 40 ppm NOx emissions.[113]

3.7.2.2.3 Mitsubishi Hitachi Power Systems

Mitsubishi Hitachi Power Systems' (MHPS) progress towards 100 vol% hydrogen (CO_2 reduction of ~100% (see Figure 2)) operated units is illustrated in Figure 16. This shows that, while their diffusion combustor appears to be capable of achieving 100 vol% hydrogen (CO_2 reduction of ~100% (see Figure 2)), their DLN technology is currently at approximately 30 vol%.

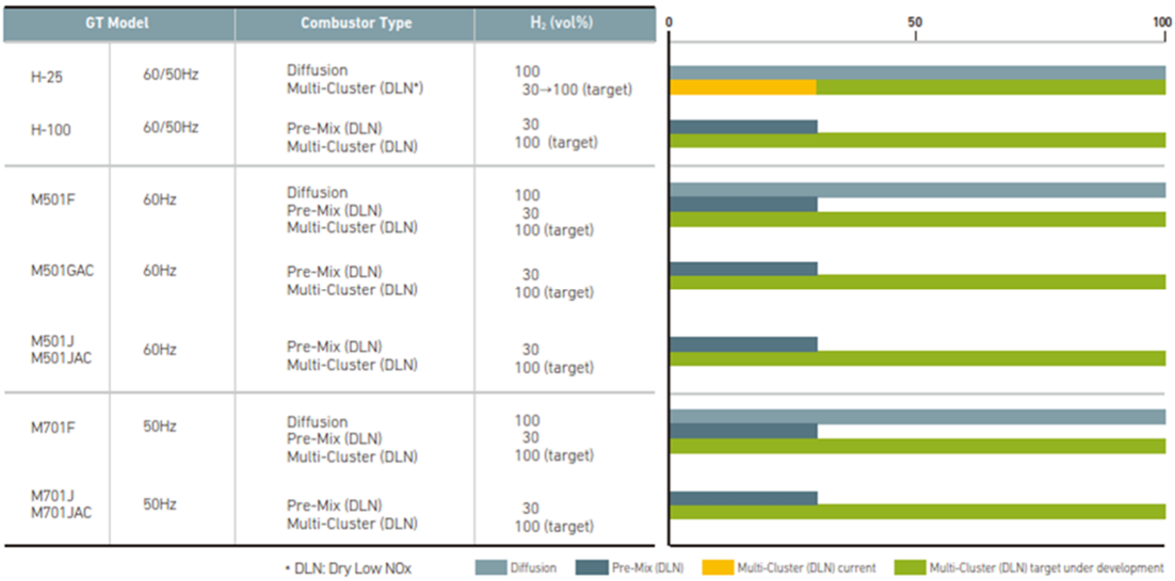


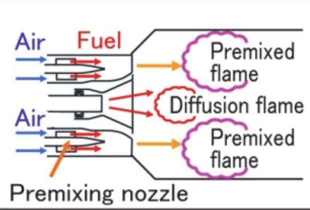
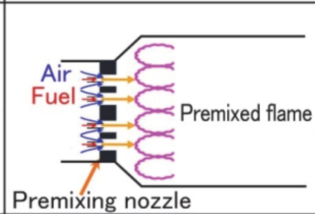
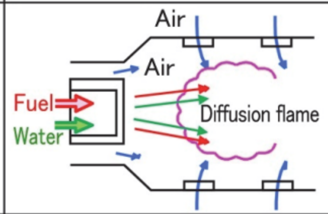
Figure 16 MHPS Gas Turbine Hydrogen Capability

In 2018, MHPS successfully developed a burner that was able to use a blend of 30 vol% hydrogen with natural gas (CO_2 reduction of ~11% (see Figure 2)) while maintaining NOx emissions at conventional levels, operating without flashback and minimising the increase in combustion pressure fluctuations. [114]

After successfully demonstrating 30 vol% co-firing, MHPS is moving into the next phase of its program to achieve gas turbines running on 100 vol% hydrogen. This is being based on Dry Low NOx (DLN) hydrogen combustor technology. MHPS' approach is through the development of a multiple injection burner i.e. a "multi-cluster combustor", which adopts fast mixing due to numerous small fuel nozzles that create smaller sprays being released in a high velocity region within the combustor. This reduces the likelihood of a flame travelling up the fuel's flow path and damaging the nozzles. MHPS has targeted completing its rig test of 100% hydrogen firing at its facility in Takasago, Japan by 2025. The development status of MHPS' combustors for hydrogen-fired gas turbines are illustrated in Table 29[115].

[113] J. Isles, H. Jaeger, Accelerating the technology roadmap for decarbonizing gas turbines via hydrogen fuel, Gas Turbine World, December 2020, www.gasturbineworld.com
[114] Initiatives in the Hydrogen Supply Chain Aimed at Realizing a Carbon-Free Society, MHI Report 2019
[115] MASAKAZU NOSE, TOMO KAWAKAMI, HIDEFUMI ARAKI, NORIAKI SENBA, SATOSHI TANIMURA, Hydrogen-fired Gas Turbine Targeting Realization of CO2-free Society, Mitsubishi Heavy Industries Technical Review Vol. 55 No. 4 (December 2018)

Table 29 MHPS Combustors for Hydrogen Gas Turbines

Combustor	Multi-nozzle combustor	Multi-cluster combustor	Diffusion combustor
Combustion method	Premixed flame combustion	Premixed flame combustion	Diffusion flame combustion
Structure			
NOx	Low NOx due to flame temperature uniformed by premixing nozzle	Low NOx due to flame temperature uniformed by small premixing nozzle	Fuel is injected in to air. There is a high-flame temperature region and the NOx is high
Flashback	High flashback risk in the case of hydrogen mono-firing because of the large flame propagating area	Low flashback risk due to the narrow flame propagating area	No flashback risk because of diffusion flame
Cycle efficiency	No efficiency drop due to no steam or water injection	No efficiency drop due to no steam or water injection	Efficiency drop occurs because steam or water are injected to reduce NOx
Hydrogen co-firing ratio	Up to 30 vol%	Up to 100 vol% (under development)	Up to 100 vol%

MHPS is now working with Vattenfall AB to deploy their technology at the Magnum Power Plant in the Netherlands. This project aims to convert one of the three existing generation units, which house M701F gas turbines (440MW/unit), to be 100% hydrogen-firing by 2025[116].

Following the development of the multi-cluster combustor and testing at Vattenfall, MHPS current aspirations are to deliver the first commercial 100% hydrogen gas turbines with the multi-cluster combustor DLN technology before 2030.

Estimates for hydrogen consumption requirements of MHPS' gas turbine technology are presented in Table 30[117]

Table 30 Fuel Consumption by Gas Turbine Model

Turbine Type	ISO Base Rating (kW)†	Efficiency	Hydrogen††		Natural Gas	
		(% LHV)	(t/h)	(Nm^3/h)	(t/h)	(Nm^3/h)
H-25	41,030	36.2	4	45,000	9	12,000
H-100	116,450	38.3	10	112,000	24	30,000
M701F	385,000	41.9	28	312,000	72	90,000
M701J	478,000	42.3	34	379,000	88	110,000
M701JAC	448,000	44.0	31	345,000	79	99,000
M701JAC	574,000	43.4	40	445,000	103	128,000

† Atmospheric temperature 15°C base (ISO standard)

†† Fuel Consumption when 100% hydrogen fired is estimated based on the performance of a natural gas-fired system

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3.7.2.2.4 General Electric

General Electric (GE) offer combustion systems on more than 70 models within their Aeroderivative and Heavy Duty gas turbines that can operate with blends of hydrogen ranging from 5 vol% to 100 vol% (CO_2 reduction of ~2 - 100% (see Figure 2)). This includes approximately 28 gas turbines that are operating on fuel blends containing >45 vol% hydrogen[118] (CO_2 reduction of ~20% (see Figure 2)).

- GE's Aeroderivative gas turbines can be configured with a single annular combustor (SAC), which can handle hydrogen concentrations from 30% (by volume) up to 85% (by volume) (CO_2 reduction of ~11 - 63% (see Figure 2)) depending on the specific model.
  - Single Nozzle (SN) or standard combustor are supplied on B and E-class turbines with the Multi-Nozzle Quiet Combustor (MNQC) being available on multiple E and F-class gas turbines. GE is currently quoting that these combustors can handle up to ~90-100 vol% (CO_2 reduction of ~73 - 100% (see Figure 2)).
  - GE's Dry Low Emission (DLE) combustion system hasis limited to 5 vol% hydrogen (CO_2 reduction of ~2% (see Figure 2)) and the Dry Low NOx (DLN) combustion systems are capable of operating with up to 33 vol% hydrogen (in the DLN1 which is available on GE's 6B, 7E, and 9E gas turbines) (CO_2 reduction of ~13% (see Figure 2)) .
  - The DLN 2.6+ combustion systems are capable of operating on hydrogen levels up to ~15 vol% (CO_2 reduction of ~5% (see Figure 2)). However, to operate at high hydrogen compositions would require the fuel systems to be upgraded as they are currently only configured for a maximum of 5 vol% hydrogen (CO_2 reduction of ~2% (see Figure 2)).
  - The state-of-the-art DLN 2.6e systems (such as those fitted to 7HA and 9HA) have a stated capability up to 50%, with GE undertaking development to increase the blending limit.

GE have been part of the US Department of Energy's Advanced IGCC/Hydrogen Gas Turbine program. As a result, they have developed a low-NOx hydrogen combustion system based on small scale jet-in-crossflow mixing of the fuel and air streams. This technology is a function of the DLN 2.6e combustion system, which is available on the 9HA gas turbine and has been demonstrated on fuel blends containing 50 vol% hydrogen in preliminary testing[119].

Examples of GE's experience of hydrogen blended fuels are provided below:

- The Dow Plaquemine plant, USA. Here hydrogen is injected into natural gas to create a 5% / 95% (by volume) blend of hydrogen and natural gas (CO_2 reduction of ~2% (see Figure 2)) which is fed into four GE 7FA gas turbines configured with DLN 2.6 combustion systems. Operation started in 2010.
- Gibraltar-San Roque refinery. Refinery fuel gas (RFG) containing a variable amount of hydrogen is fed to a 6B.03 gas turbine. This plant operates by blending natural gas with the RFG if the hydrogen level exceeds ~32 vol% (CO_2 reduction of ~12% (see Figure 2)).
- GE has multiple heavy-duty and gas turbines operating on low calorific value by-product gases with varying concentrations of hydrogen fuels, such as blast furnace gas (BFG) and coke oven gas (COG). Examples include multiple steel mills in Asia using COG / BFG fuel blends in GE 9E.03 gas turbines. GE's Aeroderivative can also operate on COG, for example a set of LM2500+ turbines commissioned in 2011 operate on COG with approximately 60% (by volume) hydrogen (CO_2 reduction of ~30% (see Figure 2)).
- Syngas from gasification with a hydrogen content of between 20 vol% and 50 vol% (depending on feedstock and gasification process) are being used in multiple IGCC (integrated gasification combined cycle) plants with E-class and F-class gas turbines are in commercial operation globally e.g. the Tampa Electric Polk Power Station, the Duke Edwardsport IGCC plant, and the Korea Western Power (KOWEPO) TaeAn IGCC plant.

[118] Du Toit M.H., Avdeenkov A.V., Bessarabov D.; Reviewing H2 Combustion: A Case Study for Non-Fuel-Cell Power Systems and Safety in Passive Autocatalytic Recombiners, Energy Fuels 2018, 32, 6401−6422

[119] Dr J Goldmeer, February 2019, POWER TO GAS: HYDROGEN FOR POWER GENERATION; Fuel Flexible Gas Turbines as Enablers for a Low or Reduced Carbon Energy Ecosystem, GE Power, GEA33861
Available at: https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861%20-%20Fuel%20Flexible%20Gas%20Turbines%20as%20Enablers%20for%20a%20Low%20Carbon%20Energy%20Ecosystem.pdf Accessed 17th February 2022

– GE's fleet of gas turbines installed for operation on high hydrogen fuels includes more than a dozen Frame 5 gas turbines and more than 20 6B.03 gas turbines. Many of these turbines operated on fuels with hydrogen concentrations ranging from 50% (by volume) to 80% (by volume) (CO_2 reduction of ~23 - 55% (see Figure 2)). One example of a gas turbine operating on a high hydrogen fuel is a 6B.03 at the Daesan refinery in South Korea. This unit has operated on a fuel containing more than 70 vol% hydrogen for over 20 years with a maximum level at 97 vol% (CO_2 reduction of ~91% (see Figure 2)) (although its performance was reduced)[120]. To date the unit has accumulated more than 100,000 hours on the high hydrogen fuel.

– GE produced the first gas turbine capable of operating on 100 vol% hydrogen in collaboration with Enel at Fusina, Italy. This plant, which was inaugurated in 2010, used a GE-10 gas turbine to produce ~11.4 MW of net electrical power operating on a fuel that was ~97.5% (by volume) hydrogen (CO_2 reduction of ~92% (see Figure 2)).[121]

See below Figure 17 for a summary of GE's current capabilities and future aspirations.

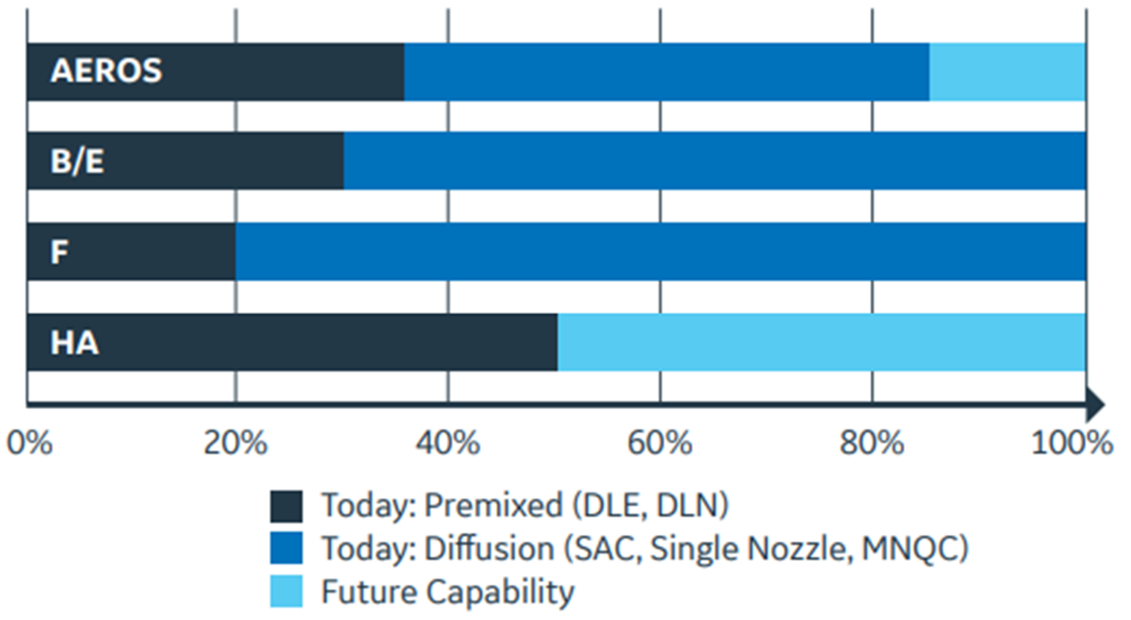

Figure 17. GE gas turbine blend levels of hydrogen (by volume)[122]

3.7.2.2.5 Kawasaki Heavy Industries

Kawasaki are currently designing gas turbines and combustion systems to handle natural gas and hydrogen blends and have a commercial gas turbine (model L30A01D) that can run on 60 vol% H_2 (CO_2 reduction of ~30% (see Figure 2)) , with very low NOx emissions.

In 2015, Kawasaki Heavy Industries announced that they had developed a low NOx emission hydrogen-fuelled gas turbine system based on DLE combustion technology. This technology was tested on 100

[120] Du Toit M.H., Avdeenkov A.V., Bessarabov D.; Reviewing H2 Combustion: A Case Study for Non-Fuel-Cell Power Systems and Safety in Passive Autocatalytic Recombiners, Energy Fuels 2018, 32, 6401−6422
[121] Dr J Goldmeer, February 2019, POWER TO GAS: HYDROGEN FOR POWER GENERATION; Fuel Flexible Gas Turbines as Enablers for a Low or Reduced Carbon Energy Ecosystem, GE Power, GEA33861
Available at: https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861%20-%20Fuel%20Flexible%20Gas%20Turbines%20as%20Enablers%20for%20a%20Low%20Carbon%20Energy%20Ecosystem.pdf Accessed 17th February 2022
[122] GE hydrogen overview, GE Power, accessed May 2022, available online at: https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/future-of-energy/hydrogen-overview.pdf

vol% H_2 at high temperatures and pressures and achieved <40 ppm NOx emissions (compared to the limit of 84 ppm (at 15% O_2))[123].

KHI have stated the ambition to achieve 100% hydrogen blending for their diffusion units by the mid-2020s, followed by their Micromix combustor units using dry low emissions technologies by 2030 to meet the targets of the Hydrogen Growth Strategy in Japan, see Figure 18[124].

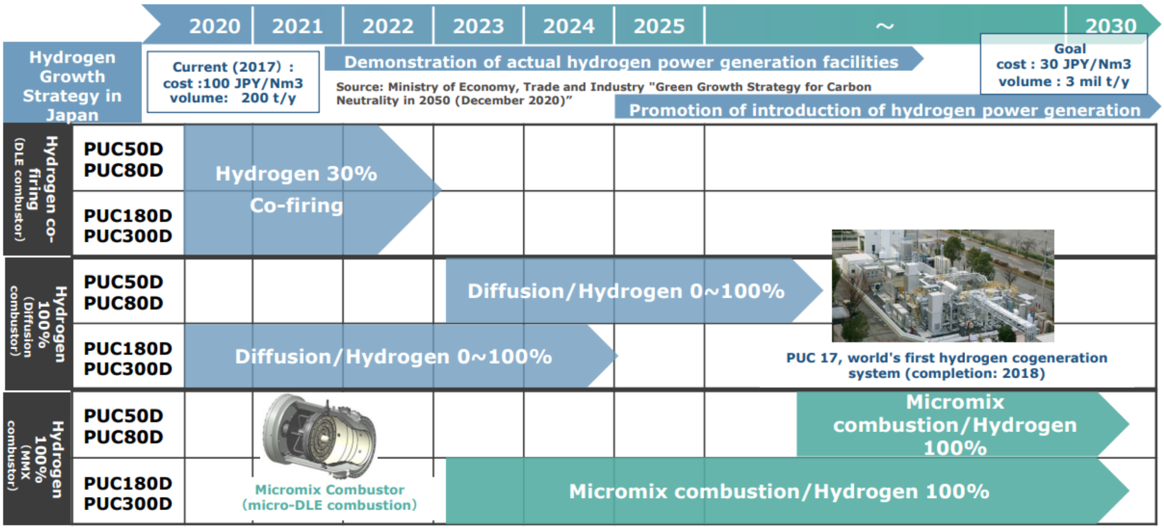

Figure 18. KHI roadmap for hydrogen combustion in gas turbines

3.7.2.2.6 Aurelia Gas Turbines

Aurelia manufacture a 400kW gas unit that is containerised (A400) and uses a canned combustor. In response to the OEM consultation, Aurelia have stated their development programme has targets to achieve up to 50vol% blending by 2023, up to 70% by 2023/24, and up to 100% in 2024/25. Note that the development programme is dependent on external investment, see Appendix 0.

[123] Du Toit M.H., Avdeenkov A.V., Bessarabov D.; Reviewing H2 Combustion: A Case Study for Non-Fuel-Cell Power Systems and Safety in Passive Autocatalytic Recombiners, Energy Fuels 2018, 32, 6401−6422
[124] Kawasaki Heavy Industries Ltd, Toward the Realization of a Hydrogen Society, June 2021, accessed May 2022, available online: https://global.kawasaki.com/en/energy/pdf/20210713_Toward%20the%20Realization%20of%20a%20Hydrogen%20Society.pdf

3.7.2.3 Technical development barriers

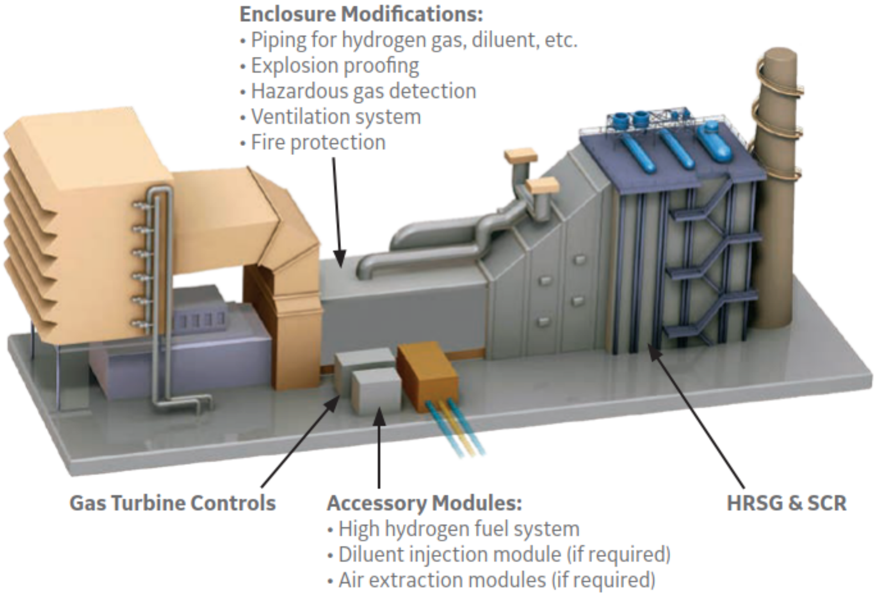

Figure 19 Potential Impact of Hydrogen Fuel Conversion on Gas Turbine Systems[125]

The following section details the technical development barriers for increasing the percentage of hydrogen in fuel gas for gas turbines. Due to the nature of hydrogen, its fundamental combustion properties such as heat of combustion, flame speed, burning velocity, flammability limits, ignition delay time and flame temperature, are very different to that of methane. The following issues describe the potential challenges that the combustion properties of hydrogen differ from that of methane[126].

- Flashback: This occurs when the fuel flow speed becomes slower than the laminar burning velocity. This causes the flame to propagate upstream damaging the fuel injectors. Due to hydrogen's high burning velocity the potential for flashback is increased and the addition of hydrogen to fuels increases the risk for flashback. Flashback can be avoided by increasing the burner exit velocity by increasing the fuel flow; however, relying on maintaining high burner exit velocity would impose its own challenges during start, stop and other transient conditions.
- Blow-off: This occurs when the flow velocity exceeds the laminar burning velocity to the extent that the flame detaches from the burner rim and propagates at a distance from the burner. Blending hydrogen reduces the risk of blow-off.
- Burning Velocity: This is "the velocity that unburned gases move through the combustion wave". Hydrogen has high burning rates which can result in the combustion of hydrogen in gas turbines becoming unstable.
- Ignition Delay: This identifies the time required for pre-mixing before self-ignition and combustion occur. Excessive time for pre-mixing introduces a risk that the fuel can self-ignite and damage equipment. This is a particular issue for compounds like hydrogen which is very reactive with a low self-ignition energy. Increasing the concentration of hydrogen in a fuel blend decreases the ignition delay time.
- Emissions: NOx in the form of NO is temperature dependant with very high production rates occurring at >1800 K and is also dependant on the square root of pressure. Reduction of the flame temperature or reducing the time in the combustion chamber can reduce the quantity of NOx emissions produced.

[125] Dr J Goldmeer, February 2019, POWER TO GAS: HYDROGEN FOR POWER GENERATION; Fuel Flexible Gas Turbines as Enablers for a Low or Reduced Carbon Energy Ecosystem, GE Power, GEA33861
Available at: https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861%20-%20Fuel%20Flexible%20Gas%20Turbines%20as%20Enablers%20for%20a%20Low%20Carbon%20Energy%20Ecosystem.pdf Accessed 17th February 2022
[126] Du Toit M.H., Avdeenkov A.V., Bessarabov D.; Reviewing H2 Combustion: A Case Study for Non-Fuel-Cell Power Systems and Safety in Passive Autocatalytic Recombiners, Energy Fuels 2018, 32, 6401−6422

Changes to thermoacoustic noise patterns because of the different flame heat release distribution can reduce the life of combustion system components[127]For the combustion of hydrogen, the combustor is the key item that requires modification. The combustor technologies currently being explored by OEM's include diffusion, pre-mixed, multiple injection, catalytic, altered oxygen concentration, staged, and trapped vortex combustion. Each of these are discussed below:

Diffusion Combustion

Diffusion Combustion (non-pre-mixed) where air and fuel are independently injected into the combustion chamber and subsequently mixed by turbulent diffusion is the most commonly used process. These tend to be more stable than pre-mixed combustion systems and can be used with hydrogen blends.

Most gas turbines that burn hydrogen use this type of combustor, but this results in a three-fold increase in the production of NOx emissions compared to natural gas. NOx emissions tend to be reduced through the addition of diluents such as steam or nitrogen, which decrease the combustion temperature (resulting in lower NOx emissions). Fuel dilution lengthens the ignition delay times and reduces the turbulent burning rates, but very large quantities of diluents are required (~50 vol%), resulting in increased complexity of the overall system and increases costs. The adoption of steam also requires additional power, which reduces the efficiency of the overall system.

Pre-mixed Combustion

In this process the fuel and air are pre-mixed before they enter the combustion chamber. This can reduce NOx emissions but increases the risk of Flashback, pre-ignition and blowout. These risks are increased when using hydrogen or hydrogen blend fuels. Examples of the technology being investigated by OEM's is Dry Low NOx emission combustion (DLE, dry low emission, DLN or dry low NOx), see below for

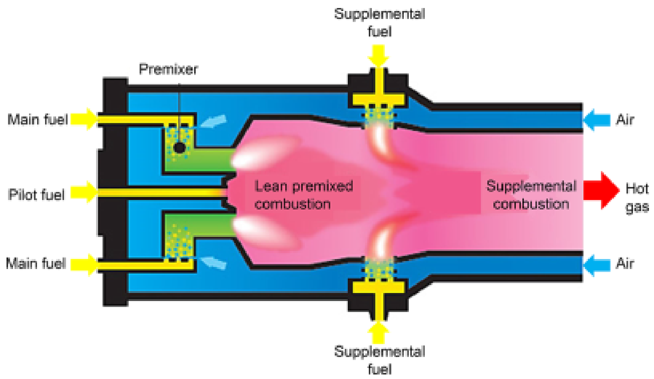

Figure 20 Pre mixed DLE/DLN combustion[128]

This technology has issues with combustion instabilities due to fluctuations caused by unsteady flow or oscillations in equivalence ratio resulting in the potential generation of large pressure waves that affect the heat release field. These heat release fluctuations contribute to thermo-acoustic instabilities, which results in increasing the pressure.

Flame stability, created by recirculation regions, is an important consideration in combustion. It can be created by a variety of techniques, with swirl stabilization being the most effective and commonly adopted. In this technique the swirl flow entrains and recirculates hot combustion products back to the flame core. This breaks down the vortex and establishes two recirculation zones: a central zone and an outer recirculation zone near the burner walls.

Although pre-mixed swirl-stabilized combustion has potential issues with thermo-acoustic instabilities, flashback, and fuel composition sensitivity it has been demonstrated that as the swirl number is

[127] White paper | Hydrogen power with Siemens gas turbines | April 2020
[128] Du Toit M.H., Avdeenkov A.V., Bessarabov D.; Reviewing H2 Combustion: A Case Study for Non-Fuel-Cell Power Systems and Safety in Passive Autocatalytic Recombiners, Energy Fuels 2018, 32, 6401−6422

increased, blow-off reduces and flashback is improves; therefore a high swirl number is desired for H2 fuels[129].

Staged Combustion

This divides the combustion chamber into multiple regions of equivalence ratio, resulting in stoichiometric conditions being avoided and so reducing NO emissions.

The COSTAIR method achieves stable combustion and low emissions by using internal recirculation and continuously staged air. Air is continually discharged through a distributor tube with multiple holes. The fuel enters by numerous jets arranged around the air distributor. The homogeneous release of heat through the combustion chamber, reduces hotspots and NO emissions.

Rich-burn quick-quench lean-burn (RQL) is a staged combustion method where the conditions begin as rich in the primary zone before moving to lean conditions following the addition and mixing of air downstream of the combustor. Combustion stability is improved in the rich-burn section due to the production of large amounts of H_2. The gases exiting this section contain large amounts of partially oxidized and pyrolyzed fuels, and CO. By adopting an equivalence ratio of the fuel-rich zone in the range 1.2−1.6 and of the lean-burn zone in the range 0.5−0.7 NOx and CO emissions can be reduced. RQL combustion can burn fuels of variable composition, but it requires more hardware, increasing system complexity and incurring higher cost.

Vortex Stabilized Combustion

Trapped vortex combustion (TVC) is a technique where vortices are used to stabilize the flame. It is a technology that has the potential to reduce NOx emissions, reduce combustor pressure drop, and enhance flame stability. In this technology a bluff body is positioned upstream of a smaller bluff body, causing vortices to become trapped in the space between the two bodies. Depending on the size and distance between the bluff bodies, a recirculation zone is created in the cavity with a stable trapped vortex.

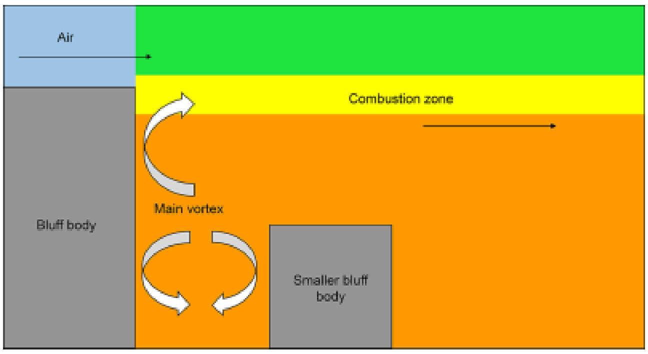

Figure 21 Trapped Vortex Combustion[130]

The FlameSheet combustor uses trapped vortices and the GT24 and GT26 gas turbines use vortex generators (see Table 28).

Multiple Injection Combustion

The adoption of multiple fuel injectors can reduce NO emissions by improving hydrogen and air mixing which reduces the environment where layers of high-temperature stoichiometric mixtures can form. Concepts which are included in this category include: Lean Direct Injection (LDI), multi-injection, micro-mixing, and multi-tube mixing all are approaches where the reactants are injected into the combustor via multiple small jets. These technologies help to reduce flashback and NOx formation

[129] Du Toit M.H., Avdeenkov A.V., Bessarabov D.; Reviewing H2 Combustion: A Case Study for Non-Fuel-Cell Power Systems and Safety in Passive Autocatalytic Recombiners, Energy Fuels 2018, 32, 6401−6422
[130] Du Toit M.H., Avdeenkov A.V., Bessarabov D.; Reviewing H2 Combustion: A Case Study for Non-Fuel-Cell Power Systems and Safety in Passive Autocatalytic Recombiners, Energy Fuels 2018, 32, 6401−6422

These systems inject the fuel straight into the flame zone where, with appropriate atomization and rapid mixing low NOx emissions can be achieved. This is due to the increased fuel jet momentum and greater mixing resulting from the additional fuel injection ports per air jet. The reduction in NOx emissions is also assisted by the resulting decrease in residence time due to the requirement for a shorter combustion zone. But this results in a larger pressure drop over the combustor.

Catalytic Combustion

Due to the use of catalysts, Catalytic combustion can handle air and fuel mixtures outside of the normal flammability limits to promote combustion at lower temperatures, hence reducing NOx formation.

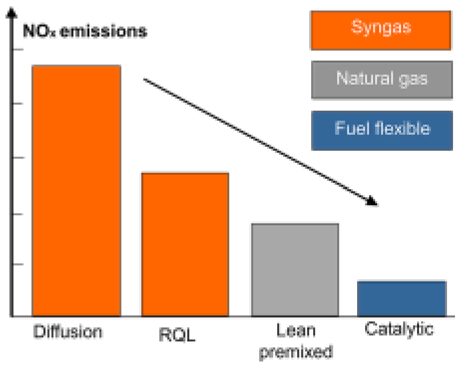

Figure 22 NOx emissions for different combustor technologies[131]

However, it suffers from issues with heat transfer, catalyst activity, durability and cost due to the use of high temperature materials and advanced cooling.

In systems where the turbine inlet temperature is lower than the catalyst temperature limit, the system would include a pre-mixer section where the fuel and air is pre-mixed before it reaches the catalytic reactor. Sometimes a pre-burner is added to keep the catalyst active during low-emission mode. As system efficiency depends on turbine inlet temperatures, low temperatures are not ideal.

In cases where the flame temperature is high, the system consists of two stages. An example of this is the rich-catalytic lean-burn combustion (RCL) system. This was developed for natural gas but has also been successfully tested on syngas and H_2 fuels (see Table 28). It operates at a rich equivalence ratio over the catalyst and then becomes lean downstream due to the air being split into two parts. One part is mixed with the incoming fuel (forming the rich mixture), and the rest is used to cool the reverse of the catalyst, maintaining catalyst activity. Flashback and autoignition are removed as issues and the combustor operates in a stable manner, with low NOx emissions, over different firing conditions.

Altered Oxygen Concentration Combustion

The use of oxidants other than air

– Oxy-fuel: Oxygen is separated from air and then diluted with recycled exhaust gas. The oxidant then comprises a high concentration of O_2 (no N_2), CO_2 and H_2O. The final exhaust gases will be a CO_2−H_2O gas mixture that can be sequestrated more easily. In oxy-fuel, the N_2 in air is basically replaced with CO_2 and the O_2 fraction is increased. CO_2 is heavier than N_2 gas, and replacing N_2 for CO_2 will lead to an increase in the oxidant density, and will in turn change the pressure drop and flame shape. The presence of CO_2 in oxy-fuel increases the heat capacity, which lowers the flame temperature and reduces the flame speed. The increased concentration of CO_2 also reduces the laminar burning velocity and the overall combustion process is inhibited. These disadvantageous properties of CO_2 can be used to reduce chemical reaction rates and therefore reduce the risk for flashback, especially in cases where flashback risk is high, such as in pre-mixed combustion or H_2 fuel combustion. NOx formation is not an issue here because only small amounts of N_2 are available in the combustor

[131] Du Toit M.H., Avdeenkov A.V., Bessarabov D.; Reviewing H2 Combustion: A Case Study for Non-Fuel-Cell Power Systems and Safety in Passive Autocatalytic Recombiners, Energy Fuels 2018, 32, 6401−6422

- Vitiated Air: the O_2 fraction is reduced to levels below that found in normal air (~21 vol%) by diluting air with large amounts of recycled flue gas. This recirculation back to the flame front results in reducing the O_2 content and heating the reactants to above the autoignition temperature. The two processes are:
  - Flameless Oxidation (FLOX) where recirculated inert flue gases significantly dilute the incoming air and fuel delaying the flame reactions and causing combustion to occur over a larger volume. The recirculation of the flue gases reduces the local O_2 concentration, lowering the adiabatic flame temperature and producing homogeneous temperatures with lower temperatures peaks. Thermal NO formation and NOx emissions are reduced as a result. This process results in an invisible flame due to the heavy dilution of the reaction zone. FLOX adopts a specific burner design which uses high momentum jets from orifices distributed around a circle discharging into the combustor. These jets create a recirculation zone, which causes a high level of mixing between hot burnt gases and reactants. Flashback risk is reduced due to the absence of low velocity regions. Additional advantages of this technique are the reduced noise levels and better fuel flexibility.
  - Colourless Distributed Combustion (CDC): Air is pre-heated to elevated temperatures using hot exhaust gases. This enables the peak temperature in the flame region to be reduced and, through an improved thermal field through the combustor, reduces the NOx emissions.

3.7.2.4 Gas turbines summary

The hydrogen conversion plans across the gas turbine sector seem to be converging into two overall themes:

- Turbines using the various dry types of low NOx combustion (such as DLN, or ULN) tend towards development of new technological solutions to support ultimate decarbonisation targets with low NOx. Therefore, it is prudent to assume these cases may require SCR as a back-up, (and/or diluents), because SCR is a well-understood and robust method for secondary NOx abatement. Alternatively, some de-rating may be deployed, however, loss of export capacity would clearly present a significant loss of revenue to the generator.
- Turbines using wet methods (generally smaller, aeroderivative or industrial units) seem to have more flexibility for high hydrogen rates and more options for achieving NOx targets such as increasing water injection rates.

Table 31 presents a summary of current blend limits and future aspirational targets from the major gas turbine OEMs. This summary presents general trends rather than a comprehensive overview of every model and combination of technologies.

Table 31. Gas Turbine OEM hydrogen summary of roadmaps, hydrogen blend levels in vol% and equivalent decarbonisation% (in parentheses)

	Ansaldo	Siemens	MHPS	GE	KHI	Aurelia
Current H_2 blend limits wet/other methods, vol% (decarb%)	25% (10%)	Up to 100%	Up to 100%	20-35% (9%-15%)	30% (12%)	N/A
Current H_2 limits dry methods, vol% (decarb%)	70% (42%)	30% (12%)	30% (12%)	50% (25%)	30% (12%)	30% (12%)
2030 goal for 100% hydrogen?	Yes	Yes	Yes	Yes	Yes	Yes
Advance goals for high-hydrogen or full conversion prior to 2030, where published	40% by 2023 (18%)		2025 test		Diffusion 100% mid-2020s	Mid-2020s
NO_X targets at 100% hydrogen	BREF	BREF	BREF	BREF	BREF	BREF

3.7.3 Boilers

This will have been captured within the recent BEIS consultation on "Enabling or requiring hydrogen-ready industrial boiler equipment" which ran until 14 March 2022[132]. However, the following provides an initial insight until the results of the consultation are made available.

3.7.3.1 Operating Plants

A 1MW industrial boiler has been fired with hydrogen as part of the HyNet Industrial Fuel Switching programme in Manchester[133], this is in addition to the 5MW UT-L series boiler being provided at the plant Wunsiedel Energy Park, Germany[134].

3.7.3.2 OEM Current Capability

Boiler manufacturers see the use of hydrogen as a future fuel although they are promoting their technology as hydrogen ready (see Figure 23 which illustrates Bosch's range of boilers that are "H_2 Ready" [note that the blend of hydrogen has not been stated][135]), but as stated within the BEIS Call for Evidence[136] there is no standardised definition. The use of hydrogen in boiler systems, and the corresponding technology, is commonplace in sectors where hydrogen is created as a waste product such as refineries and chemical processes.

[132] BEIS, December 2021, Enabling or requiring hydrogen-ready industrial boiler equipment, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1042303/hydrogen-ready-industrial-boiler-equipment-call-for-evidence.pdf
[133] D. Mavrokefalidis, 22 January 2021, Could the 'first' hydrogen firing of industrial boiler in Manchester hold the key to UK's decarbonisation?, https://www.energylivenews.com/2021/01/22/could-the-first-hydrogen-firing-of-industrial-boiler-in-manchester-hold-the-key-to-uks-decarbonisation/ accessed 15 March 2022
[134] D. Gosse, Heating energy and process heat using climate-neutral hydrogen, www.bosch-industrial.com, 05/2021
[135] F. Guerrero, D. Gosse, M. Raisach, April 2020, INDUSTRIAL BOILERS – HYDROGEN Steam · Heat · Power, Bosch
[136] BEIS, December 2021, Enabling or requiring hydrogen-ready industrial boiler equipment, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1042303/hydrogen-ready-industrial-boiler-equipment-call-for-evidence.pdf

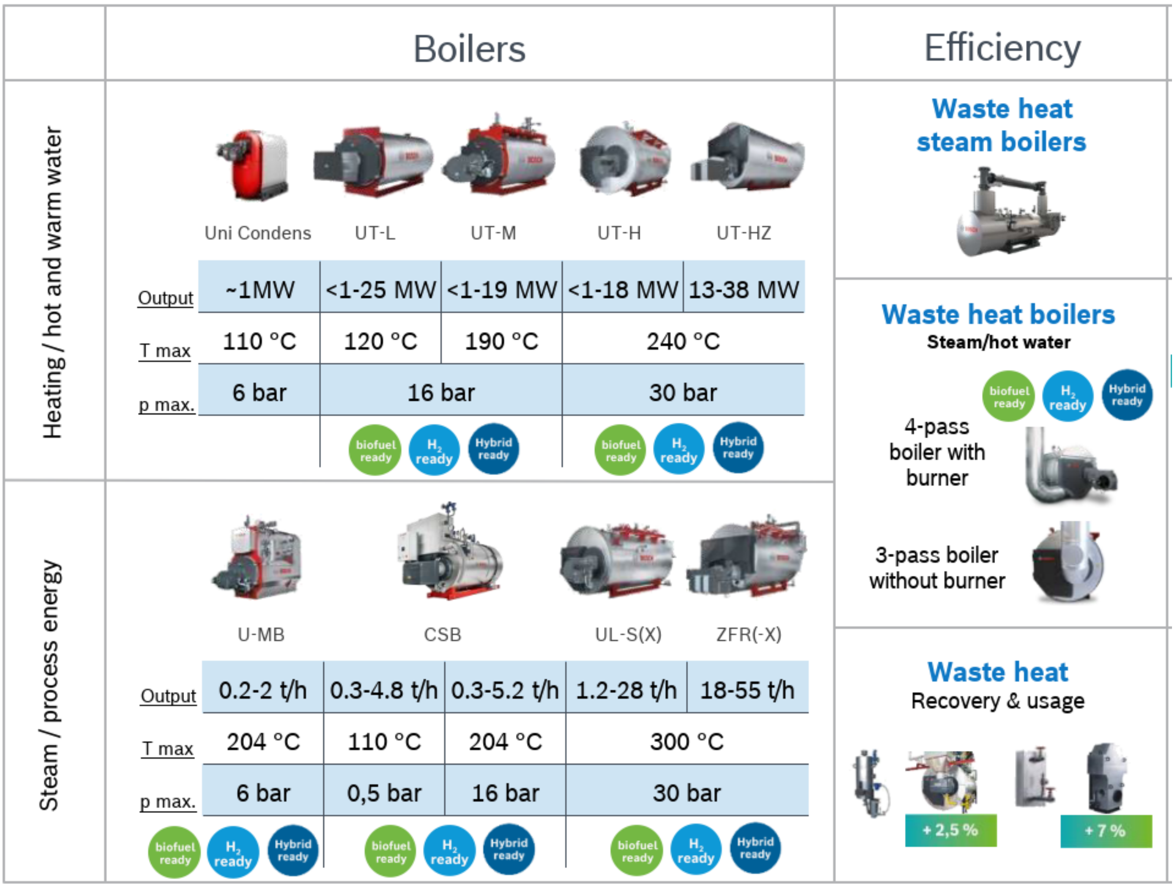

Figure 23 Bosch Boiler Technology

Bosch claim to have implemented a number of boiler systems that are operated on pure hydrogen[137] and are supplying a 5 MW UT-L series boiler to the Wunsiedel Energy Park, Germany for use with a 100 vol% hydrogen fuel. It is being developed to initially operate on natural gas and allow flexible operation with hydrogen[138]. This plant was expected to be operational at the end of 2021.

Bosch identify that for their Marathon® gas/ dual fuel burners they are restricted to a fluctuation in the Wobbe number of ±2%. However, Bosch consider that a fuel supply of <5 vol% hydrogen (1.7% decarbonisation) can be accommodated provided the range of the Wobbe number is maintained. This can be achieved through oxygen control. For fuel blends of <10 vol % hydrogen (<3.4% decarbonisation) operation could be achieved without changing the mixing device but would require burner readjustment. Fuel blends >10 vol% hydrogen (>3.4% decarbonisation) would require technical adjustments and approvals from CE monitoring bodies[139].

As of 2020 Cochran were claiming that they would be capable of supplying "H2 Ready" boilers where there was an expectation for up to 20 vol % hydrogen[140] (7.4% decarbonisation).

3.7.3.3 Technical Development Barriers

These are similar to the issues facing gas turbines, as measures will be required to address the increase in fuel volume, control the higher combustion temperatures (and resultant NOx emissions), faster combustion behaviour, materials of construction and "soft ignition" measures[141]. This will have a particular influence on fuel lines, nozzles, high-temperature-resistant components that come into contact with flames, burner fans and the combustion chamber.

[137] D. Gosse, Process heat supply in the context of decarbonisation – how will the industrial boilers of the future look?, www.bosch-industrial.com 09/2019
[138] Bosch, Press Release, November 2020, Bosch is supplying hydrogen boiler, https://www.bosch-presse.de/pressportal/de/en/bosch-is-supplying-hydrogen-boiler-221184.html accessed 15 March 2022
[139] F. Guerrero, D. Gosse, M. Raisach, April 2020, INDUSTRIAL BOILERS – HYDROGEN Steam · Heat · Power, Bosch
[140] https://www.cochran.co.uk/news/general/cochran-hydrogen-ready
[141] F. Guerrero, D. Gosse, M. Raisach, April 2020, INDUSTRIAL BOILERS – HYDROGEN Steam · Heat · Power, Bosch

It is noted that a 100 vol% hydrogen fired boiler can be up to 10 % larger than a natural gas boiler to produce the same output[142].

Achieving the regulatory required NOx limits is usually achieved through reduction in flame temperature by the use of flue gas recirculation[143].

For the prevention of back firing, flame arrestors are incorporated into the combustion system upstream of the hydrogen burners. These can be either static or dynamic arrestors. Bosch identify that regulations for hydrogen burners in industrial boiler plant are not currently available. This requires that each unit needs to be assessed on a case-by-case basis taking into account issues such as explosion protection, materials selection, suitability of equipment and operational aspects[144].

Existing flue gas technology can be adopted. The use of condensing heat exchangers allow waste heat to be recovered and can result in fuel savings of up to 7%, although this requires connection to a suitable heat sink. When using condensing technology with hydrogen combustion and flue gas recirculation consideration needs to be given to aspects such as low return flow temperatures in warm/hot water boilers[145].

It is stated that for industrial process heating systems the acquisition costs accounts for ~2% of the total operating costs over a 15-year operational period[146].

3.7.4 Reciprocating Engines

3.7.4.1 Operating Plant

HyChico have operated a hydrogen plant in Chubut Province, Argentina since December 2008. The plant uses two electrolysers to produce 120 Nm^3/h of hydrogen (purity 99.998%) which is blended (at up to 42 vol% hydrogen (17.6% decarbonisation)) with natural gas to feed a 1.4MW genset. The genset uses a Jenbacher J420 gas engine which has delivered 70,000 hours of operation.

3.7.4.2 OEM Current Capability

In 2020[147] INNIO Jenbacher successfully demonstrated operation of a prototype engine on 100 vol% hydrogen in Hamburg, Germany, this has now progressed to the position where all Jenbacher Type 4 gas engines (output of approximately 500 – 900 kW) are available as “Ready for H2” and able to operate on up to 100 vol% hydrogen[148] (details of these engines at 100% hydrogen are illustrated in Table 32[149]). From 2022 all Jenbacher engine types are being offered as “Ready for H2” with the option of being able to be fuelled by pipeline gas at <25 vol% hydrogen (<9.7% decarbonisation).

Table 32 Technical Details for Jenbacher Type 4 Gas Engines for 100% Hydrogen

Fuel	Engine Types	Electrical Output		Thermal Output	
		50 Hz (kWe)	60 Hz (kWe)	50 Hz (kW_{th})	60 Hz (kW_{th})
Hydrogen	J412	531	528	630	674
NOx <100 mg/Nm^3 @ 5% O_2	J416	710	707	838	899
	J420	889	890	1,049	1,124

Jenbacher claim that their “Ready for H2” and most of their currently installed natural gas units can be converted to operate on 100 vol% hydrogen[150]. INNIO Jenbacher’s ‘Ready for Hydrogen’ engine

[142] D. Gosse, Heating energy and process heat using climate neutral hydrogen, www.bosch-industrial.com. 05/2021
[143] D. Gosse, Heating energy and process heat using climate neutral hydrogen, www.bosch-industrial.com. 05/2021
[144] D. Gosse, Heating energy and process heat using climate neutral hydrogen, www.bosch-industrial.com. 05/2021
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[146] D. Gosse, Process heat supply in the context of decarbonisation – how will the industrial boilers of the future look?, www.bosch-industrial.com 09/2019
[147] Press Release, 16 September 2020, New hydrogen engine from INNIO ready for operation after passing all tests,
[148] Press Release, 21 July 2021, INNIO Jenbacher Gas Engines Ready for Hydrogen, https://www.innio.com/en/news-media/press-releases/innio-jenbacher-gas-engines-ready-for-hydrogen, Accessed 10 March 2022
[149] https://www.innio.com/en/solutions/power-generation/hydrogen-fired-power-generation Accessed 11 March 2022
[150] Press Release, 21 July 2021, INNIO Jenbacher Gas Engines Ready for Hydrogen, https://www.innio.com/en/news-media/press-releases/innio-jenbacher-gas-engines-ready-for-hydrogen, Accessed 10 March 2022

technology has been selected by Hyosung Heavy Industries (Hyosung) which will be the second plant in their 1 MW range to be fuelled on 100% hydrogen. This is expected to achieve commercial operation in the third quarter of 2022[151]. In addition to these 100% hydrogen projects, INNIO has experience across their portfolio of operating around 90 hydrogen-rich fuel projects, on up to 70% volume of hydrogen in the fuel, yielding more than 250 MW[152].

Whilst these are the first units in the <10MW generating sector, other suppliers are pursuing a 100% hydrogen fuelled capability. For example, Rolls Royce's MTU Series 500 and Series 4000 can operate at 10 vol% hydrogen (3.4% decarbonisation) currently, with operation at 25 vol% (9.7% decarbonisation) expected in 2022 and 100 vol% hydrogen in 2023, they are also expecting to make conversion kits available to allow currently installed engines to be converted to 100% hydrogen[153]. This is a similar situation with other reciprocating engine manufacturers such as Wärtsilä[154] and MAN Energy Solutions[155] both claiming their engines are capable of operating on <25 vol% hydrogen (<9.7% decarbonisation) currently and that they are also pursuing 100% hydrogen fuelled engines (Wärtsilä having tested with 60 vol% hydrogen (32.5% decarbonisation) blends[156]).

3.7.4.3 Technical Development Barriers

Evidence from the HyChico project[157] demonstrates the de-rating of the gas engine performance with increasing concentrations of hydrogen within the fuel blend. This is illustrated in Figure 24

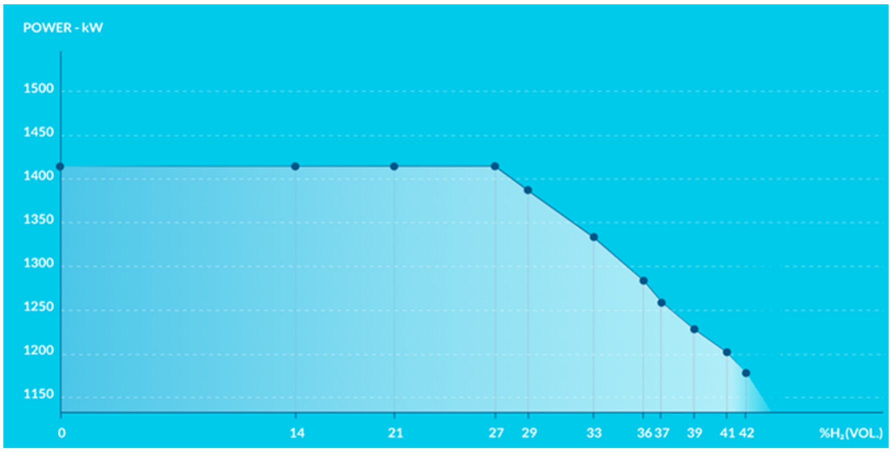

Figure 24 Power Variation as a Function of Hydrogen Content

Figure 24 shows that with hydrogen blends <27 vol% hydrogen (11% decarbonisation), full power can be achieved (1,415kW) but as the hydrogen blend increases (from 28 vol% to 42 vol% hydrogen (11%-18% decarbonisation, respectively)) the power is gradually decreased to 1,180kW (a 16.6% drop) to prevent engine knocking. Table 33 illustrates the effects of de-rating in the Pilot Project[158].

[151] Press Release, 19 November 2021, INNIO Technology Selected for First 100% Hydrogen Engine Power Plant in Asia Pacific, https://www.innio.com/en/news-media/press-releases/innio-technology-selected-for-first-100-hydrogen-engine-power-plant-in-asia-pacific, Accessed 10 March 2022
[152] Press Release, 21 July 2021, INNIO Jenbacher Gas Engines Ready for Hydrogen, https://www.innio.com/en/news-media/press-releases/innio-jenbacher-gas-engines-ready-for-hydrogen, Accessed 10 March 2022
[153] Press Release, 15 October 2021, ROLLS-ROYCE LAUNCHES mtu HYDROGEN SOLUTIONS FOR POWER GENERATION, https://www.mtu-solutions.com/eu/en/pressreleases/2021/rolls-royce-launches-mtu-hydrogen-solutions-for-power-generation.html, Accessed 10 March 2022
[154] Press release, 5 May 2020, Wärtsilä gas engines to burn 100% hydrogen, https://www.wartsila.com/media/news/05-05-2020-wartsila-gas-engines-to-burn-100-hydrogen-2700995, Accessed 11 March 2022
[155] Press Release, 4 November 2021, H2-ready: MAN Gas Engines Enable Hydrogen Use in Power Plants, https://www.man-es.com/company/press-releases/press-details/2021/11/04/h2-ready-man-gas-engines-enable-hydrogen-use-in-power-plants; Accessed 11 March 2022
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[157] HyChico, http://www.hychico.com.ar/eng/hydrogen-plant.html, Accessed 11 March 2022
[158] https://www.innio.com/en/solutions/power-generation/hydrogen-fired-power-generation Accessed 11 March 2022

Table 33 INNIO Jenbacher Field Conversion from Natural Gas to Hydrogen Operation Pilot Project Data

	Natural Gas Operation (main operation mode)	H_2 Operation (optional)
Electrical Output	999 kW	>600 kW
Electrical Efficiency	~42%	~40%
Total CHP Efficiency	~93.5%	~93%

The plant also demonstrated that by reducing the exhaust gas temperature (by increasing the lambda coefficient[159]) the NOx concentration reduced by 58% and CO concentration by 48% in the exhaust (see Figure 25 and Figure 26 respectively)[160].

Figure 25 NOx Emission Reduction as a Function of Lambda

[159] Lambda (λ) is the Air-fuel equivalence ratio which is the ratio of actual Air-Fuel Ratio to stoichiometry Air-Fuel Ratio (λ = 1 is at stoichiometry, rich mixtures λ < 1, and lean mixtures λ > 1)

[160] HyChico, http://www.hychico.com.ar/eng/hydrogen-plant.html, Accessed 11 March 2022

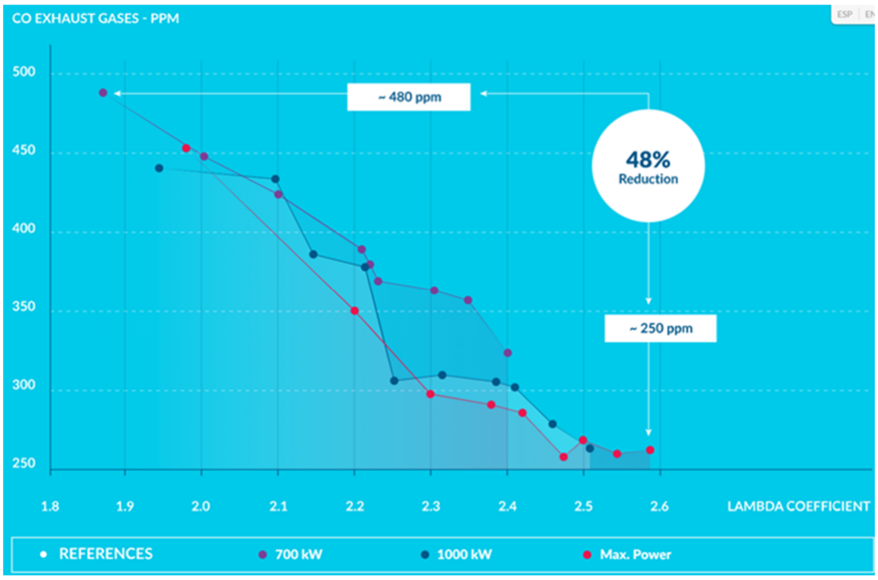

Figure 26 CO Emission Reduction as a Function of Lambda

3.7.4.4 Reciprocating engines summary

Table 34 below shows a summary of the current level of blending tested on commercial reciprocating engines, with future targets.

Table 34. Reciprocating engine OEM hydrogen summary, hydrogen blend levels in vol% (and equivalent decarbonisation% in parentheses)

Company	Current status	Target
Caterpillar	• None commercially operating with high hydrogen concentration • Existing units capable of handling ~10vol% H_2	• Targeting release of 1.2MW engine that is 100% H_2 in 2022 (Model C3516H) • Targeting 25% hydrogen retrofit capability on all generators by Q4 2022
Jenbacher / Waukesha	• One 600kW 100% H_2 demonstration unit operational • One 1.4MW 100% H_2 unit in development	• Plan to release full range of 100% H2 ready engines in 2022 (unclear if dual fuel)
Man	• Most units capable of firing 10% (3%) H_2 already • Three models capable of firing 25% (10%) H_2	• Working on higher concentration units
Siemens	• Further work to understand capability, S class machine has some high H_2 capability	
Wartsila	• Have successfully tested up to 60% (32%) H_2 with 40 vol% CH_4	• Working on higher concentration units
Bergen	• Up to 10% (3%) H_2 for MN 80 upwards with minimal changes • Possibility to increase to up to 60 (32%) H_2 through de-rating with potential for some minor modifications	• Beyond 60 vol% H_2 (32%), modification to engine and fuel supply systems will be required • Currently undertaking tests on B35:40 natural gas engine in lab, with scope to launch pilot project in 2022.

4. Conclusions & Recommendations

4.1 Conclusions

The evidence base for demonstrating hydrogen readiness has been developed in this review, according to the five assessments required by BEIS, summarised below.

4.1.1 Key Differences Between Hydrogen and Methane

Table 35. Summary of main differences between hydrogen and natural gas

Characteristic	Commentary
Heat of Combustion	• Less than a 1/3 of methane • Volumetric flow > 3 times methane resulting in constraints in fuel distribution systems
Wobbe Index	• Measure of fuel interoperability - similar to methane • Blends with Wobbe values 30 – 50 MJ/m^3 can be used in combustion systems without large scale modifications
Flame stability	• Lewis Number less than half the value of methane leading to a more unstable flame
Adiabatic Flame Temperature	• Higher than methane • Results in 3 times the thermal NOx production (local at flame)
O_2 Demand	• Lower than methane
Burning velocity	• Greater than methane (max. is approx. 7 times) - affects burning rate • Position of flame front, flashback risk & flame stabilisation. Potential for increased risk of damage
Emissivity	• Lower than methane • Resulting in flames with lower luminosity requiring ultraviolet rather than infrared flame detection instrumentation
Flammability	• Lower flammability limit and wider flammability range than methane; requiring different procedures and expanding safety zones
Leak Potential	• Smaller molecule than methane, readily diffuses through common materials • Alternative sealing systems e.g. welded connections may be required

4.1.2 Objective 1 – Footprint

Table 36. Summary of main footprint requirements for Hydrogen Readiness

Characteristic	Commentary
Supply infrastructure	• New build receiving infrastructure will be comparable to NG equivalent • Difference in pipe diameter will have minimal impact • Sites with both H2 and NG will need additional space of 20 – 50m^2 (low pressure systems) to 900m^2 (high pressure systems)
Hydrogen storage	• Dependent on inventory required • Economic case of full supply chain needs to be considered • Carbon footprint of full supply chain needs to be considered
Hydrogen blending	• Equipment (valves/ metering etc) typically available as skid mounted or ISO Containers requiring footprint of 10ft - 40ft ISO Container (7m^2 - 30m^2)
Combustor/burner modifications	• Replacement of Dry Low NOx type is negligible (preferred type on new build & retrofits); Wet Low NOx type will require a water injection package of <4m^2 footprint
Flue gas recirculation	• Equipment specific and cannot be generically assessed
Emissions abatement	• Consideration of additional equipment required including: – Ammonia/urea storage

Characteristic	Commentary
	– Reactant pumps and control skid – Catalytic grid and housing • SCR has been included as an optional item with footprint broken out from overall estimate

4.1.2.1 On-site storage

Approximate equipment footprint requirements have been estimated for five different options, from 750m^2 for mobile tube trailer options to 2250m^2 for large cryogenic liquid hydrogen spheres. However, the selection of on-site storage quantity and technology will be the output from the estimated hydrogen consumption rate which is itself driven by a site-specific load profile. Therefore, the case studies examined within this review have all been based on reliable supply of hydrogen to site by pipeline to enable consistent comparison.

4.1.3 Objective 2 – Checklists

The final checklists have been issued to BEIS for review, refer to Appendix C. These represent a new hydrogen-specific checklist (as well as a consolidated carbon capture checklist specific to power generators seeking to use carbon capture on site). The hydrogen checklist has been developed to meet the needs of power generators sourcing hydrogen from an external hydrogen hub or through on-site production and/or buffer storage.

Full hydrogen firing is not yet proven for the majority of power generation equipment. Therefore, the viability of future conversion to full hydrogen firing will be challenging to assess with a limited number of reference cases at time of writing. It may be necessary to consider techniques such as partial blending, though this would also require understanding of the full composition of the fuel as this will have an impact on its performance, carbon intensity, and therefore relevance to predicting the feasibility of future conversion to full hydrogen.

4.1.4 Objective 3 – Hydrogen Supply Chain

This review has examined the hydrogen supply chain in relation to supply of hydrogen to sites that may not have reliable pipeline supply and therefore wish to deploy on-site storage with either batch delivery of hydrogen to site or on-site production. The gas consumption rate for various typical gas turbine examples has been calculated, shown in Table 37 at 100% load.

Table 37 Electrolysis Requirement Supporting 100% Hydrogen Operation

Gas Turbine	Output† MW	Heat Input† GJ/h	100% H_2 Flow Rate m^3/h	t/h	Water Required to Generate H_2 m^3/h	Electrolysis Power Required†† GWh
GE-10	11.2	129	~11,700	~1	~10	~500
6B.03	44	473	~43,000	~4	~37	~2,000
6F.03	87	857	~78,000	~7	~68	~3,600
9F.04	288	2,677	~243,500	~23	~212	~11,400
9HA.02	557	4,560	~415,000	~38	~361	~19,500

† ISO conditions operating on natural gas and simple cycle operation. Heat input is High Heating Value.

†† Power required for electrolysis to supply H_2 flow for gas turbine to operate on 100% H_2 for 8,000 hours

At the CHP scale, a typical 11MW gas turbine would be expected to consume on the order of 1t/hr at 100% load with 100% hydrogen fired operation. The consumption rate of hydrogen in utility-scale power generation such as H-Class is expected to be on the order of 38t/hr at 100% load with 100% hydrogen fired operation. The water consumption to produce such hydrogen by electrolysis would be 10m³/hr to

361m³/hr, respectively. Research is underway to improve energy, cost and water efficiencies of producing hydrogen by a variety of means to bring the methods closer to the thermodynamic limits associated with splitting water molecules or make better use of the oxygen co-product elsewhere. The potential role for on-site manufacture of hydrogen for power generation seems more applicable to small-scale peaking plant where a lower capacity factor can be used to offset periods of consumption with relatively steady periods of hydrogen generation, fed by low-carbon energy sources as defined by the Low Carbon Hydrogen Standard. Satisfying the needs of hydrogen production for large plant that may be required to run for extended periods of time seems more suited to offsite centralised means for production and storage such as seasonal underground caverns.

This review has also considered the role for on-site storage, either for on-site produced hydrogen, or delivery from offsite production sources. On-site storage has been explored in the context of providing hours of firing 100% hydrogen at 100% load for each case study, which have been calculated for five different storage sizes to represent the full range of industrially-deployed hydrogen storage tank sizes:

1. 2 x 228 barg mobile tube trailers (1.2 tonnes of gaseous hydrogen)
2. 2 x 300 barg mobile tube trailers (1.8 tonnes of gaseous hydrogen)
3. 4 x 350 barg horizontal stationary bullets (4.85 tonnes of gaseous hydrogen, selected to reasonably represent maximum allowable storage without incurring Lower Tier COMAH threshold)
4. Small stationary cryogenic liquid hydrogen sphere (38 tonnes of hydrogen, exceeds Lower Tier COMAH)
5. Large stationary cryogenic liquid hydrogen sphere (270 tonnes of hydrogen, exceeds Upper Tier COMAH)

The review has found on-site hydrogen storage for power generation to be challenging if the storage is to be used for long periods of generation at full load. For example, none of the studied gaseous hydrogen storage configurations would support an extended outage such as 5 days at 100% load for any of the case studies. 5 days represents a reasonable industry benchmark for buffer storage of production-critical utilities, therefore, the gaseous storage options seem more suited to buffering short durations of intermittent operation.

For liquid hydrogen storage, the small cryogenic sphere was found to meet the 5-day hold-up test for plant up to approximately 2MW (136 hours for 2MW OCGT). For the large sphere, the threshold for 5 days buffer storage appeared to be approximately 20MW (between the 14MW and 35MW CHP-scale CCGT case studies at 196 and 96 hours, respectively). However, the cryogenic sphere storage volumes would incur COMAH thresholds. In addition, supply of liquid-phase hydrogen as opposed to gaseous raises additional efficiency penalties through liquefaction, transport, boil-off, vapourisation and recompression prior to use; the impact of which should be considered on the performance of the power generator at point-of-use. Further, the quantity of hydrogen that can be supplied to site from a remote facility will be limited by the carrying capacity of the vessel or trailer. Design of hydrogen transportation equipment is an active area of research, however, it is expected that there will remain significant logistical challenges for moving large quantities of hydrogen to sites without reliable pipeline supply such as provision of the unloading facilities at the consumer site.

4.1.5 Objective 4 – Economics

4.1.5.1 Capital Cost

The capital costs per MW thermal input for each case study show significant variation across the case studies (from £M 0.02/MWth to £M 1.17/MWth for CS3 and CS13, respectively). The data indicates the greatest cost for the reciprocating engine case studies where the impact of converting an array of small units limits the degree of cost efficiency. The estimated capital costs have been scaled from AECOM's previous internal project data. The average level of uncertainty associated with the total capital cost estimates in this review is approximately -50%/+60% either side of the central calculated CAPEX value.

The estimated conversion costs in this review have been calculated assuming a conservative 'First-Of-A-Kind' conversion with a commensurate degree of associated project development activities (such as engineering, permitting, as well as potentially some on-site enabling works that might be expected for a typical site). It is expected that as the market matures and standardised solutions become readily available for the key hydrogen-fired power generating equipment, the associated additional costs to deliver fuel switching would reduce. An overall CAPEX reduction of up to 50% may be achievable for ‘Nth-Of-A-Kind’ plant once key equipment by streamlining the cost of key equipment optimising the Given the factored methods for calculating cost estimates in this review, it seems plausible that an overall CAPEX reduction of up to 50% may be achievable for ‘Nth-Of-A-Kind’ plant.

4.1.5.2 Operating Cost

For all the case studies, the additional operating cost estimate was calculated as approximately £91--92 per MWth of input. This estimate comprises the variable fuel and SCR reagent costs. It has been assumed within this review that the difference to fixed costs such as maintenance and operations would be negligible following conversion to hydrogen.

The operating cost value calculated within this review is particularly sensitive to the cost of the input fuel which comprises approximately 90-95% of the calculated OPEX figure. Therefore, projects exposed to future wholesale hydrogen pricing (such as those seeking to utilise blue hydrogen from a centralised supply network) will be particularly vulnerable to price fluctuations and will likely seek to purchase their fuel during periods of relatively low cost wherever possible.

4.1.6 Objective 5 – Development of Hydrogen Readiness

The major manufacturers of power generation have all announced development programmes to enable conversion of their fleets to enable hydrogen firing. A range of techniques is being investigated, with a summary of the roadmaps put forward by each sector shown in Table 38.

Table 38. Roadmap for readiness of firing of varying levels of hydrogen in methane for the different combustion technologies

Hydrogen blend, Vol%	decarb.%	Gas turbines	Boilers	Reciprocating engines
10%	3%	Widely achieved across many models with changes achievable through readily available means	Testing of first 100%-hydrogen prototype units at 1MW+ scale is underway, with active development programmes from OEMs. Wider deployment expected with techniques such as fuel staging and exhaust recirculation expected to provide BREF-compliant performance. Industry-standard definition of “Hydrogen-Ready” would allow detailed comparison.	Widely achieved across many models with changes achievable through readily available means
20%	7%			Potentially achievable with current technology with additional changes such as some de-rating to prevent knocking.
30%	12%			Barriers to overcome include requirement to further de-rate the equipment above as well as dilute the combustion mix with air to reduce NO_X.
50%	24%	Generally restricted today to models with staged burners or diffusion burners. Development underway to achieve this level with Dry Low NOx type combustors, with first tests between 2022-2025, and supply of first commercial models planned before 2030. Exceptions are: GE’s DLN 2.6e-equipped units (50vol%) and Ansaldo GT36 (70vol%).		
70%	43%			
100%	100%	Generally restricted to equipment with diffusion-type burners. Development underway to develop Dry Low NO_X combustion techniques for 100% hydrogen, with performance targets extrapolated from current BREF guidance.		Testing of first 100%-hydrogen prototype units is underway, with active development programmes from OEMs. Development targeted at minimising impacts on performance and NOx.

Source: <Source>

The overall timeline for achieving increasing fractions of hydrogen blending – especially in the context of achieving system-scale decarbonisation – seems to be to consistent across the industry to deliver the first commercial units prior to 2030, however, evidence is not available for drawing conclusions in relation to the expected date of first supply of 100% hydrogen equipment. The main development pathways seem to be consistent with two overall themes:

- Those seeking to deploy Dry Low NO_x type technologies (such as staged combustion or cluster combustion) which, once ready, is expected to provide up to 100% hydrogen performance with BREF-compliant performance. This requires ongoing development and testing of the respective Dry Low NO_X technology and may depend on securing investment. If deployed at scale, this method may allow operation on full hydrogen without performance penalty or additional secondary treatment.
- Those seeking to utilise existing readily-available combustion technologies, tending towards use of NOx control techniques such as steam, water and/or nitrogen injection for NOX control. Development is aimed at minimising the negative impacts of switching to hydrogen which, to an extent, are expected to remain necessary part of fuel switching with current technologies (such as de-rating or use of additional secondary treatment)

4.2 Recommendations

4.2.1 Objective 1

Further work may seek to derive a standard method for mapping the required on-site hydrogen storage quantity, as well as the optimal storage conditions.

4.2.2 Objective 2

Projects that intend to reuse the same fuel gas supply piping between natural gas and hydrogen may wish to design the piping for hydrogen service (with modifications where necessary for safe operation in natural gas service) even if they do not intend to use the hydrogen capability from the outset.

4.2.3 Objective 3

Projects that wish to include non-pipeline supply of hydrogen as part of their applications for Hydrogen Readiness should define their intent for on-site storage and production (if any). The connection between on-site storage inventory, consumption and resupply rates should be understood and demonstrated.

4.2.4 Objective 5

An industry-standard definition of “Hydrogen Readiness” for equipment would assist in comparing the progress of different technology options in terms of increasing levels of hydrogen blends.

Appendix A Literature Review Documents

A.1 Documents Reviewed & Used

The following section lists the documents that have been reviewed in the course of the study. The first set are those that have informed the study and the second set are those that have been reviewed but have not been referenced.

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A.3 Stakeholders Contacted

Table 39. Manufacturers contacted during study

Manufacturer	Product Type	Date of Initial Contact	Response Received
Gas Turbines			
Siemens	2 to 590 MWe	10/03/2022	Yes
MHI	40 to 570 MWe	01/03/2022	Yes
GE	34 to 570 MWe	16/03/2022	Yes
Ansaldo	80 to 540 MWe	10/03/2022	No
Baker Hughes	5 to 170 Mwe	16/03/2022	Yes
Centrax	3 to 15 Mwe	10/03/2022	No
MAN	6 to 12 Mwe	16/03/2022	Yes
Kawasaki	< 3 MWe	15/03/2022	Yes
OPRA	< 3 MWe	10/03/2022	No
Aurelia	< 1 MWe	15/03/2022	Yes
Capstone	< 1 MWe	10/03/2022	No
Turbotec	< 1 MWe	10/03/2022	No
Reciprocating Engines			
Hyundai Heavy Industry	1 to 26 MWe	14/03/2022	No
MAN	7 to 20 MWe	16/03/2022	Yes
Jenbacher	0.2 to 10 MWe	17/03/2022	No
Wartsila	1 to 9 MWe	17/03/2022	No
Caterpillar	0.1 to 5 MWe	18/03/2022	No
MTU	0.2 to 3 MWe	14/03/2022	No
Rolls Royce Bergen	1-10 Mwe	17/03/2022	Yes
Siemens	0.1 to 2 MWe	16/03/2022	Yes
Industrial Boilers			
Macchi	Field erected, prefabricated	16/03/2022	No
MHPS	Field erected, prefabricated	01/03/2022	Yes
Babcock Wanson	Prefabricated, package	16/03/2022	No
HKB	Prefabricated, package	16/03/2022	No
Cochran	Package	16/03/2022	No
Bosch	Package	16/03/2022	No
ICI Caldaie	Package	16/03/2022	No
Byworth	Package	16/03/2022	No
Electrolysers			
Cummins	Alkaline, PEM	10/03/2022	Yes
Nel.	Alkaline, PEM	15/03/2022	No
ITM Power	PEM	10/03/2022	Yes
Siemens Silyzer	PEM	16/03/2022	Yes
Sunpower	Alkaline, SOEC	18/03/2022	No
CPH2	Membrane free	18/03/2022	No
McPhy	Alkaline	10/03/2022	No
SMR Manufacturers			
Air Products	PRISM	17/03/2022	No
Linde	HYDROPRIME	17/03/2022	No

Appendix B DCR Checklist Recommendations

Table 40. Recommendations for H_2 DCR checklist, red text indicates updates from 2009 CCR Guidance text

ID	Title	Description	Category	Comments
B1	Design, Planning Permissions and Approvals	Note B1: A pre-feasibility-level conceptual hydrogen conversion study should be supplied for assessment, showing how the proposed Hydrogen Readiness (HR) features would make conversion to hydrogen firing technically feasible, together with an outline level plot plan for the plant retrofitted with the hydrogen conversion. If the plant is not also going to be hydrogen-ready at the outset, then the justification for this should be provided.	Not Valid - Amend	Rephrased
B2	Power Plant Location	Note B2a: The work undertaken on hydrogen transport and any storage for the project should be referenced; the entry point of gases to the curtilage of the plant, location of storage (if any) and how this affects the configuration of the power island is the important aspect for the Environment Agency. Note B2b: Health and Safety items in this section are outside the Environment Agency remit.	Not Valid - Amend	
B3	Space Requirements	Note B3: It is expected that all of the provisions in a-i will be implemented, including the provision of space and access to carry out the necessary works at the time of retrofitting without excessive interruptions to normal plant operation. A statement is required to define the level of formal project development that has been undertaken in support of the space requirement calculations, with reference to a standard methodology such as FEL stages, or equivalent. Alternatively, reference may be made to the standard examples of plant sizes, if appropriate. Further details are requested in the following sections as appropriate. Space will be required for the following: a) Fuel gas supply comprising hydrogen delivery, as well as any dual fuel provisions, if appropriate; b) Hydrogen fuel gas production facilities, if hydrogen is to be produced on-site, including any pre-treatment, conditioning, cooling and other utilities. c) If oxygen is co-generated on-site for further use, any hold-up storage and oxygen bulk handling requirements are to be identified. d) Space for piping hydrogen-rich fuel gas to the gas turbine, and for gas compression equipment if required. e) Steam turbine island additions and modifications (e.g. space in the steam turbine building for supplying and receiving steam to/from the hydrogen production facilities). f) Extension and addition of emissions control equipment and diluent, if appropriate, such as: SCR reagent, additional catalyst, nitrogen or steam/water injection. g) Additional vehicle movements. h) Space allocation considering storage and handling of hydrogen, oxygen if appropriate and of CO_2. i) If on-site storage is envisaged, then space shall be explicitly allocated for storage and indicated on the layout.	Not Valid - Amend	

B4	Prime mover operation with hydrogen-rich fuel gas	Note B4: A statement is required confirming that it will be possible to modify the prime mover to accommodate firing on hydrogen-rich fuel gas in the future and estimating the future performance. A statement is required to confirm that the conversion of the prime mover will investigate the main relevant matters for fuel switching, such as: materials issues and embrittlement, the impact on NOx generation and IED compliance, leak detection and safeguarding, as well as the difference in combustion properties.The prime mover must be able to be modified to operate with the proposed hydrogen-rich fuel gas (including achieving any likely environmental restrictions on the emissions of NOx, possibly with the addition of selective catalytic reduction equipment - SCR).	Not Valid - Amend
B5	Heat recovery steam generator, HRSG, and plant steam cycle	The heat recovery steam generator must be designed to accommodate the changed flue gas composition and temperatures after hydrogen conversion. The steam cycle as a whole must also be designed to accommodate the needs of the hydrogen production facility (if present on site), both for providing any additional steam supplies to that facility and for the use of any additional steam production in the hydrogen production facility, to allow reasonable thermal integration and hence overall plant efficiency after retrofit. Note B5: A statement is required describing any changes in the requirements for the HRSG and steam cycle after conversion and how they will be modified to accommodate this.	Not Valid - Amend
B7	Cooling Water System	On site generation of hydrogen will impose its own cooling demand. Note B7: A statement is required of estimated cooling requirements (as heat loads, flows and/or temperatures of cooling water) and how these will be met. If independent cooling is to be provided for the hydrogen generation equipment, then the necessary space is to be allocated and a description of the potential cooling options is to be provided. If tie-in to the power island cooling system is to be undertaken, then a statement is required to demonstrate satisfactory operation of the combined facility.	Not Valid - Amend
B8	Compressed Air System	The capture equipment addition will call for additional compressed air (both service air and instrument air) requirements. Note B8: A statement is required if intending to rely on existing facilities for compressed air (instrument and/or plant) that sufficient capacity is expected to be provided. In case new facilities are planned, a statement is required that sufficient space has been allocated for equipment, proportionate to the scale of equipment likely to be installed to service the process.	Not Valid - Amend
B9	Raw Water Pre-treatment Plant	Space shall be considered in the raw water pre-treatment plant area to add additional raw water pre-treatment streams, as required. Note B9: A statement is required of estimated treated raw water requirements together with a description of how these will be accommodated.	Valid - Retain Unamended
B10	Demineralisation / Desalination Plant	Additional supplies of demineralised water are likely to be required after retrofitting e.g. for feedstock in the hydrogen production facility and possibly in the prime mover NOx control system. Estimates of any such water requirements should be made and space allocated for the necessary treatment plant (and an additional water source be identified if necessary). Note B10: A statement is required saying which of the above are needed and in what quantity and also describing how the necessary provisions will be implemented.	Not Valid - Amend

B11	Waste Water Treatment Plant	Water processing for hydrogen production is expected to result in generation of additional waste water effluents. Note B11: A statement is required giving estimated additional waste water treatment needs and describing how the necessary space and any other provisions will be provided to meet expected demands.	Not Valid - Amend
B12	Electrical	The introduction of the hydrogen production facility with pre-combustion capture will lead to a number of additional electrical loads (e.g. pumps, compressors). Note B12: A statement is required listing the estimated additional electrical requirements and describing space allocation in suitable locations for items such as additional flue gas recirculation (if appropriate), switchgear, cabling and transformers.	Not Valid - Amend
B13	Plant Pipe Racks	Installation of additional pipework after retrofit with capture will be required, e.g. for gas and steam transport and additional cooling water piping and possibly other plant modifications. Note B13: It is expected that provision will be made for space for routing new pipework at the appropriate locations. A statement identifying anticipated significant additional pipework and describing space allocations to accommodate these is required.	Valid - Retain Unamended
B15	Plant Infrastructure	Space at appropriate zones to widen roads and add new roads (to handle increased movement of transport vehicles), space to extend office buildings (to accommodate additional plant personnel after hydrogen conversion) and space to extend stores building are foreseeable. Commitment from the project to establish a laydown strategy as part of the wider constructability philosophy will be required. The laydown strategy would consider a range of topics in relation to the hydrogen conversion such as (but not limited to), how, during a retrofit, vehicles or cranes will access the areas where new equipment will need to be erected, and how the project will ensure sufficient area is available for temporary laydown.	Not Valid - Amend

Appendix C Technical Notes

C.1 Stakeholder Engagement Plan

C.2 Rationale for Case Study Scenarios

C.3 Engineering Basis

Technical Note

Subject:	Stakeholder Engagement Plan	To:	Project Management Group, AECOM Project Delivery Group, Client Project Delivery Group, Independent Peer Reviewers
Project:	BEIS Decarbonisation Readiness Requirements Review		
Reference:	60677821-TN-001		
Revision:	2		
Date:	04/03/2022		
Author:	Rhys Williams		

1. Introduction

Delivery of the project will be supported and informed by engagement with different groups of stakeholders. The purpose of this document is to define the different groups, and the objectives, methods and timings of engagement.

2. Project management group

The project management group represents the project managers and directors responsible for the day-to-day management of the project and a forum for regular communication between BEIS and AECOM.

All communications relating to the contract, project progress and schedule, performance and invoicing between the respective project managers will be copied to the project management group members.

The project management group members will be invited to a brief progress update call (no more than 30 minutes) held using MS Teams on a weekly basis on Thursdays at 11:00am, unless agreed otherwise. If considered appropriate, meeting frequency may be extended to fortnightly calls.

Table 1 defines the project management group members.

Table 1. Project management group

Name	Organisation	E-mail Address
Ollie Power (Project Manager)	BEIS	Oliver.Power@beis.gov.uk
Richard Lowe (Project Director)	AECOM	richard.lowe@aecom.com
Andy Cross (Project Manager)	AECOM	andy.cross@aecom.com

3. Project delivery group

3.1 AECOM project delivery group

The AECOM project delivery group represents the engineers and consultants responsible for producing the deliverables on the project. The project delivery group may be expanded as the project progresses to incorporate knowledge and experience from other colleagues within AECOM.

All members of the AECOM project delivery group will be provided with access to the shared project drive and will be notified of issue every deliverable and technical document shared with the client.

The project manager and engineering lead are considered mandatory attendees, while all members of the AECOM project delivery group will be invited to the following meetings:

- Kick-off meeting,
- Technical approach review meeting,

- Interim report review meeting, and
- Final report review meeting.

Table 2 defines the AECOM project delivery group members.

Table 2. AECOM project delivery group

Name	Organisation	E-mail Address
Richard Lowe (Project Director)	AECOM	richard.lowe@aecom.com
Andy Cross (Project Manager)	AECOM	andy.cross@aecom.com
Klim Mackenzie (Engineering Lead)	AECOM	klim.mackenzie@aecom.com
Graeme Cook (Lead Verifier)	AECOM	graeme.cook@aecom.com
Rhys Williams (Internal Reviewer)	AECOM	rhys.williams11@aecom.com
Alistair Barclay	AECOM	alistair.barclay@aecom.com
Reece Crawford	AECOM	reece.crawford@aecom.com
Katie Berry	AECOM	katie.berry@aecom.com
Stephen Florence	AECOM	stephen.florence@aecom.com

3.2 Client project delivery group

The client project delivery group represents the engineers and specialists who will review and comment upon AECOM's deliverables.

All deliverables and technical documents issued to the client will be circulated to the client project delivery group. It is anticipated that the client will consolidate comments and return a single comment response sheet to AECOM.

All members of the client project delivery group will be invited to the following meetings:

- Kick-off meeting,
- Technical approach review meeting,
- Interim report review meeting, and
- Final report review meeting.

Table 3 defines the client project delivery group members.

Table 3. Client project delivery group

Name	Organisation	E-mail Address
Ollie Power	BEIS	oliver.power@beis.gov.uk
William Knight	BEIS	william.knight2@beis.gov.uk
Joey Scarf	BEIS	joey.scarf@beis.gov.uk
Alisha Ali	BEIS	alisha.ali@beis.gov.uk
Rhiannon Phillips	Welsh Government	rhiannon.phillips@gov.wales
Lee Guilfoyle	Welsh Government	lee.guilfoyle@gov.wales

4. Independent peer reviewers

Independent peer reviewers from academia have been appointed to review the technical approach, engineering basis and the summary report.

All deliverables and technical documents issued to the client will also be circulated to the independent peer reviewers.

While comments are welcomed from the IPRs on all documents, the first issue of the following documents are subject to mandatory independent peer review:

- Literature review evidence record sheet (Annex B) – focus on categorisation and validity
- DCR checklist recommendations (Annex C)
- Engineering basis for case studies (Annex D)
- Layout estimation summary (Annex H)
- Interim Summary report

The independent reviewers will attend the following meetings:

- Kick-off meeting,
- Technical approach review meeting, and
- Final report review meeting.

Table 4 defines the independent peer reviewers.

Table 4. Independent peer reviewers

Name	Organisation	E-mail Address
Jon Gibbins	University of Sheffield	j.gibbins@sheffield.ac.uk
Mohamed Pourkashanian	University of Sheffield	m.pourkashanian@sheffield.ac.uk
Paul Fennell	Imperial College London	p.fennell@imperial.ac.uk

5. Examining authority engagement

The examining authorities responsible for assessing the compliance of proposed projects with the current carbon capture readiness requirements and future decarbonisation readiness requirements are considered key stakeholders. Their interest in the project is that they seek to ensure that future guidelines are supported by a strong evidence base and provide a practical and clear means for confirming compliance.

The interim and final reports will be shared with the examining authority stakeholders group. Comments from the examining authority are welcome, however, AECOM request that the examining authority comments be consolidated with the client comments before being shared with AECOM.

Table 5 defines the examining authority stakeholders group

Table 5. Examining authority stakeholders group

Name	Organisation	E-mail Address
John Henderson	Environment Agency	john.henderson@environment-agency.gov.uk
Bruce Bethune	Environment Agency	bruce.bethune@environment-agency.gov.uk
Richard Chase	Environment Agency	richard.chase@environment-agency.gov.uk
Karl Shepherd	Natural Resources Wales	Karl.Shepherd@cyfoethnaturiolcymru.gov.uk

6. Industry engagement

In 2021, BEIS engaged with the industry through a call for evidence with the title “Decarbonisation readiness: call for evidence on the expansion of the 2009 Carbon Capture Readiness requirements”. The draft conclusions of this call for evidence have been shared with the project and will represent a large part of engagement with the industry.

Further engagement with the industry and trade bodies within the scope of this review will be limited by the time available to complete the project. AECOM will review the previous responses, identify the gaps in evidence and any relevant parties not previously contacted, and engage with those organisations only to focus on areas where there is limited evidence.

Table 6 lists the organisations contacted by BEIS in the 2021 call for evidence regarding the expansion of Carbon Capture Readiness requirements.

Table 6. Industry organisations engaged by BEIS in 2021

Organisation	Response received
Blue Phoenix UK	
Stop Portland Waste Incinerator	
United Kingdom Without Incineration Network (UKWIN)	
Bioenergy Infrastructure Group	
Siemens Energy	
Scottish Power	
Flexible Generation Group	
Tees Valley Combined Authority	
Drax Group PLC	
The Association for Decentralised Energy	
Progressive Energy	
Uniper UK	
Sembcorp	
Triton Power	
The Association for Renewable Energy & Clean Technologies (REA)	
AMP Clean Energy	
MCS Charitable Foundation	
InterGen	
RWE Generation	
SSE Thermal	
Environmental Services Association	
Carbon Capture & Storage Association	
Energy UK	
Conrad Energy	
EDF Energy	
Viridor	
Centrica	
Baker Hughes	
CISC (Copenhagen Infrastructure Service Co.)	
Statkraft	
NFU	
BP PLC	

Organisation	Response received
Lynemouth Power	
Scottish Government	
Individuals (3)	

7. Equipment manufacturer engagement

To improve the quality of the evidence base produced as part of this project, and to develop the recommendations for the proposed decarbonisation readiness requirement, AECOM will engage equipment manufacturers to verify their current capability and technology development roadmaps.

The terms of reference for engagement with the different categories of OEMs will be developed separately. The list of manufacturers proposed to be contacted as part of this stakeholder engagement is not intended to be exhaustive but is proposed as a representative range of manufacturers across the various relevant technologies and scales of equipment.

The contribution of the evidence provided by equipment manufacturers to this review will inevitably be limited by the manufacturers' ability and willingness to respond to the Request for Information within the timescales of the project.

7.1 Gas turbine manufacturers

Gas turbine manufacturers will be contacted and invited to respond to the following queries:

- Capability of current product offerings to burn hydrogen,
- Capability of current product offerings to burn ammonia,
- Work involved and potential to retrofit/modify installed gas turbines to fire hydrogen, and
- Technology development road map for burning hydrogen.

Table 7 defines a provisional list of potential gas turbine manufacturers to be contacted.

Table 7. Gas turbine manufacturers

Manufacturer	Gas turbine size range
Siemens	2 to 590 MWe
MHI	40 to 570 MWe
GE	34 to 570 MWe
Ansaldo	80 to 540 MWe
Baker Hughes	5 to 170 Mwe
Solar turbines	3 to 16 Mwe
Centrax	3 to 15 Mwe
MAN	6 to 12 Mwe
Kawasaki	< 3 MWe
OPRA	< 3 MWe
Aurelia	< 1 MWe
Capstone	< 1 MWe
Turbotec	< 1 MWe

7.2 Reciprocating engine manufacturers

Reciprocating engine manufacturers will be contacted and invited to respond to the following queries:

- Capability of current product offerings to burn hydrogen,
- Capability of current product offerings to burn ammonia,
- Work involved and potential to retrofit/modify installed reciprocating engines to fire hydrogen, and
- Technology development road map for burning hydrogen.

Table 8 defines a provisional list of potential gas turbine manufacturers to be contacted.

Table 8. Reciprocating engine manufacturers

Manufacturer	Engine size range
Hyuandai Heavy Industry	1 to 26 MWe
MAN	7 to 20 MWe
Jenbacher	0.2 to 10 MWe
Wartsila	1 to 9 MWe
Caterpillar	0.1 to 5 MWe
MTU	0.2 to 3 MWe
Siemens	0.1 to 2 MWe

7.3 Industrial boiler manufacturers

Industrial boiler manufacturers will be contacted and invited to respond to the following queries:

- Capability of current product offerings to burn hydrogen, and
- Capability of current product offerings to burn ammonia.

Table 9 defines a provisional list of potential industrial boiler manufacturers to be contacted.

Table 9. Industrial boiler manufacturers

Organisation	Boiler types
Macchi	Field erected, pre-fabricated
MHPS	Field erected, pre-fabricated
Babcock Wanson	Pre-fabricated, package
HKB	Pre-fabricated, package
Cochran	Package
Bosch	Package
ICI Caldaie	Package
Byworth	Package

7.4 Electrolysers manufacturers

Electrolyser manufacturers will be contacted and invited to respond to the following queries:

- Capability of current product offerings to produce hydrogen,
- Future developments in capacity.

Table 10 defines a provisional list of potential electrolyser manufacturers to be contacted.

Table 10. Electrolyser manufacturers

Organisation	Electrolyser type
Cummins	Alkaline, PEM
Nel.	Alkaline, PEM
ITM Power	PEM
Siemens Silyzer	PEM
Sunpower	Alkaline, SOEC
CPH2	Membrane free
McPhy	Alkaline

7.5 Carbon capture technology providers

AECOM have recently undertaken significant engagement with carbon capture technology providers as part of the BEIS Next Generation Carbon Capture review. It is intended for this project to utilise the evidence collected through the course of that project to update the existing CCS body of evidence. Where gaps are identified AECOM will engage with carbon capture technology providers as necessary.

Table 11 defines a list of the technology providers previously contacted.

Table 11. Carbon capture technology providers

Organisation	Capture technology
Aker Carbon Capture	Solvent based
Mitsubishi Heavy Industries	Solvent based
Shell Cansolv	Solvent based
Fluor	Solvent based
Carbon Clean	Solvent based
C-Capture	Solvent based
Compact Carbon Capture	Solvent on rotating packed bed
Svante	Solid adsorbent on rotating packed bed
Fuel Cell Energy	Fuel Cell
Air Liquide	Cryogenic
Calix	Indirect calcination for cement production
CO_2 Capsol	Carbonation
Origen Power	Carbonation
Carbon8 Systems	Carbonation
Baker Hughes	Chilled ammonia
Membrane Technology and Research	Membranes
NET Power	Allam-Fetvedt cycle

Appendix A Document Log

A.1 Document History

Rev.	Issued Date	Details	Author	Checker	Lead Verifier	Approver
1	09/02/2022	Issued for comment	Rhys Williams	Andy Cross	Graeme Cook	Andy Cross
2	08/04/2022					

A.2 Document Revisions

Rev.	Section	Revisions/Remarks
1	All	First issue, with HOLDS
2	All	Updated

Technical Note

Subject:	Rationale for case study scenarios	To:	Project Management Group, AECOM Project Delivery Group, Client Project Delivery Group, Independent Peer Reviewers
Project:	BEIS Decarbonisation Readiness Requirements Review		
Reference:	60677821-TN-002		
Revision:	2		
Date:	30/06/2022		
Author:	Klim MacKenzie		

1. Introduction

This document defines the initial set of case studies proposed by AECOM as discussed at the project inception meeting and Technical Approach Review. The purpose of this document is to define the rationale and decision-making process for the final selection of case studies for both lots.

2. Initial Case Study Basis

2.1 Rationale for Lot 1 Hydrogen Readiness Case Studies

The initial set of case studies presented at the project inception meeting is shown below in Table 1.

Table 1. Lot 1 Hydrogen Readiness initial proposed case studies

#	Combustion technology	Sizing Basis	Small	Medium	Large
1	CCGT (Utility Scale)	Plant nominal gross power output	220 MWe	450 MWe	805 MWe
2	CCGT (CHP application)	GT nominal gross power output	14 MWe	35 MWe	60 MWe
3	OCGT (small scale GTs)	GT nominal gross power output	4 MWe	6 MWe	10 MWe
4	Boiler (CHP)	Boiler Output gross power output	35 MWth	65 MWth	150 MWth
5	Reciprocating Engine	Engine nominal gross power output	4.5 MWe	10 MWe	22.5 MWe (5 x 4.5 MWe units)

Source: Notes of BES DCR Kick-off meeting 2022-02-04

Rationale for CCGT (utility scale) basis: Large represents the largest size of latest H class turbines, similar to that proposed on major UK projects. Medium is representative of the bulk of gas turbines (F class/GT26 turbines) installed in the UK since 2010 and most likely turbines to be considered for retrofits. Small is not a size of plant deployed in the UK at present and is particularly small but was selected to provide a third point on the curve to enable interpolation across a broad range.

Rationale for CCGT (CHP application): used to provide a broad range of sizes based on AECOM's experience of GT CHP plants worldwide. In addition, multiple OEMs market gas turbines in small and large size as 100% hydrogen ready today.

Small scale OCGTs: while not particularly widely utilised, include a number of these smaller units cited as being capable of 100% hydrogen ready. They are also of a size whereby the hydrogen demand is close to that of the current largest electrolysers, whereas for larger turbines the hydrogen demand is orders of magnitude greater than the existing largest green hydrogen plants.

Reciprocating engine: sizes are based on broad range of engine sizes widely available and in service. While units smaller than 4.5MWe are possible, the application of CCS or decarbonisation is more likely to happen on sites where there are greater emission reductions to be achieved.

The table has utilised electrical power output for many size classifications similar to the 2009 CCR guidance.

2.2 Rationale for Lot 2 Carbon Capture Case Studies

The initial set of case studies presented at the project inception meeting is shown below in Table 2.

Table 2. Lot 1 Carbon Capture Readiness initial proposed case studies

#	Combustion technology	Sizing Basis	Small	Medium	Large
1	CCGT (Utility Scale)	Plant nominal gross power output	220 MWe	450 MWe	910 MWe
2	CCGT (CHP application)	GT nominal gross power output	14 MWe	35 MWe	60 MWe
3	Boiler (EfW)	Plant nominal gross power output	20 MWe	45 MWe	80 MWe
4	Boiler (Biomass)	Plant nominal gross power output	35 MWe	65 MWe	120 MWe
5	Reciprocating Engine	Engine nominal gross power output	4.5 MWe	10 MWe	22.5 MWe (5 x 4.5 MWe units)

Rationale for CCGT (utility scale) basis: Large represents the largest size of latest H class turbines, similar to that proposed on major UK projects. Medium is representative of the bulk of gas turbines (F class/GT26 turbines) installed in the UK since 2010 and most likely turbines to be considered for retrofits. Small is not a size of plant deployed in the UK at present and is particularly small but was selected to provide a third point on the curve to enable interpolation across a broad range.

Rationale for CCGT (CHP application): used to provide a broad range of sizes based on AECOM's experience of GT CHP plants worldwide. In addition, multiple OEMs market gas turbines in small and large size as 100% hydrogen ready today.

Boiler: cases are based on providing a broad range to support interpolation with minimum and maximum values guided by the size of existing plants in the UK as per the 2021 Dukes report. Drax Biomass is an outlier in terms of size and scale of biomass plants in the UK with a total net output of 2.6GWe. The other reason for its omission at this stage from a footprint and cost estimate as part of this study is that there is significant information in the public domain on CCS at the site due to the on-going DCO application.

Reciprocating engine: sizes are based on broad range of engine sizes widely available and in service. While units smaller than 4.5MWe are possible, the application of CCS or decarbonisation is more likely to happen on sites where there are greater emission reductions to be achieved.

The table has utilised electrical power output for many size classifications similar to the 2009 CCR guidance.

2.3 Assessment of case study spread and UK power generation industry

The proposed case studies were selected to represent a distribution across a broad range of emitter sizes and support interpolation between specific case studies, see Figure 1 and Figure 2 for a spread in terms of CO2 flows and energy demand.

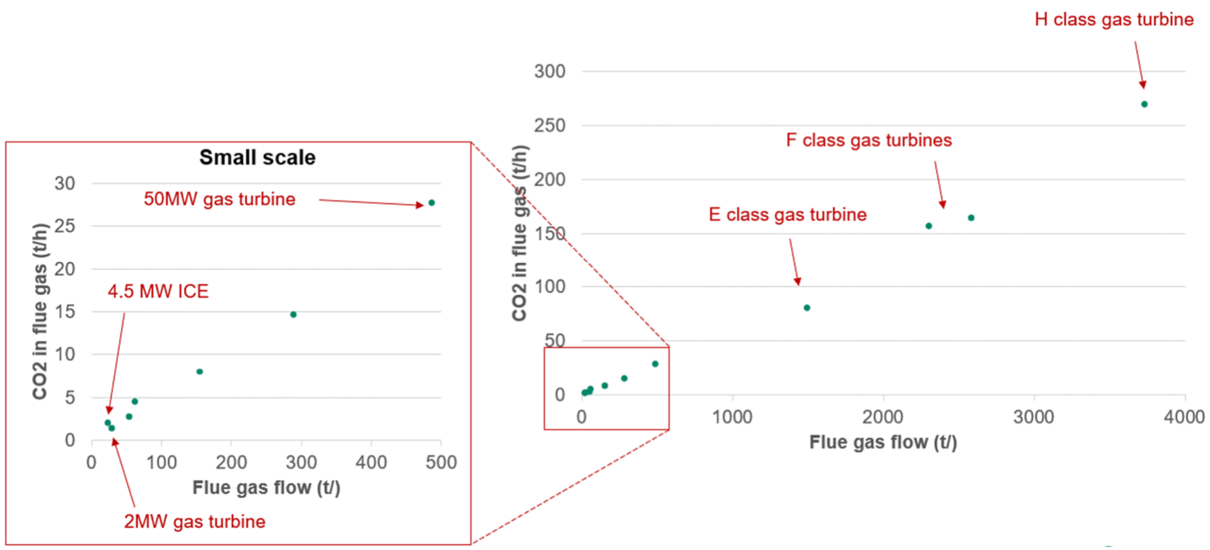

Figure 1. Case study spread in terms of flue gas and CO2 flows

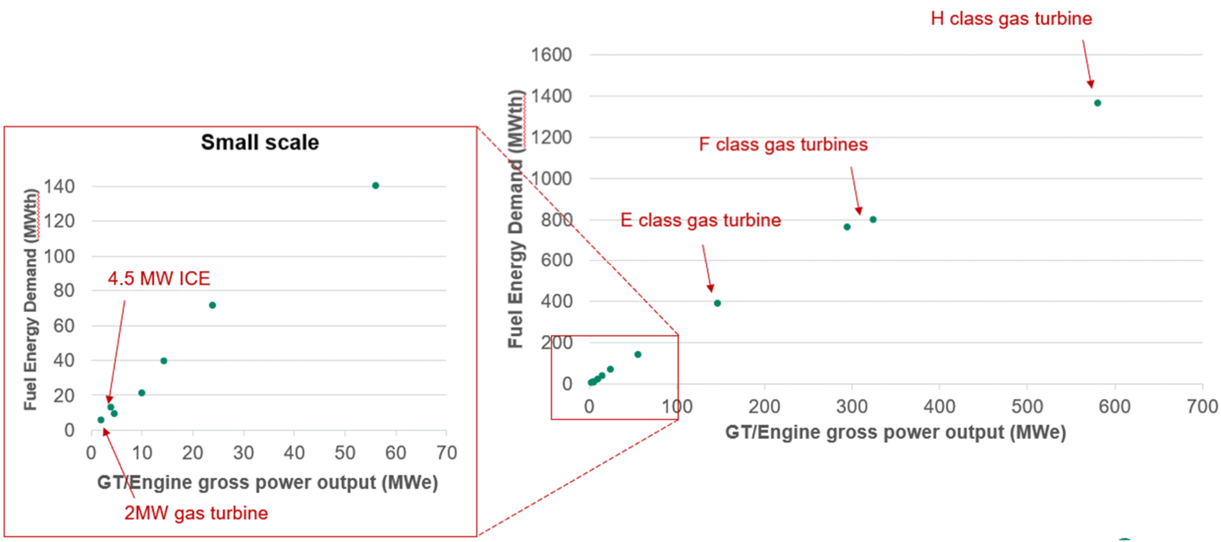

Figure 2. Case study spread in terms of fuel energy demand

2.4 UK CCGT size distribution

All CCGTs in the UK built since 2015 have train sizes between 425MWe and 475MWe. The distribution of proposed plants, in comparison, lies between 575MWe and 975MWe, with a subset between 860MWe and 910MWe being actively progressed through planning. The recommendation is therefore for 910MWe to cover new-build H Class CCGT, 450MWe to cover the existing fleet dominated by F Class CCGT, and a third data point at approximately 220MWe to provide interpolation (based on E Class technology). See Figure 3.

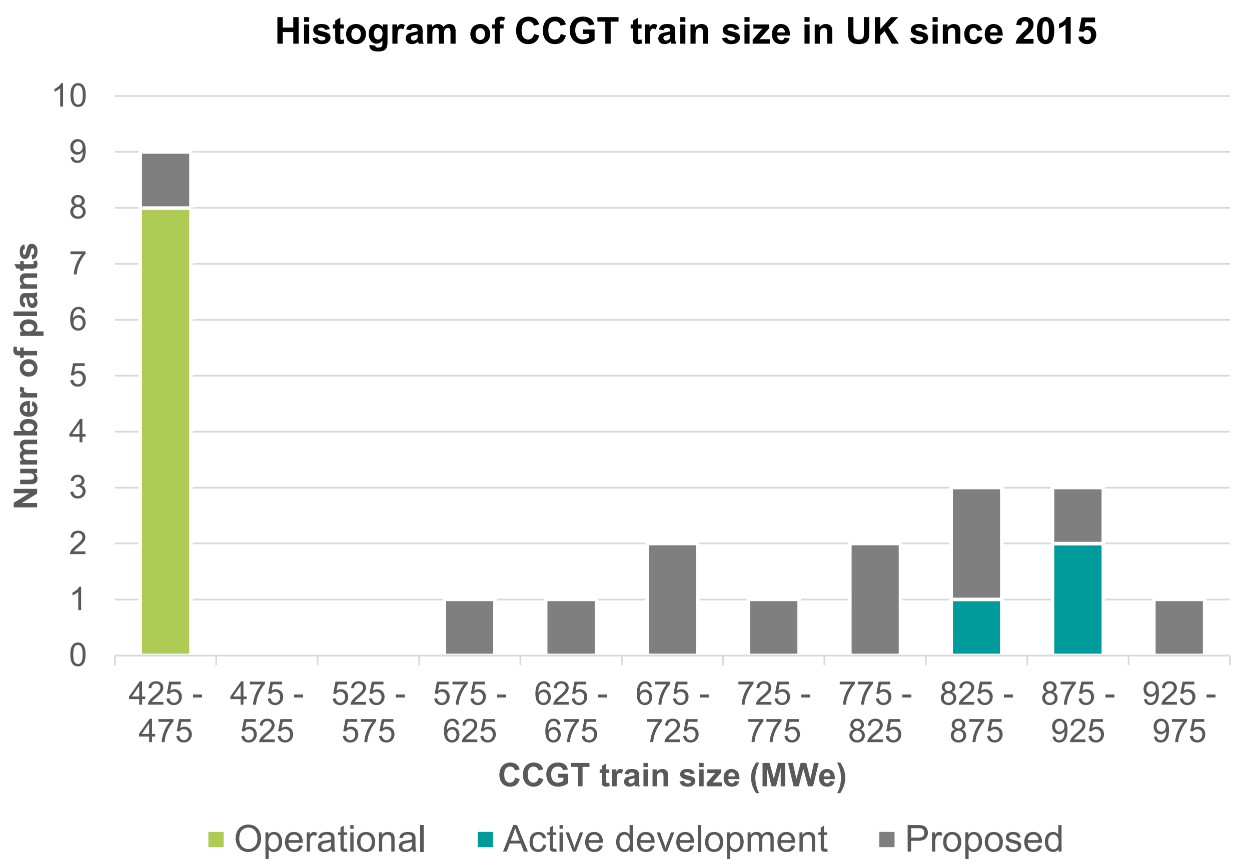

Figure 3. Histogram of CCGT train size in UK since 2015

2.5 UK OCGT size distribution

All OCGTS built in the UK have train sizes less than 150MWe. In comparison, the 10 GT based peaking plants proposed since 2015 have all been proposed at 299MW, at least 6 of which have been awarded or are still live within the PINS process. The 299MW sizing for modern OCGT in the UK appears to be driven by the 2009 Carbon Capture Readiness regulations as this block size does not appear elsewhere in the world.

GTs in the 10-100MW range are well-covered by the CCGT/CHP scope, therefore, AECOM proposed focussing on recent developments and the smaller end of the spectrum <10MW. however, this excludes micro-turbines, see Figure 4.

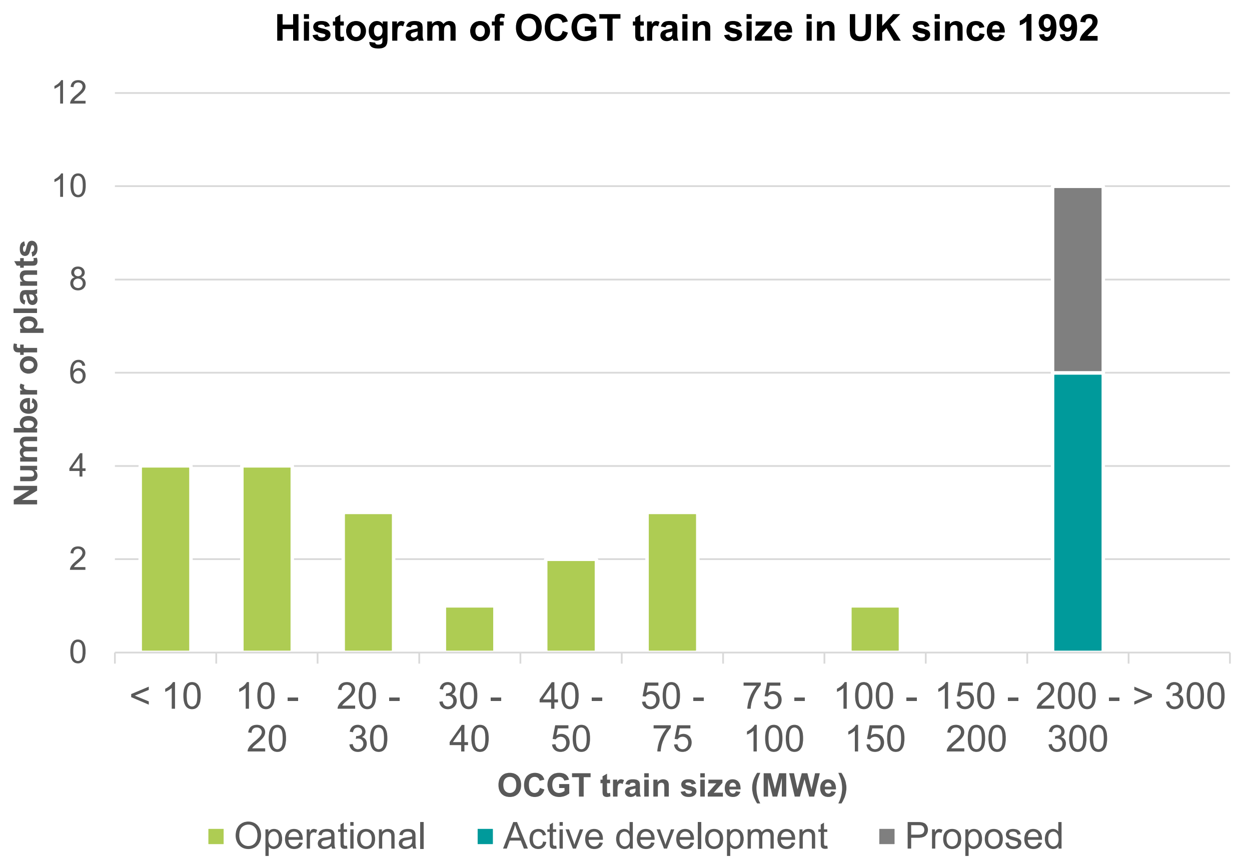

Figure 4. Histogram of OCGT train size in UK since 1992

2.6 UK biomass plant size distribution

The majority of UK biomass plant is below 50MWe with two notable exceptions: Lynemouth and Drax, both of which are relatively unique in their scale. Further, Drax already has a well-publicised carbon capture programme as part of the East Coast Cluster. Therefore, the focus for the study was proposed to consider plants at the 35MWe and 65MWe scale to span the 50MW centre-line, as well as one larger case to represent wider roll-out of BECCS. See Figure 5.

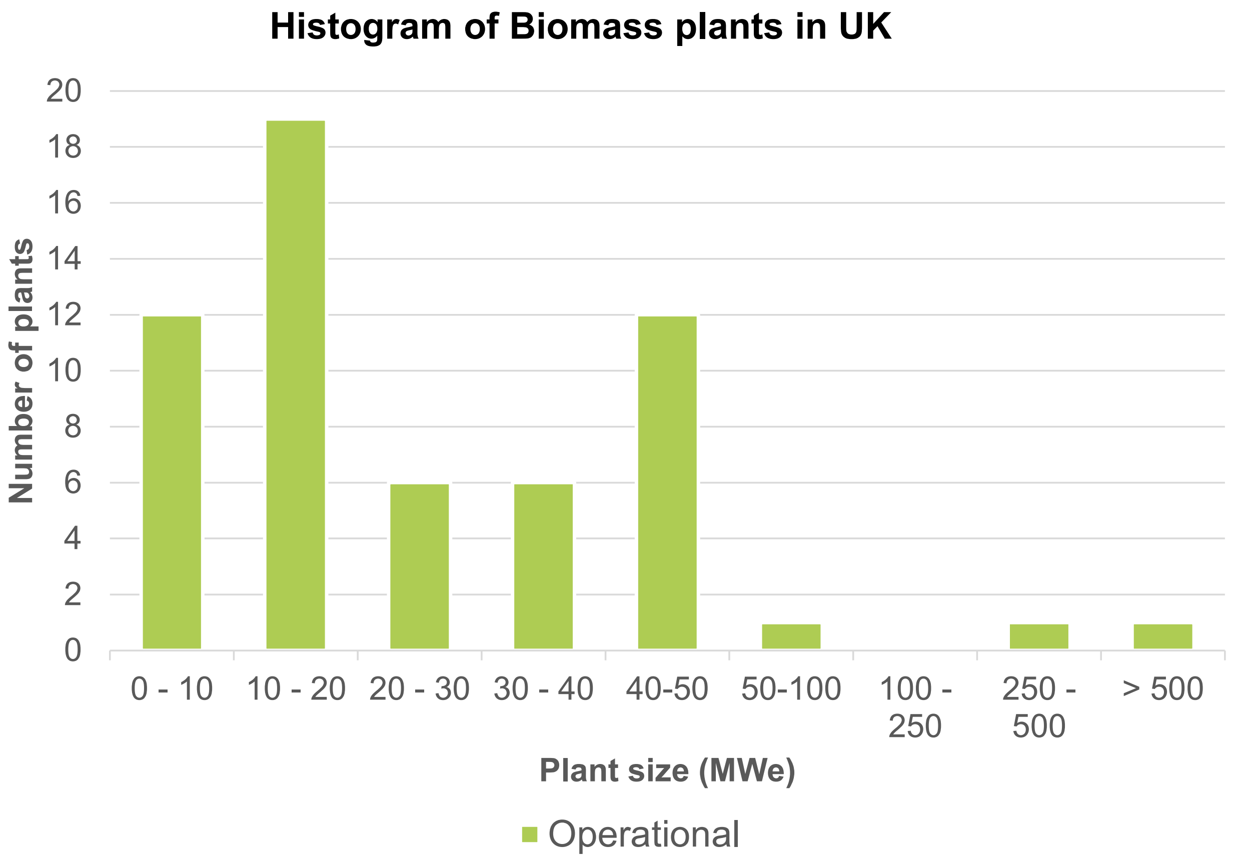

Figure 5. Histogram of biomass plants in the UK

2.7 UK EfW plant size distribution

The selection of EfW plants proposed for the case studies was chosen consistent with the peaks around 20MWe, 45MWe and 80MWe for existing EfW plant in the UK, see Figure 6

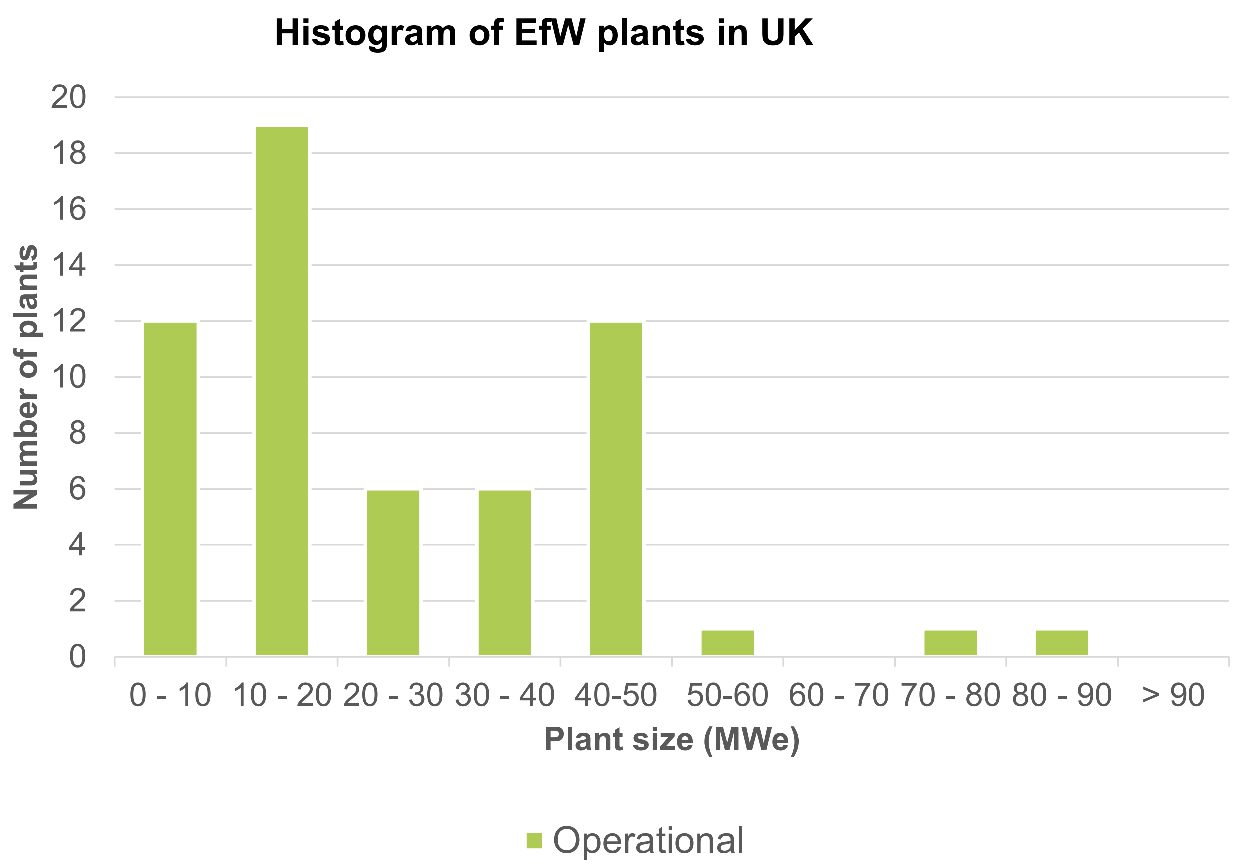

Figure 6. Histogram of EfW plant in the UK

3. Selected Case Studies Basis

The case studies were updated following the Technical Approach Review with BEIS, the Independent Reviewers and the Regulators. The adopted case studies for Lot 1 are shown in Table 3, following request from the EA to consider 2MWe and 4MWe units, as well as the 299MWe case to represent the current set of projects live with PINS. In addition, the reciprocating engine case studies were changed from the original basis.

Table 3. Lot 1 Hydrogen Readiness initial proposed case studies

#	Combustion technology	Sizing Basis	Small	Medium	Large
1	CCGT (Utility Scale)	Plant nominal gross power output	220 MWe	450 MWe	805 MWe
2	CCGT (CHP application)	GT nominal gross power output	14 MWe	35 MWe	60 MWe
3	OCGT (small scale GTs)	GT nominal gross power output	~~4 MWe~~ 2 MWe	~~6 MWe~~ 4 MWe	~~10 MWe~~ 299 MWe
4	Boiler (CHP)	Boiler Output gross power output	35 MWth	65 MWth	150 MWth
5	Reciprocating Engine	Engine nominal gross power output	4.5 MWe	~~10 MWe~~ 12.5 MWe (5 x 2.4 MWe units)	~~22.5 MWe (5 x 4.5 MWe units)~~ 50 MWe (5 x 10MWe units)

For the carbon capture case studies, the EA requested two OCGT-scale units to be added to the scope of the review, summarised in Table 4, as well as a change to the sizes of reciprocating engines studied. These changes were adopted into the selected case studies for the review.

Table 4. Lot 1 Carbon Capture Readiness initial proposed case studies

#	Combustion technology	Sizing Basis	Small	Medium	Large
1	CCGT (Utility Scale)	Plant nominal gross power output	220 MWe	450 MWe	910 MWe
2	OCGT (Utility Scale)	Plant nominal gross power output	145 MWe	290 MWe	-
3	CCGT (CHP application)	GT nominal gross power output	14 MWe	35 MWe	60 MWe
4	Boiler (EfW)	Plant nominal gross power output	20 MWe	45 MWe	80 MWe
5	Boiler (Biomass)	Plant nominal gross power output	35 MWe	65 MWe	120 MWe
6	Reciprocating Engine	Engine nominal gross power output	4.5 MWe	~~10 MWe~~ 12.5 MWe (5 x 2.4 MWe units)	~~22.5 MWe (5 x 4.5 MWe units)~~ 50 MWe (5 x 10MWe units)

Appendix A Document Log

A.1 Document History

Rev.	Issued Date	Details	Author	Checker	Lead Verifier	Approver
1	16/05/2022	Issued for comment	Klim MacKenzie	Andy Cross	Graeme Cook	Andy Cross
2	30/06/2022	Revised	Klim MacKenzie	Andy Cross	Graeme Cook	Andy Cross

A.2 Document Revisions

Rev.	Section	Revisions/Remarks
1	All	First issue
2	H2R H Class	Revised size of H Class CCGT used for H2R lot consistent with data availability for H Class units with hydrogen (CC H Class size unchanged)

Technical Note

Subject:	Engineering Basis – H2	To:	Project Management Group, AECOM Project Delivery Group, Client Project Delivery Group, Independent Peer Reviewers
Project:	BEIS Decarbonisation Readiness Requirements Review		
Reference:	60677821-TN-003		
Revision:	2		
Date:	30/06/2022		
Author:	Rhys Williams		

Table of Contents

Introduction

1.1 Document Purpose

This document details the engineering design basis for the case studies supporting the Decarbonisation Readiness Requirements Review project.

These case studies focus on the fuel switching from natural gas to hydrogen on a range of different configurations and sizes of power plants.

1.2 Project Overview

Since 2009, new build combustion power plants sized over 300MWe in England and Wales have been required to demonstrate they could retrofit carbon capture and storage (CCS) in order to decarbonise. This policy has been known to date as 'Carbon Capture Readiness' (CCR).

In 2009, detailed guidance was produced to support industry and BEIS in assessing the CCR requirements. Due to evolution of gas turbine size and efficiency, variable load profiles for fossil fuel plants, and to recognise the changing landscape of carbon capture and decarbonisation technologies, this guidance needs to be updated, as plants below 300MWe and new plant types (e.g. combined heat and power, energy from waste and biomass) will now be assessed for carbon capture readiness. The guidance document will also be expanded to cover hydrogen readiness as a means of decarbonisation.

As part of the expansion, BEIS are renaming the policy to 'Decarbonisation Readiness'. In order to update the guidance BEIS have commissioned two technical studies to update and expand the underpinning evidence base that was used to develop the guidance documents.

The technical studies are:

1. Lot 1 – Hydrogen readiness
2. Lot 2 – Carbon capture readiness

This document is intended to define the design basis for engineering calculations as part of the '**Lot 1 - Hydrogen readiness'** technical study.

1.3 Case Study Overview

1.3.1 Case Study Aim

The aim of this project is to develop an evidence base that is used to define the requirements for demonstrating decarbonisation readiness and inform guidance.

BEIS require hydrogen readiness be demonstrated through the five different assessments below:

1. that sufficient space is available on or near the site to accommodate any equipment necessary to facilitate hydrogen conversion;
2. that it will be technically feasible to convert the site to 100% hydrogen-firing;
3. that the site's location enables the transport of hydrogen to the site and/or that hydrogen can be produced and potentially stored at the site;
4. that it is likely to be economically feasible, within the power station's lifetime, to convert to hydrogen combustion; and
5. that the plant will be technically capable of firing a blend of hydrogen on the day it is put into operation.

The purpose of the case studies is to provide an evidence base that can be used by examiners during the application process to determine if the acceptance criteria for assessments 1 and 4 above have been addressed appropriately by developers.

1.3.2 Case Study Definition

Table 1 defines the configurations and sizes of plant that will be subject to case studies.

The proposed configurations cover a broad range of hydrogen demands and technologies. AECOM will provide the CO_2 avoided, fuel energy demand and Hydrogen demand for each configuration to allow for interpolation of plants of different sizes.

Table 1. Case Study Definition

Combustion technology	Sizing Basis	Small	Medium	Large
CCGT (Utility Scale)	Plant nominal gross power output	220 MWe	450 MWe	805 MWe
OCGT (Utility Scale)	Plant nominal gross power output	2 MWe	4 MWe	290 MWe
CCGT (CHP application)	GT nominal gross power output	14 MWe	35 MWe	60 MWe
Boiler (CHP)	Boiler Output	10 MWth	65 MWth	150 MWth
Reciprocating Engine	Engine nominal gross power output	1 MWe	12.5 MWe (5 x 2.4 MWe units)	50 MWe (5 x 10 MWe units)

1.3.3 Case Study Methodology

AECOM propose to use the Thermoflow v30.0 software to undertake process simulation, development of heat and material balances and majority of cost-estimation.

Thermoflow is an established software suite that has been used in the power industry for over 30 years for fossil fuel, EfW and renewables. In addition to process simulation capability, Thermoflow is supplied with a cost simulation add-on known as PEACE (Plant Engineering And Construction Estimator). In addition to providing cost estimates, PEACE completes preliminary equipment sizing and design to generate indicative general arrangement drawings.

The approach to the case studies proposed is:

- Develop counterfactual (natural gas fired) simulation model
- Verify counterfactual model output against recent experience and publicly available data
- Update counterfactual model to fire hydrogen
- Extract performance output data and cost outputs from the simulation and PEACE
- Verify cost estimate data and supplement with recent AECOM experience and information received from vendors
- Complete economic assessment
- In parallel to the economic assessment, preliminary equipment sizing and equipment specifications will be extracted to generate the layouts and plant footprint estimates.

The performance, cost and layout conclusions will be summarised and included in the summary report.

Note that the case studies are based on fully hydrogen fired solutions, the implications of hydrogen-natural gas blends on the conclusions of the case studies are to be discussed in the summary report.

2. Definitions and Acronyms

2.1 Definitions

Table 2 defines the terms used within this document.

Table 2. Acronyms utilised on this project

Term	Description
Power island	Equipment associated with power production from the combustion unit/prime mover through to the power plant stack
Hydrogen import infrastructure	Equipment associated with the import of hydrogen to the site, including metering, pressure control, natural gas blending, and combustion gas diluent packages.
Utilities units	Equipment associated with cooling, water treatment, waste water treatment, nitrogen and instrument air systems
Balance of plant	Equipment, electrical equipment and buildings not included in any of the above terms

AECOM

2.2 Acronyms

Table 3 defines the acronyms and abbreviations used within this document.

Table 3. Acronyms utilised on this project

Acronym	Description
AACE	American Association of Cost Engineers
BoD	Basis of Design
BEDD	Basic Engineering Design Data
BFW	Boiler Feed Water
CCGT	Combined Cycle Gas Turbine (Gas Turbine + Steam Turbine)
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CWS	Cooling Water Supply
CWR	Cooling Water Return (discharge in the case of once-through system)
GT	Gas Turbine
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
LHV	Lower Heating Value
LP	Low Pressure
MPI	Major Plant Items
NOx	Nitrogen oxides
OEM	Original Equipment Manufacturer
OM	Operating Mode
RH	Relative Humidity
SCR	Selective Catalytic Reduction
ST	Steam Turbine
WN	Wobbe Number

3. Units of Measure

Table 4 defines the acronyms and abbreviations used within this document.

Table 4. Project units of measure

Parameter	Measuring Unit	Abbreviation
Absolute Viscosity	Centipoise	cP
Concentration (vol.)	Parts per million by volume, parts per million by volume - dry basis (i.e. excluding diluting contribution of water molecules)	ppmv, ppmvd
Concentration (mass)	Percent by weight (mass), percent by mol	%wt
Concentration (molar)	Percent by weight (mass), percent by mol	%mol
Density	Kilogram per cubic meter	kg/m^3
Exported Electricity	Megajoules	MJ
Flowrate (Mass)	Kilogram per second, million metric tons per annum	kg/s, MTPA
Heat transfer rate	Kilowatt thermal, Megawatt thermal	kW.th, MW.th
Length	Meter	m
Mass	Kilograms or metric tons	kg, t
Power	Gigawatt, megawatt or kilowatt	GW, MW, kW
Pressure	Bar gauge, bar atmosphere, millibar	barg, bara, mbar
Temperature	Degree Celsius	ºC
Volume	Cubic meter	m^3
Volume flowrate	Cubic meter per hour, Normal cubic meter per hour (at 20°C and 1.01325bara)	m^3/h, Nm^3/hr
Mass flowrate	Metric tons per hour or kilograms per second	t/h, kg/s

4. Process Design Basis

4.1 Ambient Conditions

The reference conditions to be used in the study are summarised in Table 5 with International Standards Organization (ISO) conditions (ISO18888:2017) assumed for the site for this study.

Table 5. Reference conditions

Parameter	Value
Temperature, °C	15
Pressure, bara	1.013
Relative Humidity, %RH	60

4.2 Hydrogen Supply Specification

The Hydrogen supply specification is given in Table 6 for the pipeline supplied gas to the site and is based upon that proposed in IGEM/H/1 Appendix 4.

Table 6. Hydrogen Supply Specification

Parameter	Value
Hydrogen content, %mol	> 98 %
Oxygen content, %mol	< 0.2 %
Sum of methane, CO_2 and total hydrocarbons, %mol	< 1 %
Sum of argon, nitrogen and helium, %mol	< 2 %
Carbon Monoxide (CO), ppmv	< 20
Hydrogen Sulphide (H_2S), ppmv	< 3.5
Total Sulphur (S), ppmv	< 35
Hydrocarbon dewpoint, °C	< -2
Water dewpoint, °C	< -10
Wobbe number range, MJ m^{-3} (at 15°C and 1.01325 bara)	42 - 46

The conditions assumed for the purposes of concept design are defined in Table 7. Three supply pressure levels have been assumed and set at levels similar to the different levels of the natural gas distribution networks. The cut-off flow for each pressure level is equivalent to the flow through a nominal 12” pipe with an effective gas velocity of 20 m/s.

Table 7. Hydrogen Supply Reference Conditions

Parameter	Value		
Site hydrogen demand, tph	≤ 0.5	0.5 < M ≤ 8	> 8
Pressure, barg	7	17	60
Temperature, °C	10	10	10
Hydrogen content, %mol	98 %	98 %	98 %
Carbon dioxide content, %mol	0.3 %	0.3 %	0.3 %
Nitrogen content, % mol	1.5 %	1.5 %	1.5 %
Oxygen content, %mol	0.2 %	0.2 %	0.2 %

4.3 Export Power Specification

The export conditions assumed for the purposes of concept design are defined in Table 7. Four export voltage levels have been assumed in order to size the export switchgear and infrastructure.

Table 8. Export Power Reference Conditions

Parameter	Value				
Power plant nominal capacity, MW	≤ 10	10 < M ≤ 50	50 < M ≤ 100	100 < M ≤ 500	> 500
Export Voltage Level, kV	6.6	11	132	275	400

4.4 Utility Specifications

The plant shall be provided with the following utilities:

- Cooling water
- Plant treated make-up water
- Electricity

4.4.1 Cooling Water

Heat rejection for the plant shall be by a series of cooling towers. The design duty of the cooling water system is to be determined from the Heat and Material Balance assessment. The operating and design conditions of the cooling water network are shown in Table 9. The general design philosophy for equipment will adjust cooling water flow to maintain 10°C temperature rise across exchangers and within the cooling tower an approach temperature of 4.5°C to wet bulb temperature.

For the purpose of this study cooling is assumed to be provided by mechanical draft cooling tower and that a desalinated water supply for make-up is readily available.

Table 9. Cooling water conditions

Cooling Water Condition	Value
Cooling Water Supply (CWS), °C	15
Cooling Water Return (CWR) °C	25

4.4.2 Plant Treated Make-up Water

Power plants with a steam cycle will typically include a water treatment plant to produce BFW. A typical minimum specification for the make-up water is shown in Table 10 below.

Table 10. Make-up water quality typical minimum specification

Parameter	Value
Chlorides, ppmw	<2.0
Total Dissolved Solids, ppmw	<50
Total Hardness, ppmw	<2.0
Sodium/Potassium, ppmw	<25
Iron, ppmw	<1.0

4.4.3 Electricity

Each technology/configuration will have an optimum location for extraction of electricity integration into the power islands electrical network. The tie-in for power for hydrogen infrastructure is likely to be minimal (unless on-site production is required) and shall be identified on a case-by-case basis.

5. Equipment Design Criteria

5.1 Design Margin

A design margin of 20% will be applied to the sizing flow rates for pumps, and a margin of 20% will be applied to area calculated for heat exchangers.

Note that 20% represents a relatively large over-design margin compared to normal design practice, however, it is considered reasonable for the Case Studies which shall only comprise a single H&MB case at ISO conditions.

5.2 Sparing Philosophy

The sparing philosophy for critical and high value equipment is specified in Section 5.3 , however, the following general principles will be applied for sparing of all other equipment on the plant:

- Static equipment will not be sparred
- Heat exchangers will not be sparred
- Pumps will require a minimum of N+1
- Compressors will require a minimum of N+1

5.3 Equipment Specific Criteria

5.3.1 Heat Exchanger Design Basis

Indicative approach temperatures and heat transfer performance for heat exchangers for preliminary sizing is to be per Table 11 for the shell-and-tube and plate-and-frame types. The values stated offer a realistic preliminary design basis for shell-and-tube and plate-and-frame heat exchanger types.

Table 11. Heat exchanger specification parameters

Heat Exchanger Parameter	Value
F_t correction factor	>0.8
Temperature Approach for Shell-and-tube Type, °C,	10
Temperature Approach for Plate-and-frame Type, °C	5

5.3.2 Pump Design Basis

Preliminary pump duty estimates based on shaft work required with corrections for efficiencies are shown in Table 12.

Table 12. Pump efficiencies

Pump Parameter	Value
Mechanical efficiency, 0 – 2kW	50%
Mechanical efficiency, 2 – 200 kW	65%
Mechanical efficiency, 200 – 1000 kW	75%
Mechanical efficiency, >1000 kW	85%
Electrical efficiency all pumps, typical	99%

5.3.3 Cooling Tower Design Basis

The design parameters for sizing of the cooling tower package (note that for the H&MB less severe conditions are assumed) are presented in Table 13.

Table 13. Cooling tower parameters

Cooling Tower Parameter	Value
Cooling tower type	Mechanical, induced, plume abated
Cooling tower cell sparing	N+1
Approach to wet-bulb temperature, °C	4.5
Design ambient wet-bulb, °C	25
Cooling water return temperature design purposes, °C	29.5
Cooling water supply temperature design temperature, °C	19.5
Cycles of concentration	5

Appendix A Document Log

A.1 Document History

Rev.	Issued Date	Details	Author	Checker	Lead Verifier	Approver
1	04/03/2022	Issued for comment	Rhys Williams	Klim MacKenzie	Graeme Cook	Andy Cross
2	30/06/2022	Revised	Klim MacKenzie	Andy Cross	Graeme Cook	Andy Cross

A.2 Document Revisions

Rev.	Section	Revisions/Remarks
1	All	First issue
2	H Class CCGT Size	Revised size of large CCGT case study consistent with simulation basis and data availability

Appendix D Concept Design Summaries

D.1 Quality, Impact and Risk Definitions

The below tables provide a summary of how each assumption in the technoeconomic analysis was evaluated by assessing the quality of the data source and the impact of the assumption on model outputs before being translated into risk ratings.

Rating	Definition	Grade	Comments
Quality	This assessed the certainty and/or robustness of a data source. If that data is manipulated or transformed in some way, the quality decreases. (e.g. ±50% would have a low quality rating.	High	The value is based on real data and transformations are minimal or robust. The data is current and there is a narrow confidence interval.
		Medium	Value is based on limited data, but reasoning is robust. There has been significant manipulation to the data and the confidence interval is wide.
		Low	There is either no data source or an unreliable data source. Quality rating may also be low if a robust data source us used but the data is likely to change significantly over the model period.
Impact	This assesses the sensitivity of the model outputs to variations in inputs. Rating should reflect the relative change in output when input is changed.	Low	A change in input value has a negligible impact on model outputs.
		Medium	A change in input value has some impact on model outputs.
		High	A change in input value has some impact on model outputs.
Risk	This assesses which assumptions need to be highlighted.	Low	Assumption has low impact and source is of good quality. Very little can be done to improve.
		Medium	Assumptions has medium impact on model outputs. Changes would affect results but only slightly.
		High	Assumption has high impact on model outputs.
		Very High	Changes have the potential to affect results significantly.

The matrix provided below displays how the overall rating was determined from each of the individual ratings.

Risk Rating		Impact Rating		
		Low	Medium	High
Quality Rating	High	Low	Medium	High
	Medium	Low	High	Very High
	Low	Medium	Very High	Very High

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