# Hydrogen to Power Costs and Barriers

**CLIENT:** Department for Energy Security & Net Zero

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# 1 Glossary

**Balance of Plant (BoP):** All supporting systems and infrastructure required for plant operation, excluding the core generation equipment (e.g. turbine or engine). This includes fuel handling systems, air intake and exhaust systems, safety systems, and the physical structures that house plant equipment, such as concrete foundations, buildings, and enclosures.

**Dry Low Emissions (DLE) / Dry Low $NO_x$ (DLN):** Turbine combustion system that premixes fuel and air to limit flame temperature and control $NO_x$ emissions without water or steam injection. Widely used in modern natural gasfired turbines. Development of this technology for high hydrogen blends is ongoing due to challenges with flame stability and $NO_x$ formation. This technology is not applicable for reciprocating engines.

**Dual fuel**: Turbine or engine system capable of operating on a blend of hydrogen and a secondary fuel, typically natural gas, up to a defined hydrogen limit defined by the system's "Hydrogen Capability" (see below). Allows flexible operation across all blend levels within the defined ranges, without hardware modification.

**EPC:** Engineering, Procurement, and Construction (EPC) refers to a common form of contracting arrangement in the construction and energy sectors where a single contractor is responsible for the detailed engineering design of a project, procuring all the necessary equipment and materials, and managing the construction process to deliver a fully operational facility

**Hydrogen-capable:** A turbine or engine designed to operate on hydrogen blends up to a specified volumetric percentage blend limit without requiring hardware changes. The system's "Hydrogen Capability" is defined by this maximum allowable hydrogen blend. All installed Balance of Plant (BoP) components must also be compatible with the stated hydrogen blend limit to ensure safe and reliable operation.

**Hydrogen-ready**: A descriptor for systems designed to be upgraded in the future to operate on up to 100 vol% hydrogen with minimal hardware modifications. The definition of "hydrogen-ready" typically varies somewhat between manufacturers, but generally refers to power plants where all Balance of Plant (BoP) component (e.g. pipes, valves, and fittings) are compatible with 100% hydrogen. Furthermore, the core equipment (e.g., turbine or engine) is designed to enable straightforward replacement or retrofitting of combustion components with hydrogen-compatible versions, once such technologies are commercially available for the specific model or when hydrogen supply is available at the site.

**OEM:** Original Equipment Manufacturer

**Power derate:** A reduction in maximum power output relative to the original rated capacity, typically achieved by limiting fuel flow or adjusting combustion parameters such as air-fuel ratio and combustion staging. Derating is commonly applied when adapting turbines and engines originally designed for natural gas to operate on hydrogen, in order to maintain combustion stability and control NOX emissions while preserving key performance metrics such as fuel efficiency and ramp rates. By contrast, fuel efficiency is the conversion of chemical energy of the fuel (natural gas, hydrogen) to electrical energy – which can be above 40% (LHV) for 'state of the art' OCGT.

**Wet Low Emissions (WLE) / Wet Low $NO_x$ (WLN):** Turbine combustion system that injects water or steam into the flame zone to lower combustion temperature and reduce $NO_x$ emissions. Enables

100 vol% hydrogen firing but typically with reduced efficiency relative to DLE systems, due to thermal losses and additional power consumption. Not applicable to reciprocating engines.

**Repowering:** Repowering is the process of replacing or extensively upgrading major power plant components such as gas turbines, reciprocating engines, and associated systems, resulting in a newbuild-equivalent facility on the existing site.

**Retrofit:** Retrofit refers to the modification of an existing gas-fired plant to burn a specified hydrogen–natural gas blend up to 100% hydrogen. Modifications will vary according to the characteristics of the existing site, however, typical minimum requirements include upgrading fuel delivery and combustion systems and adapting control and safety systems

**Sequential combustion:** Two-stage combustion system used in certain large-frame gas turbines, with primary and secondary combustion zones to enable high efficiency and low emissions at elevated firing temperatures. Under evaluation for adaptation to 100 vol% hydrogen firing in existing natural gas turbine architectures. Not applicable to reciprocating engines.

**T&S:** Transport and Storage; referring to the infrastructure requirements such as pipelines, truck-based transportation and storage of fuels, as gas or liquid, in underground or above-ground systems.

# 2 Executive Summary

The UK's 2024 Clean Power Action Plan [1] sets an ambitious target to reduce the carbon intensity of GB power generation by over 70% by 2030 from the 2023 baseline, aiming for an average emissions intensity "well-below 50gCO2e/kWh".

As the power sector is further decarbonised with increasing build-out of low marginal cost renewables such as solar and wind, this increases the need for greater dispatchable low carbon power generation capacity for periods of low sun and wind output.

The Clean Power Action Plan estimated 2 – 7 GW of low carbon dispatchable power installed capacity by 2030, coming from biomass, bioenergy with CCS (BECCS), gas CCS and hydrogen to power (H2P). Under the CCC's Balanced Pathway, defined to align with a Net Zero 2050 emissions reduction trajectory, estimates low carbon dispatchable power requirements at 3GW by 2030 rising to 15GW by 2040, and 38GW by 2050 [2].

To complement commercial and infrastructure limits on the build-out of other dispatchable technologies such as batteries (BESS), hydrogen to power(H2P), such as newbuild and retrofitted natural-gas generation assets, reciprocating engines, fuel cells and CHPs, offers critical system value by providing dispatchable, low-carbon flexibility. H2P could also provide a pathway to decarbonisation of existing unabated gas-fired assets which have significant economic lifetime remaining and could contribute towards energy security and resilience in the long term.

The delivery of H2P plants is complex; it requires integrating new technologies for production, transport, storage and power generation into a commercially viable value chain. Crucially, this value chain must be enabled in a way that integrates hydrogen to power into a renewables dominated system and will play a key role as a low carbon dispatchable generation technology. These assets are currently deployed in peaking or mid-merit roles, to meet short term peaks and inter-seasonal variable demand. At higher levels of intermittent renewables penetration, the contrast in role, dynamics and wholesale prices may become more stark with a potentially increased peaking role required for flexible power assets.

The Department for Energy Security and Net Zero (DESNZ) is currently developing a Hydrogen to Power Business Model (H2PBM) which aims to support the deployment of H2P at scale, and mitigate the risks associated with some of the barriers, including potential lack of investment due to First of a Kind (FOAK) challenges, such as supply chain development, as well as the cross-chain risk associated with a nascent hydrogen economy.

Robust, up-to-date cost data is key to supporting effective design of the H2PBM; reliable and future-proof cost inputs will help to identify which H2P technologies should be eligible for support, and under what conditions, to deliver policy which effectively balances the objectives of low-carbon technology deployment, energy security, and value for consumers.

This study examines the potential for hydrogen to power deployment in the UK across combined – and open cycle gas turbines (CCGT and OCGT), reciprocating engines, and fuel cell technologies. The study has looked to answer the following key questions:

1. What are the costs for hydrogen-capable combined and open-cycle turbines, and Reciprocating Engines? What are their costs relative to their unabated gas equivalents?

2. What are the costs for retrofitting or repowering an existing unabated gas plant to 100% Hydrogen capability?
3. What are the costs of blending hydrogen into an existing gas plant, at a range of blends?
4. How will the above costs evolve over time as the technology matures?
5. What are the barriers to deployment and how will this impact build/ramp-up rates?

Based on engagement with over 20 stakeholders, including hydrogen producers, Original Equipment Manufacturers (OEMs), and power generators, this report evaluates the technical readiness, infrastructure dependencies, cost profiles, and barriers to deployment of H2P technologies.

**Key findings include:**

<u>**Hydrogen value chain**</u>

- **Large-scale storage is required to address the misalignment between low carbon hydrogen production profiles and expected dispatch profiles** for hydrogen-fired generators if hydrogen is expected to displace natural gas in peaking and mid-merit roles. Storage capacity requirements are expected to be higher for electrolytic than CCS-enabled hydrogen supply given the flexible profile for the former compared to baseload production for the latter.
- **Salt cavern storage is the only proven, cost-effective solution available at the scale** required to facilitate H2P at scale. Distributed above-ground liquid or gaseous hydrogen storage is high cost, and is expected to pose significant planning and permitting challenges, particularly outside of existing industrial clusters.
- **Effective cross-sector coordination is critical to unlocking storage value and ensuring value for money.** Where possible, aligning power generation and industrial hydrogen demand will be critical to maximise storage utilisation and system flexibility, with transport networks connecting to multiple producers and offtakers via storage as the key enabler.

- **Storage needs increase sharply when 100% hydrogen generation is required.** Stakeholders engaged in salt cavern storage development provided estimates of the variation in hydrogen storage requirements for a CCGT with increasing proportions of 100% hydrogen operation. These estimates indicate that requiring 100% hydrogen for all dispatch would more than double storage capacity requirements compared to allowing natural gas blending in periods of prolonged low renewable output to achieve a c. 90% average H2 energy share (profile dependent), driven by seasonal demand variability and reserve margins.

<u>**Gas Turbines**</u>

***Technology:***

- **Turbine generators, comprising both combined-cycle (CCGT) and open-cycle (OCGT) configurations, account for approximately 35 GW of dispatchable GB capacity**. Much of this fleet is expected to remain in service into the 2030s. Decarbonisation of these assets through hydrogen blending or conversion is under active consideration by various plant operators interviewed as part of this study.
- **Major global turbine manufacturers are progressing the development of 100% hydrogen-capable turbines**; these are defined by the market as turbines capable of firing on either hydrogen or natural gas up to 100% with any blend in between, whilst maintaining the same key performance parameters currently observed for natural gas systems. This includes dynamic control features that enable adjustment of the hydrogen-to-natural gas fuel ratio during turbine

operation. Manufacturers are targeting fuel transitions between 100% hydrogen and 100% natural gas in either direction within several minutes, without impacting plant performance.

- **Most 100% hydrogen capable systems expected to be available in the early 2030s will still require natural gas for start-up** due to the increased technical complexity associated with maintaining combustion stability during the start-up phase. This implies that most turbines will need to retain a natural gas grid connection even when firing on 100% hydrogen outside of the start-up phase. One global OEM, Ansaldo, uses combustion technology which would allow for hydrogen start-up, but development times for other OEMs to deliver systems capable of start-up without natural gas are currently uncertain.
- **Commercial launch of hydrogen-capable turbines is targeted for the early 2030s across a range of capacities, but this could be delayed depending upon global market demand signals.** While technologies are progressing through lab development, OEMs require clear market signals (i.e. firm orders from developers) to justify the investment needed for full commercialisation. However, no major global market currently offers a credible combination of large-scale hydrogen supply, power deployment plans, or supporting policy frameworks. As a result, widespread rollout will depend on strong international policy support, particularly of the largest turbine classes where development costs and risks are greatest. In the absence of global demand signals to OEMs and developers, these timelines could slip.
- **Projects commissioned ahead of full technology launch of hydrogen turbines may need to be derated** (operated below maximum capacity by limiting fuel flow) by up to c.20% to ensure stable combustion and NOX emissions compliance. This derating effectively increases the capital cost per megawatt of delivered capacity.
- **OCGT and CCGT assets deployed since around 2010 can typically accommodate hydrogen blends of 20–50vol%,** depending on the turbine model and the compatibility of balance-of-plant components such as pipework and valves.
- **Gas-fired power stations commissioned from 2026 onwards are expected to be designed to be either hydrogen-ready or CCS-ready**, in line with Decarbonisation Readiness requirements applicable to all plants undergoing permitting from 2026, limiting future retrofit cost and complexity. In the case of hydrogen readiness, this means the plant is built with hydrogen-compatible Balance of Plant (BoP) components (such as pipework and valves) and a turbine design that can be upgraded in future to operate on up to 100% hydrogen. The combustion system itself would typically be retrofitted once hydrogen supply is available and suitable technologies have been commercialised for that specific model.

***Deployment and project pipeline:***

- **At least eight UK sites are evaluating hydrogen power generation projects using turbine technology** – both retrofit and newbuild – with target hydrogen blends of between 20 – 100vol%
- **Projects are mainly focused on CCGTs concentrated around planned salt cavern storage and large scale CCS-enabled hydrogen production across HyNet and Humberside.** This corresponds to a concentration of UK CCGT infrastructure around HyNet and Humberside.

***Cost and infrastructure requirements:***

- **Newbuild power stations designed to operate with 100% hydrogen-capable turbine generators are expected to be delivered at a CAPEX premium of <10%** versus an equivalent natural gas system once 100% turbine generators become available in the early 2030s.
- **Pipeline gas turbine generation projects could be delivered pre-2030 as "hydrogen-ready" at similar cost to an existing natural gas system,** and later retrofitted to be 100% hydrogen capable once systems become commercially available from OEMs in the 2030s. Based on limited

OEM feedback, retrofitting the hydrogen-ready turbine to enable full 100% hydrogen firing could be expected to cost in the region of 5% of total system CAPEX, around £50–55/kW (£45–50 million for a 900 MW plant).

- **Hydrogen turbine generators are expected to follow similar maintenance schedules** to their natural gas equivalents, with no material increase in operational expenditure (OPEX).

Reciprocating Engines

*Technology:*

- **Reciprocating engine generators represent a growing source of flexible generation capacity** in the UK. Deployment has accelerated over the past decade, particularly in response to the increasing need for fast-responding assets to support system balancing and reserve services.
- **Reciprocating engines designed for operation on 100% hydrogen are commercially available today. Unlike turbines, however, engines must be optimised for a narrower fuel blend;** an engine tuned for 100% hydrogen fuel is only able to accept c.20vol% natural gas without power derate, and operating such a system on 100% natural gas, though possible, will incur a power derate of 20 – 30%.
- **Blending and operational constraints could increase cross-chain risk in fuel supply,** as systems are not able to fire flexibly on natural gas in the event of a hydrogen supply disruption without compromised performance. This is particularly challenging for sites with Capacity Market contracts which are contractually obliged to maintain availability to dispatch at rated power[1].
- **Existing natural gas fired reciprocating engines can accept hydrogen up to a 20vol% blend with no or minimal modification required.** Retrofitting existing engines to high hydrogen blends is not expected to be viable due to significant power derating (c.30% derating at 100% hydrogen)
- **Key performance metrics including efficiency and ramp rates are consistent** between natural gas and hydrogen engine archetypes.

*Deployment and project pipeline:*

- **Stakeholders reported plans for at least two sub-50 MW hydrogen-fired reciprocating engine projects within the HyNet cluster.** A potential retrofit of an existing 50MW reciprocating engine generator on Teesside is also in the preliminary assessment stage.
- **Distributed concepts using onsite hydrogen production and above-ground storage (either gaseous or liquid) while potentially viable as small-scale demonstrators, are likely to be constrained at scale** by cost and planning constraints, and their commercial competitiveness relative to salt cavern–connected projects remains uncertain.

*Cost and infrastructure requirements*

- **Reciprocating engines capable of firing on 100% hydrogen are expected to carry a CAPEX premium of 10 – 20%** vs equivalent natural gas systems, with CAPEX approaching cost parity with natural gas systems by the late 2030s.
- **Retrofits to enable 20% hydrogen blends are typically low-cost or included within standard service upgrades,** incurring no additional capital expenditure. For 60% blends, costs rise to around £20/kW—approximately 3–4% of newbuild CAPEX at the 50 MW scale—while also

[1] *Based on current Capacity Market rules - HMG has issued a Call for Evidence on H2P participation in the Capacity Market*

requiring a power derate of about 20%. Full 100% hydrogen retrofits are estimated at £110–150/kW, or roughly 20–25% of newbuild costs, and would typically result in a 30% power derate.

**Combined Heat and Power (CHP)**

***Technology:***

- **Combined Heat and Power (CHP) systems generate electricity and recover waste heat, offering high overall efficiency.** In 2023, they accounted for 7.6% of UK electricity, mostly from natural gas and concentrated in industrial settings like refineries. Hydrogen conversion requirements are expected to align with those of the core generation technology (e.g., turbines or engines).
- **Projects are typically restricted to industrial locations with steam offtake capabilities, such as refineries.** While this is an effective approach for refinery decarbonisation, the potential for scaling such projects to provide significant dispatchable power to the grid appears limited.
- **Whole project efficiency and commercial viability is typically dependent on securing contracted steam offtake** – this will likely be limited to captive, local industrial customers.

***Deployment and project pipeline:***

- **Two hydrogen CHP projects were identified in stakeholder interviews**: EET Fuels' Stanlow refinery development in the Northwest, comprising a 50MW turbine integrated with Heat Recovery Steam Generators (HRSGs) configured to supply steam to the refinery which would be supplied with CCS-enabled hydrogen from HPP1, and Saltend Power Station, where a FEED study has been completed for conversion of two thirds of the plant's 1.2GW capacity to hydrogen. Here the site also currently supplies steam to the Saltend Chemicals park, as well as exporting power to the grid.

***Costs and infrastructure:***

- **Cost and performance considerations for hydrogen-fuelled CHP systems are assumed to align with those associated with converting the primary generator**, whether a gas turbine, reciprocating engine, or boiler, to hydrogen**.** Other CAPEX components associated with heat recovery and steam export are site specific, and are not expected to be comparable across projects.

**Fuel Cells**

***Technology:***

- Fuel cells are electrochemical systems that convert hydrogen into electricity, emitting only water and heat as by-products, with no NOX or CO2 emissions at the point of use. For stationary power generation, two fuel cell technologies are primarily relevant: Proton Exchange Membrane (PEM) fuel cells and Solid Oxide Fuel Cells (SOFCs). Both technologies are under ongoing development for industrial and utility-scale applications, but as research and engagement found no evidence of near-term deployment of SOFC systems for power generation in the UK, and limited evidence internationally, this report focuses exclusively on PEM fuel cells.

***Deployment and project pipeline:***

- In the UK, use of hydrogen fuel cells for power generation is currently limited to non-grid-connected applications, such as mobile, off-grid, or temporary backup systems. These are typically used on a project-specific basis and operate independently of the national electricity

network. At present, there are no operational grid-connected hydrogen fuel cell power generation assets in the UK.
- HDF, a European hydrogen fuel cell project developer, is exploring options for hydrogen to power projects in the UK, including a 40MW system in the HyNet region.

***Costs and infrastructure:***
- While offering up to c.10% higher LHV efficiency than single-cycle turbines or engines, fuel cell systems currently face CAPEX costs that are estimated to be two-to-three times higher than gas turbine systems. This is likely to constrain the opportunities for deployment to very-specific use cases. Systems may be viable in higher load factor applications, but going forward this will likely depend on CAPEX learning curves and hydrogen purification costs.
- Compared to turbine systems, PEM fuel cells are also more modular, which may offer deployment flexibility in distributed settings.

***<u>Summary</u>***

- 100% hydrogen-capable turbines are expected to be commercially available by the early 2030s, carrying a CAPEX premium of approximately 10% relative to natural gas systems, increasing to around 20% for early deployments requiring power derating. Available evidence from early-stage projects, and OEM engagement indicates that power derating of between 10 – 20% could be required for initial deployments. These turbines offer flexible operation on hydrogen-natural gas blends and the capacity to operate on natural gas in the event of hydrogen fuel supply disruption.
- Turbines typically require natural gas for start-up, necessitating dual fuel infrastructure.
- Reciprocating engines, commercially available today for 100% hydrogen, typically carry a CAPEX uplift of 10–20% compared to natural gas equivalents but face significant power reductions when operating on blends, limiting their operational capacity in the event of hydrogen fuel supply disruption.
- Industrial combined heat and power (CHP) systems are typically developed at refineries or sites with local steam demand, presenting viable local decarbonisation opportunities, dependent on steam offtake, but with limited potential for extensive rollout.
- Fuel cells, despite high efficiency, face high CAPEX versus competing technologies. Future deployment hinges on capital cost reductions and high load factor applications to leverage efficiency benefits.
- Effective deployment of all grid-scale hydrogen to power technologies depends heavily on hydrogen storage, particularly geographically limited salt caverns, with storage needs rising significantly at high hydrogen blends, and the potential for dual-fuel flexibility to optimise storage use and system reliability.
- Coordinated policy and regulatory frameworks across hydrogen production, storage, and power generation are essential to manage risks and enable investment.

# 3 Introduction

## Project Context

The UK's 2024 Clean Power Action Plan [1] sets an ambitious target to reduce the carbon intensity of GB power generation by over 70% by 2030 from the 2023 baseline, aiming for an average emissions intensity "well-below 50gCO2e/kWh". Achieving this goal will require a significant increase in renewable energy capacity and widespread development of long-duration energy storage and flexible, low-carbon power generation technologies.

Power generation from hydrogen, such as across newbuild and retrofitted natural-gas generation assets, reciprocating engines, fuel cells and CHPs offers critical system value by providing dispatchable, low-carbon flexibility. Together with long-duration energy storage, these technologies can support a renewables-dominated grid, and could play an enabling role in delivering the secure and decarbonised GB power system envisioned in the Clean Power Action Plan. Hydrogen to Power (H2P) provides a pathway to decarbonisation for unabated gas-fired assets with significant economic lifetime remaining.

The Department for Energy Security and Net Zero (DESNZ) is currently developing a Hydrogen to Power Business Model (H2PBM), a Dispatchable Power Agreement (DPA) type mechanism modelled on the intervention to support carbon capture and storage (CCS) power but adapted to the needs of H2P. These policy developments aim to support the deployment of H2P at scale, and mitigate identified barriers by de-risking investment in plants.

Barriers for H2P deployment might include the lack of investment due to First of a Kind (FOAK) challenges such as supply chain development, skills shortages and technology risk, as well as the cross-chain risk associated with a nascent hydrogen economy, which creates uncertainty around long-term fuel availability - an issue that individual plants are unlikely to mitigate effectively without coordinated, system-level solutions.

Robust, up-to-date cost data is key to supporting effective design of the H2PBM; reliable and future-proof cost inputs will help to identify which H2P technologies should be eligible for support, and under what conditions, to deliver policy which effectively balances the objectives of low-carbon technology deployment, energy security, and value for consumers.

This study draws and expands upon existing work in this area, combining recent research, reports, and targeted industry engagement to compile a comprehensive review of cost, performance and technology readiness for available H2P technologies, including both newbuild and retrofitted assets. Insights from this assessment aim to inform an accurate view of the current barriers affecting H2P technologies, and the scope for overcoming these challenges cost-effectively.

## Project Scope

This study seeks to review and assess cost and performance assumptions for hydrogen-fired power generation technologies which could feasibly be deployed at utility-scale in the UK across the 2030s and beyond. The study also seeks to identify industry challenges and barriers that may impact the deployment of H2P technologies and examines how related costs, risks, and barriers may evolve over time.

The overarching questions from DESNZ for this research were stated as follows:

1. What are the updated costs for hydrogen-capable combined and open-cycle turbines, and Reciprocating Engines? What are their costs relative to their unabated gas equivalents?
2. What are the costs for retrofitting or repowering an existing unabated gas plant to 100% Hydrogen capability?
3. What are the costs of blending hydrogen into an existing gas plant, at a range of blends?
4. How will the above costs evolve over time as the technology matures?
5. What are the barriers to deployment and how will this impact build/ramp-up rates?

Table 1 presents a summary of the scope of the review.

**Table 1: Hydrogen to power Research Scope**

| In Scope: | Out of Scope: |
|---|---|
| **Open cycle gas turbines** | Hydrogen production |
| **Reciprocating engines** | Hydrogen Transport & Storage |
| **Combined heat and power plants** | Regulatory compliance |
| **Hydrogen Fuel Cells** | Grid connections (H2, Gas, Power) |
| **Fuel handling systems** | |
| **Cooling systems** | |
| **Emissions and flue gas systems** | |
| **Hydrogen purification** | |
| **Hydrogen Compression** | |
| **Development Expenditure (DEVEX)** | |
| **Decommissioning Expenditure (DECEX)** | |
| **Fixed and variable OPEX, including operations and maintenance** | |

## Overview of the proposed UK hydrogen to power value chain

***Hydrogen production for power generation offtake***

Low-carbon power generation using hydrogen requires access to low-carbon hydrogen fuel and associated transport and storage infrastructure. In the UK, two principal production routes are being developed with government support: electrolytic hydrogen and carbon capture and storage (CCS)-enabled hydrogen. Both are eligible for revenue support via the Hydrogen Production Business Model (HPBM).

**Electrolytic hydrogen** is produced via electrolysis of water. Where renewable electricity is used as the input, the hydrogen is referred to as green hydrogen. UK Government support is provided through the HPBM, with funding allocated via competitive Hydrogen Allocation Rounds. Under the first round (HAR1), contracts were awarded to 125 MW of electrolysis capacity. In April 2025, a further 27 projects were shortlisted under the second round (HAR2).

**CCS-enabled hydrogen** is produced through the reformation of natural gas, with the resulting carbon dioxide captured and stored in geological formations. This form of hydrogen production depends on access to $CO_2$ transport and storage infrastructure, which is being developed and support allocated via the CCS Cluster Sequencing Process, whereby regional clusters are selected for the coordinated development of local $CO_2$ pipeline networks and offshore storage sites. Captured $CO_2$ may originate from hydrogen production via methane reformation or from industrial flue gases within the cluster.

Producing hydrogen from natural gas with carbon capture (known as CCS-enabled hydrogen) depends on access to $CO_2$ transport and storage infrastructure, which is not yet available at scale in the UK. To address this, the government established the CCS Cluster Sequencing Process, a phased programme to support the development of regional clusters where $CO_2$ emissions from hydrogen production and industrial processes can be captured and transported via shared pipeline networks to offshore geological storage.

The first phase of this process, referred to as Track-1, was launched in 2021. Two clusters were selected:

- HyNet Cluster, in the North West of England and North Wales
- East Coast Cluster, spanning the Teesside and Humber regions in the northeast

These clusters were prioritised for early deployment of $CO_2$ infrastructure and are intended to act as regional hubs for industrial decarbonisation. A Track-1 expansion process was initiated in December 2023 to bring additional projects into the HyNet cluster. A second phase, Track-2, is under consideration for future expansion of the national CCS and low-carbon hydrogen network.

Table 2 summarises a selection of major hydrogen production projects that have been publicly identified as targeting power generation as an offtake, with reference to the relevant allocation process where applicable. A full overview of H2P projects is provided in Section 4.1.

**Table 2 Major UK hydrogen production projects with public plans to supply hydrogen for power generation offtake**

| Project | Lead Developer | Location | Overview |
|---|---|---|---|
| **Aldbrough Hydrogen Pathfinder** | SSE | Humberside | 35MW electrolyser plus onsite salt cavern hydrogen storage to supply 50MW Aldbrough Hydrogen Pathfinder |
| **HPP 1** | EET Hydrogen | Northwest England (HyNet Cluster) | 350 MW CCS-enabled hydrogen production |
| **HPP 2** | EET Hydrogen | Northwest England | 1 GW CCS-enabled hydrogen production |

| | | | |
|---|---|---|---|
| | | (HyNet Cluster) | |
| **H2Teesside** | bp | Northeast England (East Coast Cluster) | 1.2GW CCS-enabled hydrogen production |
| **H2H Saltend** | Equinor | Humberside (East Coast Cluster) | 600 MW CCS-enabled hydrogen production |

All of the project developers for the projects listed above were engaged in this study, with the exception of bp, who were approached but declined to participate. Insights from other stakeholders and desk-based research provide a helpful understanding of H2P activities in the Teesside region, though some perspectives or details may not have been fully captured.

***Hydrogen transport and storage to support power generation offtake***

Generation technologies are typically categorised by their dispatch profiles:

- **Baseload:** Plants that operate continuously to meet the minimum level of electricity demand. In the UK, this role is primarily fulfilled by nuclear power stations, which provide stable, predictable output.
- **Mid-merit:** Assets that run during periods of moderate demand or reduced renewable output, particularly from wind. Gas-fired Combined Cycle Gas Turbines (CCGTs) are the UK's key mid-merit technology, offering greater operational flexibility than baseload generation, though with slower response times compared to peaking assets.
- **Peaking:** Highly flexible plants that operate for short durations during peak demand or sudden drops in renewable supply. Technologies include Open Cycle Gas Turbines (OCGTs), reciprocating engines, and battery energy storage systems (BESS). Peaking assets are essential for system stability, particularly during extreme demand or weather events that result in reduced energy production from renewables. However, OCGTs and reciprocating engines typically operate at lower thermal efficiencies than CCGTs, resulting in higher-cost electricity when dispatched.

Today, natural gas-fired turbines, including Combined Cycle (CCGTs) and Open Cycle (OCGTs), and reciprocating engines provide much of the UK's mid-merit and peaking generation. These technologies play a critical role in balancing the system and maintaining security of supply, particularly during winter periods when electricity demand is higher and renewable output is often lower or more volatile.

This study supports in the evaluation of the potential to replace natural gas in these roles with hydrogen-fired alternatives, including turbines, reciprocating engines, and fuel cells. Delivering this requires a hydrogen value chain—production, transport, and storage—capable of supporting the intermittent and seasonal dispatch profiles of mid-merit and peaking generation. However, current low-carbon hydrogen production models are not inherently aligned with these dispatch needs:

- CCS-enabled hydrogen is typically designed to operate at a steady baseload output to maximise plant efficiency and economic performance. When used for flexible power generation, this steady production profile can exceed demand unless there is sufficient storage or alternative, flexible offtakers.

- Electrolytic hydrogen is produced variably, depending on the availability of renewable electricity. Without adequate long-duration storage, this limits its ability to support generation during periods of high demand, particularly in winter, when renewable output may be low.

In both cases, large-scale hydrogen storage is necessary to decouple production from power demand, enabling hydrogen to be dispatched in alignment with electricity system requirements. Specifically:

- For CCS-enabled hydrogen, intermittent power generation requires either:
    - Access to significant flexible hydrogen storage to enable the production plant to run base load and manage surplus production during periods of low power demand, or
    - Integration with multiple, diverse and flexible offtakers, such as industrial or transport sectors, capable of absorbing hydrogen when power demand is insufficient.
- For electrolytic hydrogen, the electrolyser:
    - primarily wants to run when renewable generation is abundant and prices are low while dispatchable gas power plant demand is seasonal and highest in winter;
    - therefore, the feasibility of electrolytic H2P serving as a seasonal or long-duration storage to power would be constrained without even higher storage capacity to compensate for variability in renewable generation.

Notably, due to the inherently asynchronous nature of renewable generation relative to dispatchable power demand, the storage requirements for electrolytic hydrogen could be expected to be greater than for CCS-enabled hydrogen.

A summary of hydrogen storage technologies considered as potential solutions to support H2P development, including indicative CAPEX estimates for each, is provided in Table 3:

**Table 3 Overview of hydrogen storage technologies considered within scope**

| Storage Technology | Overview | Indicative CAPEX Estimate[2] (£,000/tonne) |
|---|---|---|
| **Low-pressure gaseous** | Storage at or below electrolyser outlet pressure (approx. 30 bar). Most suitable for small-scale, short-term buffer storage onsite at electrolytic hydrogen production facilities, avoiding the need for immediate compression. Limited energy density restricts use to short durations and smaller volumes. | c. 600 – 1,000 |
| **High-pressure gaseous** | Hydrogen compressed to 200–700 bar for transport cylinders or stationary storage tanks. Applicable at small to medium scales where higher volumetric energy density is needed. Challenges include high material costs and safety considerations related to high-pressure containment. | c. 1000 |

[2] *Cost estimates combine internal Baringa data with insights from three stakeholder interviews*

| | | |
|---|---|---|
| **Liquid** | Hydrogen liquefied at –253°C to achieve high volumetric energy density. Suitable for medium to large-scale storage where space is limited, but liquefaction is energy-intensive and costly. Boil-off losses and cryogenic infrastructure complexity present operational challenges. | 160 - 200 |
| **Geological (Salt Cavern)** | Large-scale, long-duration underground storage in salt formations at moderate pressures (50–200 bar). Requires suitable geology and significant upfront investment but offers low operational costs and high cycling capability. | 25 - 35 |
| **Geological (Depleted Well)** | Use of depleted oil/gas fields for storage; lower technology readiness; suited for interseasonal storage due to lower cycling rates, making it less suitable for rapid cycling applications such as power generation. | Lower TRL technology – CAPEX estimates unknown |

While a full assessment of the Hydrogen Transport and Storage (T&S) business models and their alignment with H2P technologies is beyond this study's scope, several stakeholder insights highlight key considerations for enabling H2P deployment in the UK:

- Salt cavern storage is the only mature, cost-effective option at the scale required for power generation in the tens of megawatts. One stakeholder estimated a practical upper limit of 50 tonnes for distributed sites outside industrial clusters using liquid or gaseous hydrogen storage constrained by planning and permitting.
- Hydrogen storage requirements could rise disproportionately when moving from predominantly hydrogen-based operation to 100% hydrogen-only operation. A salt cavern developer engaged as part of this study, for example, estimates that requiring a CCGT to run on 100% hydrogen whenever it is dispatched could more than double the storage capacity the plant must reserve to meet annual dispatch requirements compared to allowing for natural gas blending during periods of prolonged low renewable output and high demand (achieving c. 90% average hydrogen energy share, dependent upon the renewable/demand profile). While this reflects the view of a single stakeholder, Baringa internal analysis supports this view: removing the option to switch to or supplement with natural gas during system stress would significantly increase storage needs, driven by interseasonal variability and the requirement for full dispatchability during prolonged renewable shortfalls. The additional storage reserved by the plant may also reduce hydrogen availability for other users in a shared supply system. Given the limited evidence base, further analysis of storage requirements under varying operational regimes could be valuable in shaping robust business model design.

- Cross-sector coordination will be essential to maximise storage value and system-level decarbonisation, particularly across power generation, industrial and transport offtake sectors.

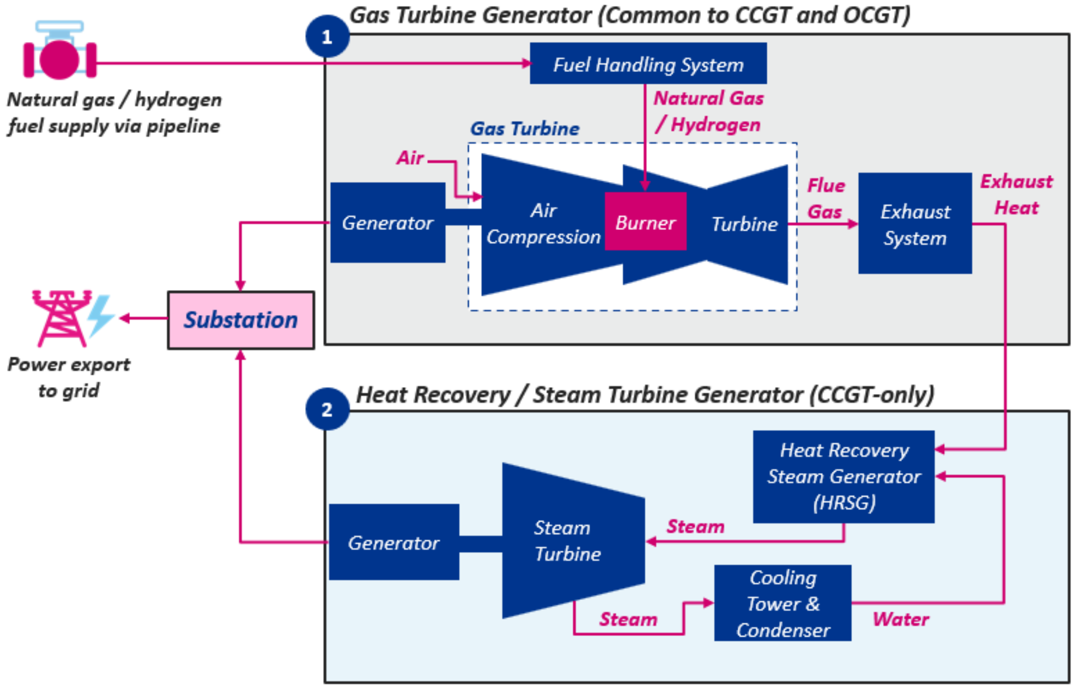
## Archetypes and definitions of system boundaries

The technologies, and their respective archetypes, investigated in this study are provided below.

***Open- and Combined Cycle Gas Turbines***

Open Cycle and Combined Cycle Gas Turbines (OCGTs and CCGTs) are two distinct configurations used in power generation. In an OCGT, atmospheric air is drawn in, compressed, mixed with fuel, and ignited. The resulting hot gases expand through the turbine, driving a generator. The working fluid - comprising the combustion gases - are then discharged to the atmosphere rather than recirculated, classifying the system as an ‘open cycle’ in thermodynamic terms. In contrast, CCGTs recover thermal energy from the gas turbine exhaust to generate steam via a Heat Recovery Steam Generator (HRSG). This steam then passes through a steam turbine, driving a secondary generator for additional electricity production. This configuration allows CCGTs to achieve higher efficiencies than OCGTs; however, OCGTs offer significantly faster start-up times, making them more suitable for applications requiring rapid response to fluctuating energy demands.

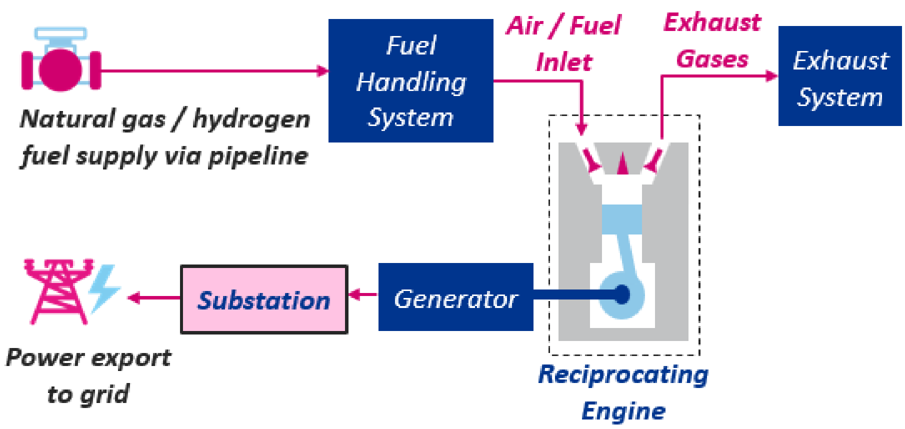
**Figure 1 System boundary: Open- and Combined Cycle Turbine Generators**




### *Reciprocating Engines*

Reciprocating engines are internal combustion engines used for power generation. An air-fuel mixture is ignited either by compression (diesel engines) or by a spark plug (natural gas / hydrogen engines), driving a piston that converts linear motion into rotary motion via a crankshaft to drive a

**Figure 2 System boundary reciprocating engine generator**




generator. These engines offer higher flexibility, rapid start-up capability, and good efficiency at partial loads, making them suitable for distributed generation and backup power applications. This study examines the conversion of existing natural gas assets to hydrogen and to assess the potential for new-build hydrogen-fired reciprocating engines.

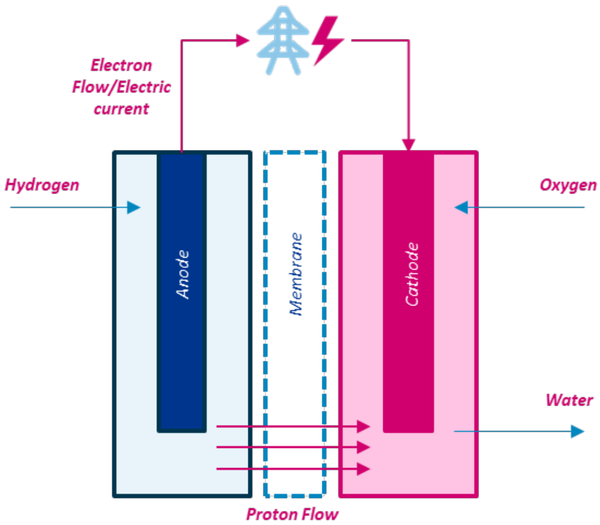
***Combined Heat and Power (CHP) Generation***

Combined Heat and Power (CHP) technologies refer to combustion generators (OCGTs, CCGTs, Reciprocating Engines) that are integrated with a heat recovery system that captures and recycles waste heat. This heat is then used in applications such as industrial processes and district heating networks, displacing heat demand that would otherwise be met by a conventional boiler. Depending on the grade (temperature) of heat; this could be supplied as hot water or steam for industrial process purposes.

***Fuel Cells***

Fuel cells are electrochemical devices that convert the chemical energy of a fuel directly into electricity through a controlled reaction, without combustion. In a typical fuel cell used for power generation, hydrogen is supplied to the anode side, where it splits into protons and electrons. The electrons are forced through an external circuit, generating direct current electricity, while the protons pass through an electrolyte membrane to the cathode. On the cathode side, the protons and electrons recombine with oxygen (often from the air) to form water, which is released as a by-product.

**Figure 3 Grid connected fuel cell system schematic**




***Hydrogen combustion characteristics***

Natural gas-fired power generation technologies, including OCGTs, CCGTs, and reciprocating engines, are mature and widely deployed both in the UK and globally. While the technical fundamentals of natural gas and hydrogen-fired systems are similar, the two fuels have distinct chemical and combustion properties, which influences the adaptation of existing power generation infrastructure. A comparison of fuel properties for natural gas and hydrogen fuel is presented in Table 4 below [3] [4] [5] .

**Table 4 Fuel properties of hydrogen vs methane (primary component of natural gas)**

| Fuel Property | Units | $CH_4$ | $H_2$ | Description |
|---|---|---|---|---|
| **Adiabatic Flame Temperature** | °C (in air) | 1,960 | 2,250 | Combustion flame temperature, assuming no heat is lost in the process |
| **Flame Speed** | cm/sec | 38 | 170 | Velocity at which unburned gases propagate into the flame |
| **Gravimetric Energy Density – *Lower Heating Value* (LHV)** | MJ/kg | 47 | 120 | Energy content per unit mass |
| **Volumetric Energy Density (LHV)** | $MJ/m^3$ | 31.7 | 10.2 | Energy content per unit volume |
| **Flammability Range** | % (by volume) | 5 - 15 | 4 - 75 | Range of fuel volumes that can form a combustible mixture with air (also known as the Explosive Limit) |
| **Molecular Weight** | g/mol | 16 | 2 | Mass of one mole of fuel (lower value implies lower density / higher diffusivity) |
| **Flame Luminosity** | - | Moderate | Low | The brightness of the flame when burned (relative measure) |

A summary of the performance and safety implications arising from these differing fuel properties when fuel switching between natural gas and hydrogen is presented in Table 5.

**Table 5 Performance and Safety Impacts of Fuel Switching from Natural Gas to Hydrogen**

| Hydrogen Property (vs $CH_4$) | Performance / Safety Implications for hydrogen vs natural gas systems | Possible modifications required for conversion to hydrogen |
|---|---|---|
| **Higher Adiabatic Flame Temperature** | • Increased thermal stress, impacting component lifespan<br>• Higher NOX emissions due to higher combustion temperature<br>• Reduced SCR efficiency, leading to increased ammonia "slip" (unreacted ammonia in the exhaust) and increased NOx emissions<br>• While higher flame temperatures can boost power, in practice output is typically capped to manage NOX emissions and material stress | • Heat-resistant materials and coatings in combustor / turbine blades<br>• Enhanced cooling systems to manage higher flame temperatures<br>• Adjustment of air-fuel ratio / implementation of Selective Catalytic Reduction systems (SCRs) for NOX control |
| **Higher Flame Speed** | • Increased risk of flashback, where the flame moves upstream toward fuel nozzles and the combustion chamber<br>• Combustion instability causing oscillations and pressure spikes<br>• Both phenomena can lead to equipment damage | • Replacement / modification of fuel injection nozzles<br>• Flame arrestors / stabilisers<br>• Ignition system adjustments |
| **Lower Volumetric Energy Density** | • Reduced power output per unit of fuel volume at a given combustion pressure | • Increased combustion pressure<br>• Increased volumetric flowrate |
| **Higher Flammability Range** | • Hydrogen will combust with both lower and higher concentrations of air present<br>• Increased risk of combustion instability i.e. uncontrolled combustion / flashback causing damage to turbine / engine, especially during low load operation<br>• Higher explosion risk in event of leakage | • More advanced monitoring systems to maintain controlled air-fuel mixtures<br>• Enhanced ventilation and leak detection systems to prevent fires and explosions in the event of a leak |
| **Lower Molecular Weight** | • Higher diffusivity<br>• Smaller molecule size means hydrogen can diffuse into some materials, causing embrittlement of certain metals, including steel | • Coating high-risk components with low-diffusivity materials e.g. nickel / nickel alloys |

| | | |
|---|---|---|
| **Lower Flame Luminosity** | • Combustion monitoring becomes more challenging | • Hydrogen-specific flame detectors |

This study aims to assess the design and performance considerations for newbuild assets with either 100% hydrogen or blended hydrogen natural gas firing capabilities, as well as technical modifications and associated costs required to retrofit existing assets for hydrogen and blended firing. This includes CCGTs, OCGTs, reciprocating engines and CHPs for blended and 100% hydrogen firing, and any impact on key performance metrics. It will also compare the cost and performance differences between newbuild systems capable of firing on hydrogen, as well as so-called "hydrogen-ready"[3] systems, and equivalent natural gas systems. The study will also review the current technoeconomic outlook for hydrogen fuel cells in power generation applications.

A summary of the approach is presented below:

1) **Data gathering and technology landscape review** – Available and emerging H2P technologies are assessed, including new installations and retrofits, 100% hydrogen-fuelled and hydrogen/natural gas blended systems. This includes review of key technical characteristics and evaluation of the Technology Readiness Level (TRL) of each solution to provide an initial assessment the potential rate and scale of deployment, assuming commercial barriers are addressed.
2) **Market engagement and stakeholder engagement** – Initial data gathering is tested with the market through semi-structured interviews and questionnaires. Key challenges and barriers impacting stakeholders are discussed.
3) **Potential policy interventions and actions** – Findings are quantified and reviewed in the context of H2P-related policy design, including the H2PBM.

**Table 6 Summary of Key Information Sources**

| Data Type | Interviews | Baringa Resource | Public Sources | DESNZ Sources |
|---|---|---|---|---|
| **Performance** | Equipment OEM / Operator & Developer Interviews | Internal expert interviews | Gas Turbine World Handbook 2024 [6] | Unabated Gas Generation Cost and Performance Assumptions |
| **Technical Requirements for H2 Fuelling** | Equipment OEM / Operator & Developer Interviews | Internal expert interviews | Academic Sources<br><br>OEM Whitepapers | Decarbonisation Readiness – Technical Studies *Hydrogen Readiness* (2022) |
| **Cost** | Equipment OEM / Operator & Developer Interviews | Internal expert interviews<br><br>Aggregated Baringa | Gas Turbine World Handbook 2024 | Unabated Gas Generation Cost and Performance Assumptions |

| | | | | |
|---|---|---|---|---|
| | | internal generation technology cost assumptions, informed by project insights and public data | Academic sources<br>Baringa internal benchmarks<br>UK and Non-UK Government publications | |
| **Technology Readiness** | Equipment OEM / Operator & Developer Interviews | Internal expert interviews | Open-access OEM product factsheets<br>Academic sources | - |
| **Barriers to deployment** | Equipment OEM / Operator & Developer Interviews | Internal expert interviews | Sector-specific media<br>Industry publications | - |

## Stakeholder Interview Procedure

For the purpose of this study, a series of stakeholder interviews were conducted across the H2P value chain. These interviews aimed to refine cost and performance assumptions gathered during the initial data collection phase and to gain a deeper understanding of the key challenges and barriers affecting the market.

**Participants:** The participants of this study were selected based on being part of the H2P value chain. A total of 21 semi-structured interviews have been conducted. Contacts were received from the following sources:

- The Department for Energy Security and Net Zero (DESNZ)
- Trade associations (e.g., Hydrogen UK)
- Internal Baringa network

**Table 7 Summary of stakeholders interviewed**

| Organisation Category: | Number of Interviews |
|---|---|
| **OEMs and Suppliers of turbines, reciprocating engines, and CHPs** | 5 |
| **OEMs and Suppliers of hydrogen fuel cells** | 1 |

| | |
|---|---|
| **Hydrogen to Power asset developers[4]** | 7 |
| **Hydrogen producers and developers** | 7 |
| **Trade Associations & SMEs(e.g Hydrogen UK)** | 1 |

EPC-related insights were also provided by asset developers with more mature project plans.

**Stakeholder Interview Procedure:** Organisations were contacted via an invitation email outlining the study's purpose, followed by an invitation letter requesting expressions of interest in participating. All interviews were conducted virtually, typically lasting between one and one-and-a-half hours.

Ahead of the interviews, participants received the interview questions along with a data form to provide insights on cost and performance metrics.

At the start of each interview, the participants were briefed on the study's objectives and key research outputs. They were also informed that they could review the interview notes to ensure their accuracy and could consent or decline the sharing of these notes with DESNZ.

Following the interviews, anonymised notes were sent to participants for review, with the option to request anonymity if desired.

## Limitations of methodology

***Bias from Interviewees:***

It is acknowledged that interviewee responses may be subject to specific biases, depending on their role within the hydrogen power value chain. Asset developers, in particular, may exhibit a strategic tendency to overstate costs or understate immaturity of their projects to strengthen the case for timely allocation of policy support, as well as optimism bias linked to the First-of-a-Kind (FOAK) nature of hydrogen-fired power projects.

To mitigate these risks, multiple organisations across each segment of the value chain were interviewed to enable cross-validation of inputs and identify inconsistencies. The selection also included stakeholders with substantial experience in hydrogen project development but without a direct commercial interest in power generation as a hydrogen end use, helping to provide a more neutral perspective.

Furthermore, Baringa and DESNZ established a baseline set of cost and performance assumptions at the outset to ensure that all stakeholder discussions were grounded in a common starting point.

***Data confidentiality:***

In general, participants were reluctant to disclose detailed CAPEX and OPEX data for both new-build and retrofit projects. While some indicative figures were provided, this limited data availability likely reflects the early stage of project development. Although some stakeholders reported receiving preliminary cost estimates from OEMs, either through retrofit feasibility assessments or early-stage discussions regarding new-build systems, most projects remain in the initial phases, and the

[4] *Includes existing thermal generation asset operators with hydrogen to power development plans.*

accuracy of such estimates is expected to be limited at this stage. OEMs offered high-level estimates of the expected CAPEX premium for hydrogen systems compared to natural gas alternatives where relevant. However, there was limited transparency regarding the baseline costs for natural gas systems, making direct comparisons challenging.

Despite these limitations, the breadth of stakeholder engagement allowed for the refinement of several initial cost estimates derived from the literature.

## 3.1 Project Outputs

This project summarises cost and data for available H2P technologies to inform UK policy development in this area including the design of the H2PBM. As a final output, the report seeks to highlight key barriers to deployment, from both a cost and technical perspective, the actions and interventions which are expected to be required to overcome these, and the impact on expected costs and timelines associated with H2P deployment in the UK.

# 4 Overview of findings by technology

## 4.1 Open- and Combined Cycle Turbines

### Introduction

As of 2025, CCGT and OCGT generation represent the largest source of dispatchable generation capacity in the UK, together accounting for over 35GW of nameplate generation capacity [7]. Following significant capacity build-out in the nineties and early noughties, the median asset age for this class of power generation stands at around 25 years for CCGTs and 36 years for OCGTs [8]. While many of these older plants are expected to remain operational into the 2030s, rising peak electricity demand and system flexibility needs are also expected to drive the development of new gas-fired turbine generation capacity in the near term. Identifying viable decarbonisation pathways, both for the existing fleet and for newbuild gas assets, will be critical to supporting system reliability while enabling the transition to a low-carbon power sector.

### Main Suppliers

Leading international suppliers of natural gas turbine generation equipment for OCGT and CCGT configurations include: Ansaldo Energia, General Electric (GE) Vernova, Mitsubishi Power, and Siemens Energy. All were interviewed as part of this study.

### UK Owners & Operators

Owners and operators of UK CCGT and OCGT assets include EDF Energy, ESB, EPUKi, InterGen, RWE, SSE Group, Uniper and Vitol VPI [8]. The majority were approached for interview; responses were received and interviews held with ESB, InterGen, RWE, and SSE Group, subject to availability within the study timeframe; Uniper did not respond to the interview request, and Vitol VPI's response was received after the allocated interview timeframe. EDF and EPUKi were not approached for interview due to the limited publicly available evidence of their involvement in H2P activities.

### UK Hydrogen to Power Development Pipeline

A total of eight CCGT and OCGT sites were identified through interviews as having been considered for retrofit to hydrogen or for development as new-build hydrogen-ready plants, including options for blended firing (Table 8). In the near term, access to large-scale local blue hydrogen production and salt cavern storage is a key driver of project siting, leading to a strong concentration of activity around the HyNet and Humberside industrial clusters. Stakeholders emphasised that any decision to progress with hydrogen firing at these sites is contingent upon policy development and market signals, including evidence of coordination and build-out across value chain.

**HyNet Cluster:**

- **ESB Carrington (884MW CCGT, retrofit):** ESB Carrington (884MW CCGT): ESB Carrington (commissioned 2016) uses Ansaldo Energia turbine technology. ESB has completed feasibility studies evaluating three possible hydrogen blend levels: 0–20%, 20–45%, and 45–100%. The studies assessed the modifications required to maintain the current performance of the natural gas-fired system (efficiency, power output, and ramp rates) when operating on hydrogen-natural gas blends. Results show that, with commercially available turbine technologies, blends of up to 70% are currently feasible. Ansaldo is developing turbine upgrades that will enable 100% hydrogen firing in this plant, and these upgrades are expected to be available in line with HyNet deployment timelines. Carrington is linked to the extensive hydrogen storage capacity of 1300GWh being developed in the North West by Storengy and the regional pipeline network by Cadent, both of which have undertaken FEED and are in advanced consenting.

- **Rocksavage (800MW CCGT, retrofit):** The Rocksavage CCGT in Runcorn, Northwest England has been in operation since 2000. Reference information shared by turbine OEMs indicates that with the combustion technology currently installed at the site, limited hydrogen blending in the range of c.10 – 15vol% could be technically achievable. However, analysis conducted to date suggests that blending at the 10vol% level could incur a reduction in power output of 25% (200MW), reflecting significant performance limitations. Detailed OEM assessment would be required for the site to determine a more precise estimate of blending capabilities and impact. Conversion to 100% hydrogen would require a substantial rebuild of much of the existing infrastructure. As a 25-year-old asset, the site illustrates the potential technical and economic challenges associated with hydrogen conversion for aging infrastructure.

- **Trafford Power Project (up to 1.2GW OCGT or reciprocating engine, newbuild):** Trafford's location positions the project as a potential offtaker for HyNet, and hydrogen readiness is being incorporated into the project design accordingly. A section 36 variation application has been submitted and the project is being developed in line with updated Decarbonisation Readiness requirements, which include ensuring that Balance of Plant components are compatible with 100% hydrogen. The project is being designed to operate on natural gas and blends up to 100% hydrogen from commissioning without power derating. Suitable fuel blending infrastructure has been designed into the site layout and planning permission has been secured for a pipeline which is permitted to transport either natural gas, hydrogen or a blend of both.

Humberside Cluster:

- **Keadby 2 (840MW CCGT, retrofit):** Commissioned in 2023, the facility is currently undergoing a technical assessment for hydrogen conversion. The site uses Siemens Energy gas and steam turbines which could be converted to 50 vol% hydrogen capability. This would require modifications to the asset, including installation of a blending skid, and replacement of pipework, balance of plant, and the combustion system.

- **Keadby Next Generation (c.910MW CCGT, newbuild):** Currently in the engineering design phase, the project is being designed to ultimately run on hydrogen, with some aspects configured for hydrogen where possible, but will be capable of running on natural gas or a blend of hydrogen and natural gas until a technically and commercially viable supply of hydrogen is available to the site. The project has applied for a Development Consent Order which was accepted for examination by the Planning Inspectorate in Sept 2025. Any scenario targeting 100% hydrogen firing will depend on when fully hydrogen-capable turbines become available from the OEM with appropriate commercial guarantees.

- **Aldbrough Hydrogen Pathfinder (50MW OCGT, newbuild):** The Aldbrough Hydrogen Pathfinder project is designed as a fully integrated power-to-gas-to-power system, utilising green hydrogen produced by a 35MW onsite electrolyser and stored in 40 GWh of onsite salt cavern storage. The project is developed independently from the region's larger-scale hydrogen and storage infrastructure but could be integrated. A single final investment decision is expected to encompass production, storage, and power generation, reflecting the interdependent viability of these components in this full chain configuration.

**Other Locations:**

- **RWE Pembroke (2.2GW CCGT, retrofit):** The Pembroke site operates 5 CCGT units. RWE has completed feasibility studies to assess hydrogen combustion for blends up to 40vol% and 100% hydrogen firing. Hydrogen supply is a key barrier for this site, which would require local CCS-enabled hydrogen production, together with non-pipeline carbon dioxide transport. Alternatively, the site could connect to Project Union, although it lies at the proposed network's periphery and would be among the last sites to receive hydrogen supply.

From the stakeholder interview feedback, a set of project archetypes has been identified based on proposed developments, representing the most likely candidates for medium-term H2P deployment in the UK. Each has been assessed in terms of cost, performance, and implementation barriers. A summary is provided in Table 9.

The majority of assets identified for potential medium-term conversion to hydrogen are large-scale CCGT projects. This may reflect that existing operators of higher-value, larger assets have a greater incentive to continue asset operation and are more likely to have considered the long-term viability of their existing assets.  By contrast, new-build, smaller-scale OCGT's or other H2P technologies are both more flexible by location and require comparatively less development expenditure. As such, developers may be waiting to explore hydrogen conversion options for these smaller assets until greater clarity is available around the policy landscape and business model design.

**Table 8 Summary of UK sites using turbine technologies discussed in interviews which are being considered for potential future hydrogen firing[5]**

| Location / Cluster | Site | Operational / Pipeline | Tech | Plant Capacity (MW) | Year of first Operation | Operator | Status & Overview |
|---|---|---|---|---|---|---|---|
| HyNet | Carrington | Operational | CCGT | 884 | 2016 | ESB | Pre-FEED ongoing. Feasibility studies complete for conversion to three blend levels (0-20%; 20-45%;45-100%) |
| HyNet | Rocksavage | Operational | CCGT | 800 | 2000 | InterGen | Reference information concerning blending impact shared by OEM indicates low volume blending would incur a significant power derate for existing plant technology |
| HyNet | Trafford | Pipeline | OCGT /recip | Up to 1,200 | *2026* | Carlton Power | Project is being designed to operate on natural gas and blends up to 100% hydrogen from commissioning without power derating. |
| Humber | Keadby 2 | Operational | CCGT | 840 | 2023 | SSE Thermal | Facility is currently undergoing a technical assessment for hydrogen conversion. |
| Humber | Keadby Next Gen | Pipeline | CCGT | c.910 | *Unconfirmed* | SSE Thermal | Currently in the engineering design phase, the project is being designed to ultimately run on natural gas, hydrogen or a blend of both fuels. |
| Humber | Aldbrough Pathfinder | Pipeline | OCGT | 50 | *Unconfirmed* | SSE Thermal | Green hydrogen production supplying the site has been shortlisted for HAR2 Hydrogen Production Business Model support, with commissioning targeted before 2030, subject to appropriate policy support. |
| South-west Wales | Pembroke | Operational | CCGT | 2,200 | 2012 | RWE | Feasibility studies completed to assess hydrogen combustion for blends up to 40vol% and 100% hydrogen firing. Hydrogen supply is a key barrier for this site. |

[5] *A further OCGT site is being evaluated for potential hydrogen firing; project-specific details have been withheld for confidentiality.*

**Table 9 Hydrogen to power turbine archetypes assessed**

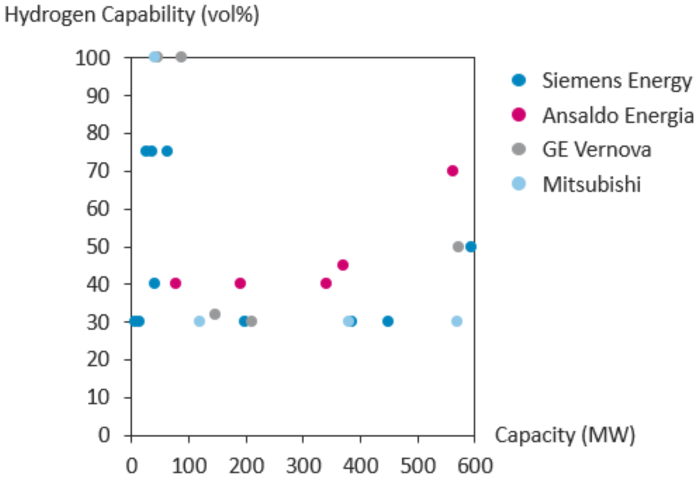
| Label | Technology | Newbuild / Retrofit | Description | Capacity (MW) | Max. Hydrogen Blend Ratio(s) (vol%) | Storage Solution |
|---|---|---|---|---|---|---|
| **Retrofit CCGT** | CCGT | Retrofit | Retrofit of existing system to blended or 100% hydrogen from 2030 to align with large-scale H2 production | 900 | Up to: 20, 45, 70, 100 vol%[6] | Salt Cavern |
| **Newbuild H2-ready CCGT** | CCGT | Newbuild | Commissioned pre-2030 with 100% H2-ready BoP<br><br>Retrofit post-2030 to 100% hydrogen-capable to align with availability of turbine upgrades | 900 | Pre-2030: 50 – 70vol% (defined by selected turbine)<br><br>Post-retrofit: 100vol% | Salt Cavern |
| **Newbuild 100% H2-capable CCGT** | CCGT | Newbuild | Commissioned post-2030. 100% hydrogen-capable from start of operation. | 900 | 100% | Salt Cavern |
| **Newbuild 100% H2-capable OCGT** | OCGT | Newbuild | Commissioned pre-2030. 100% hydrogen-capable from start of operation | 50 | 100% | Salt Cavern |

[6] *Hydrogen blend levels in the CCGT retrofit case reflect stakeholder-identified thresholds from prior studies, beyond which a step change in conversion costs occurs. This threshold varies by plant and turbine model.*

## Technology Readiness and Future Outlook

***Hydrogen capabilities of current turbine systems***

**Figure 4 Hydrogen blend limits for commercially available turbines by capacity**




Turbines are estimated to account for c. 25 – 35% of total installed cost for current natural gas OCGT and CCGT units, and turbine technology is a key determinant of hydrogen capability for both newbuild and existing assets. Figure 4 summarises the hydrogen combustion capabilities across commercially available systems for the four leading international turbine OEM portfolios: Siemens Energy, GE Vernova, Mitsubishi, and Ansaldo Energia. As shown, most turbine units deployed in newbuild systems today are typically 30 – 50vol% hydrogen-capable by default. A full breakdown of these systems and their single-cycle efficiencies is presented in Appendix D.

***Development challenges for hydrogen-capable turbines***

Hydrogen-capable turbines are an incremental evolution of conventional natural gas platforms, adapted to accommodate hydrogen's distinct combustion characteristics—such as faster flame speeds, higher flame temperatures, and increased $NO_x$ formation potential.[7] While the overall turbine architecture remains largely unchanged, targeted modifications to combustor design, cooling systems, and control algorithms are required.

Turbines capable of operating on 100% hydrogen are already in service, primarily in sub-100 MW industrial applications. While these systems are available and ready to deploy today, industrial turbines models are optimised for durability over performance and therefore typically operate at lower efficiencies, around 35% (LHV), as compared to up to 42% for state-of-the-art larger turbine models typically used in power generation, equating to a 20% higher fuel consumption per unit power output for these industrial turbine models.

OEMs are actively working to deliver hydrogen-capable systems across the full turbine capacity range, including larger archetypes, that can match the performance characteristics of existing state-

[7] *Further details on NOX management provided in Appendix C*

of-the-art natural gas turbines, including efficiency, ramp rates, minimum load, and hot/cold start-up times.

***Research and development for hydrogen turbines***

All OEMs report that there is a viable technical pathway to developing 100% hydrogen-capable archetypes with performance metrics equivalent to that of existing natural gas fired systems in the early 2030s across the full range of existing turbine capacities currently available commercially, pending successful testing and product validation.

Critically, however, commercial launch of these systems is dependent on visibility of market demand, so could be delayed relative to the technology development timelines.

The path from "technical readiness" (successful pilot operation) to commercial launch (fully certified product with OEM warranties and guarantees) usually requires:

1. **Extended operational data** e.g., long-term laboratory and field testing.
2. **Component fatigue/aging studies** to validate durability.
3. **Regulatory/grid compliance testing** for emissions, safety, and reliability.
4. **Market authorisation and risk guarantees**, including performance assurances.

While the duration of the commercial launch process will vary by OEM and turbine model, an estimated development period of c.3 – 7 years from pilot demonstration to commercial launch might be expected. To support this progression, OEMs are investing in dedicated testing infrastructure. For example, Mitsubishi Heavy Industries has established the Hydrogen Park Takasago, an integrated facility for hydrogen production and turbine testing. Similarly, Siemens Energy is actively advancing hydrogen turbine technology at its combustion test centre in Germany, including through the "Mission H2 Power" R&D partnership with SSE.

Availability and cost of hydrogen fuel remains a key challenge impeding turbine testing, particularly for the largest turbine archetypes typically used in CCGT systems. These machines require substantial volumes of hydrogen for full-system tests, which can make sustained testing economically and logistically difficult. As a result, development timelines could be delayed. To address this, some OEMs have adopted interim strategies such as testing individual burner components or sub-sections of the combustion system under representative conditions, rather than running full-scale engine tests. While these approaches can provide valuable data on flame stability and emissions, they are not ideal substitutes for full-engine validation, particularly for assessment of integrated system performance, thermal stresses, and long-duration reliability under real-world conditions.

***Hydrogen Start-Up Constraints and OEM Design Pathways***

OEMs report that the first generation of 100% hydrogen-capable turbines will still require start-up on natural gas, meaning sites must maintain a gas connection to ensure reliable ignition and stable start-up and are therefore not able to avoid gas grid connection costs. Hydrogen's high flame speed and low ignition energy make controlled ignition challenging during both cold and hot starts. During cold starts, the risk of flame flashback and unstable combustion is higher due to low component temperatures. During hot starts, while temperatures are elevated, hydrogen's rapid combustion can cause localised overheating and flame instability, complicating combustion control compared to natural gas.

Ansaldo Energia is an exception; Ansaldo turbines use sequential combustion technology[8] that allows for hydrogen start-up without additional R&D beyond the current development phase. However, other OEMs are unlikely to switch to this technology, as combustion system choices are typically fixed for each turbine platform. Consequently, retaining natural gas start-up capability remains the practical approach for early hydrogen turbine deployments. OEMs (besides Ansaldo) were not able to confirm when turbines capable of hydrogen-only start-up would be commercially available.

As a result, most sites deploying early hydrogen-capable turbines will need to maintain a connection to the natural gas grid to support start-up operations. The additional CAPEX associated with securing and maintaining dual gas grid connections (one for hydrogen and one for natural gas) has not been analysed in the context of this study and is not included in the CAPEX figures presented below, but should be noted as an additional cost consideration when planning early hydrogen turbine projects.

***OEM insights:***

- **Ansaldo Energia:** The only OEM using sequential combustion, a turbine combustion technology that uses separate combustion chambers in series. Supports 40–70 vol% hydrogen across current models (78–563 MW). Retrofit feasibility assessments have been completed for existing customers, including in the UK. Lab tests confirm 100% firing is feasible for existing systems with derating.
- **GE Vernova:** Sub-100 MW 100% hydrogen-capable turbines are already in operation across industrial applications. Larger turbines in the 9HA series (450 – 570MW) are certified for 50 vol% blends. GE Vernova is targeting commercial launch of 100% hydrogen-capable DLE systems in B- and E-class turbines (45–147 MW) by 2026.
- **Mitsubishi Power:** 100% hydrogen systems available at 40 MW scale. Larger turbines (e.g. 573 MW M701J) currently support 30 vol% blends. 100% hydrogen capable targeted for 2030. Also pursuing ammonia-fuelled turbines.
- **Siemens Energy:** Supports 30–75 vol% blends across its DLE portfolio, which spans 25 – 590MW. Priorities for hydrogen technology development span 50–600 MW turbines, with the SGT-400 (10–15 MW) likely to be its first commercially available 100% hydrogen-certified model (2026–2027). Larger turbines (e.g those models spanning the c.45 – 600MW range) remain under development, with Siemens aiming to achieve 100% hydrogen capable turbines across the current portfolio capacity range by the early 2030s.

***Implications for UK hydrogen turbine deployment***

For projects aiming to deploy turbines capable of operating on 100% hydrogen prior to the commercial launch of the target turbine model, OEMs and project developers have indicated that commercial guarantees would only be possible if power derating is applied. Power derating refers to the intentional reduction of a turbine's maximum power output below its nominal rating to ensure reliable operation and protect the equipment when operating under challenging or less-proven conditions, such as using 100% hydrogen fuel. This is typically achieved by limiting the fuel flow into the combustion chamber, which reduces the combustion temperature and overall power output, helping to manage thermal stresses and maintain combustion stability.

[8] *Sequential combustion involves two combustion chambers arranged in series, allowing staged fuel injection and temperature control to reduce peak flame temperatures and $NO_x$ formation. While effective for hydrogen combustion, its increased complexity and integration challenges limit widespread adoption across turbine platforms.*

OEMs confirmed they are undertaking technical studies for the projects listed in Table 8 and have conducted similar assessments in markets such as Germany, where recent gas turbine generation auctions require bidders to demonstrate that new-build plants are designed with a viable technical pathway for future hydrogen conversion. However, according to the OEMs interviewed, no global market, including the UK, has yet established a sufficiently comprehensive support framework or long-term strategy across the full H2P value chain to drive uptake beyond innovation and demonstration projects. As a result, wider commercial deployment remains dependent on the introduction of coordinated policy measures and sustained market signals, both of which are currently lacking at a global level.

## Requirements and Modifications for Hydrogen Fuelling

A detailed summary of the system components which should be considered when assessing newbuild and existing sites for hydrogen integration is provided in Appendix B. Detailed discussion of NOX management for turbine systems is provided in Appendix C.

***Retrofit of existing sites***

Any retrofit allow for hydrogen firing requires a detailed, site-specific technical assessment. Feasibility, cost, and complexity depend largely on the hydrogen compatibility of the existing Balance of Plant, such as pipework, venting, hazardous area zoning, and materials. NOX control is a critical limiting factor for many existing systems.

Real-world insights illustrate this variability. Initial technical studies indicate that Carrington CCGT (commissioned 2016) turbines could be modified to handle up to 70% hydrogen blends without derate using current technology. Beyond 70%, water injection is needed for NOX control, increasing CAPEX due to water treatment requirements and causing a 3–5% efficiency loss. This is a case-specific insight for this project, and ESB had indicated that their supplier, Ansaldo Energia, is currently developing turbine technology upgrades which are expected to be available in the early 2030s which would allow for turbine retrofit to maintain systems at their current performance and NOX emissions levels without requiring water injection for NOX control.

By contrast, Rocksavage CCGT (commissioned 2000) faces a 25% derate at just 30vol% hydrogen blend, reflecting limitations to retrofit potential for older plants and turbine designs, and highlighting that for aging assets, hydrogen retrofit may not yield significant cost savings versus newbuild, with conversion approaching the scope and cost of a full repowering, comparable to a newbuild project.

***Retrofit of Hydrogen-ready sites***

By contrast, systems currently being designed as “hydrogen-ready” are expected, based on OEM and stakeholder feedback, to include fully hydrogen-compatible Balance of Plant from the outset. This typically involves the integration of appropriate safety zoning, hydrogen-suitable materials, and layouts that accommodate hydrogen handling and control requirements. The associated gas turbines are also being developed with combustion systems that can be modified or retrofitted to support 100% hydrogen firing once commercial technologies are available. Retrofit of such hydrogen-ready systems is expected to be relatively straightforward, with OEMs indicating future upgrade costs in the range of 5–10% of the original plant CAPEX.

Additional information on retrofit requirements and CAPEX is provided under the Cost and Performance Data section below.

## Cost and Performance Data

Due to the shared fundamental design principles between hydrogen and natural gas turbines, CAPEX estimates for hydrogen turbine systems can be benchmarked against equivalent natural gas turbine archetypes. Stakeholders were asked to share any CAPEX and OPEX data for new-build and retrofit hydrogen and natural-gas turbine generators. The information provided offered limited insight, with hydrogen CAPEX generally reported only as a percentage uplift relative to natural-gas systems. Estimating absolute CAPEX is further complicated by current market conditions, as global demand for dispatchable generation driven by rapid datacentre expansion is creating supply-chain bottlenecks for major equipment, including gas turbines.  As a result, significant uncertainty remains around CAPEX estimates in the current market. The CAPEX data presented here (and in Appendix A) is based on Baringa's internal estimates for CCGT and OCGT systems, drawing on public data from global government sources, international energy bodies, real-world project insights, and limited stakeholder contributions; specifically, two stakeholders provided CAPEX estimates for CCGT systems, and one provided estimates for a hydrogen-compatible turbine unit.

Regarding OPEX for hydrogen turbine generators, OEMs confirmed that hydrogen systems are expected to follow similar maintenance schedules to their natural gas equivalents, with no material increase in non-fuel operational expenditure (OPEX).

Increases in core turbine CAPEX are anticipated in the 2030s for 100% hydrogen-capable systems, driven by research and development requirements and elevated costs associated with first-of-a-kind (FOAK) units. Main mechanical BoP includes fuel handling, turbine auxiliaries, and exhaust systems for OCGT/CCGT, with cooling towers, condensers, and HRSG added for CCGT. Additional minor increases in BoP CAPEX are expected to facilitate hydrogen blending.

Table 10 outlines the core CAPEX assumptions by line item for newbuild hydrogen project archetypes, expressed as percentage uplifts relative to the natural gas equivalent. A 900 MW CCGT and 50 MW OCGT were selected based on typical project archetypes from developer and OEM consultations. As communicated by OEMs, smaller (up to c.50 MW) OCGTs are likely to be the first available units, but since the underlying technology is the same, larger units (100–200 MW+) are also expected to emerge in the early 2030s, potentially enabling CAPEX reductions through scale.

**For the 900 MW CCGT system:**

- *Pre-2030 Hydrogen-Ready:*
    - A plant designed with hydrogen-compatible Balance of Plant (BoP) and a turbine that can be retrofitted to run on hydrogen once systems become commercially available from OEMs (expected in the 2030s). To meet the UK's Decarbonisation Readiness rules [9], relevant for newbuilds from 2026, the plant includes hydrogen-compatible BoP features from the outset, such as appropriate pipework and ATEX-rated safety zoning[9], at no significant additional cost.
    - A 10% CAPEX uplift is applied to the turbine for future hydrogen capability. Retrofitting the hydrogen-ready turbine to enable full 100% hydrogen firing is assumed to cost c.5% of total system CAPEX, around £50–55/kW (£45–50 million for a 900 MW plant).

[9] *ATEX (Atmosphères Explosibles): Standards for equipment used in explosive atmospheres, ensuring safe operation in environments with flammable gases like hydrogen.*

- *Post-2030 Newbuild 100% Hydrogen-Capable:*
    - A plant built with a turbine that can fire on 100% hydrogen, natural gas, or any blend. Start-up must still use natural gas unless the selected turbine uses sequential combustion technology. No derating is needed. CAPEX includes the 10% turbine premium but avoids retrofit costs.

**For the 50 MW system:**

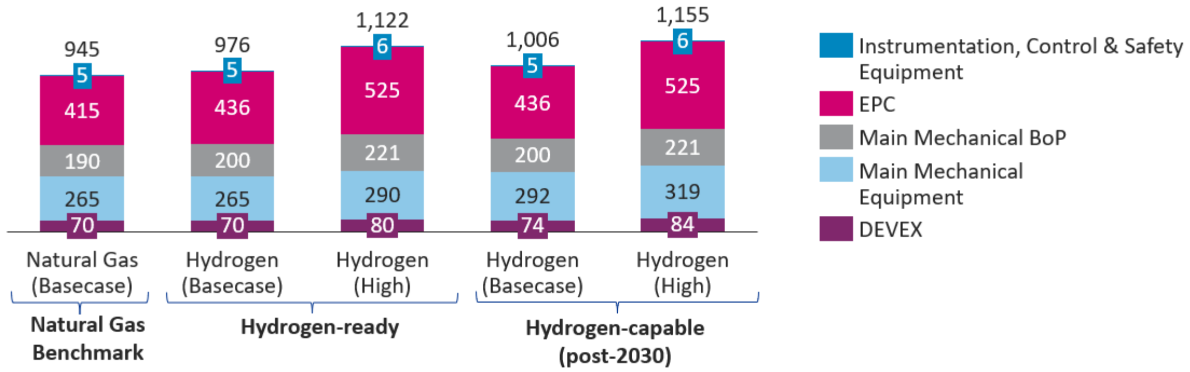
- *Pre-2030 100% Hydrogen-Capable:*
    - A first-of-a-kind system, commissioned ahead of commercial hydrogen turbine availability. It includes a turbine with 100% hydrogen capability but is assumed to be derated by 10% (lower bound estimate) to 20% (upper bound estimate) to enable early deployment.
    - Total turbine CAPEX is c.37.5% higher: 10% for hydrogen-capable hardware, and an effective 25% uplift due to the derating. Higher DEVEX is also assumed due to supply chain immaturity.
    - Derate assumptions are informed by figures discussed with both OEMs and developers. Turbines with lower derates would be expected to incur proportionally smaller CAPEX increases. Further OEM and project data will be required to improve accuracy as more projects develop.
    - In this case, it is important to note that the derate assumptions apply at facility start-up. However, in theory, this derating may not persist over the full lifetime of the facility, as the installed machine could potentially be upgraded once a fully rated, 100% hydrogen-capable model for this turbine archetype becomes commercially available post-2030. In Table 10 below, the increased CAPEX assumed for the main mechanical equipment is driven by this initial derating assumption. Should the derate be removed through a future upgrade, this would effectively reduce the lifetime CAPEX burden associated with the plant, as the cost uplift linked to the initial derate would no longer apply over the full operational life.
- *Post-2030 Newbuild 100% Hydrogen-Capable:*
  A system that can run on any blend of natural gas or hydrogen up to 100% without derating. A 10% CAPEX premium still applies to the turbine, but no additional retrofit or performance penalties are assumed

**Table 10 Estimated CAPEX uplift for hydrogen archetypes vs equivalent natural gas systems**

| CAPEX Component | % increase vs newbuild natural gas baseline | | | |
|---|---|---|---|---|
| | 900 MW CCGT | | 50 MWe OCGT | |
| | Pre-2030 Newbuild H2-Ready | Post-2030 Newbuild 100% H2-Capable | Pre-2030 Newbuild 100% H2-Capable | Post-2030 Newbuild 100% H2-Capable |
| **DEVEX** | 0% | 5% | 20% | 15% |
| **Main Mechanical Equipment** | 0% | 10% | 35-40% | 10% |
| **Main Mechanical BoP** | 5% | 5% | 5% | 5% |
| **Instrumentation, Control & Safety Equipment** | 5% | 5% | 10% | 10% |
| **Civils & Installation** | 5% | 5% | 10% | 10% |

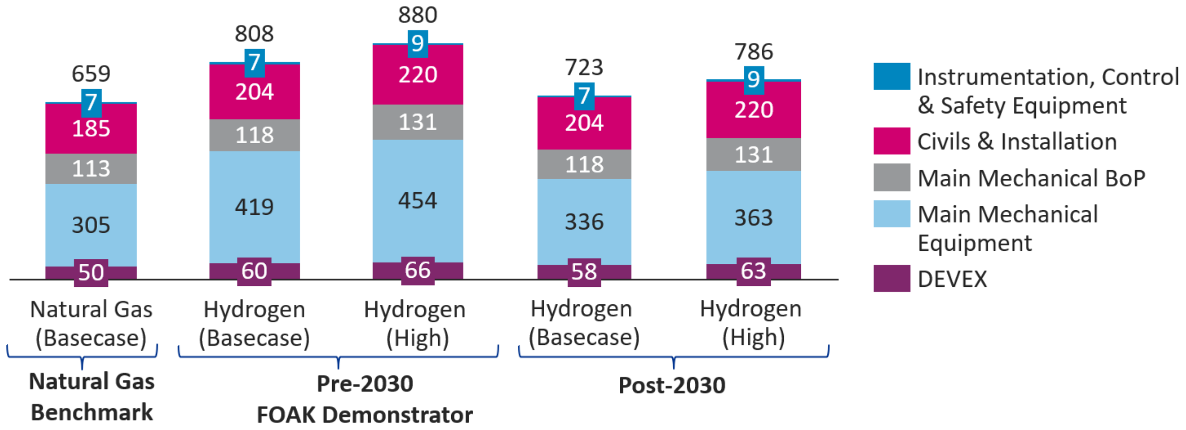
Resulting unit CAPEX estimates for these 900MW systems are presented in Figure 5. Here, the "Basecase" and "High" cases are derived from the range of natural gas CAPEX estimates compiled in Baringa's database, with the percentage uplift for the hydrogen case applied to each CAPEX line item as defined above.

**Figure 5 Unit CAPEX estimates for 900MW hydrogen ready and hydrogen capable CCGT archetypes (£/kW, 2025)**




Resulting unit CAPEX estimates for the 50MW systems, applying a 20% power derate assumption, are presented in Figure 6.

**Figure 6 Unit CAPEX estimates for 50MW hydrogen-capable OCGT archetypes (£/kW, 2025)**




**Retrofit:** Retrofit CAPEX is highly sensitive to both the age and existing hydrogen capability of the turbine and other BoP systems, as well as the targeted hydrogen blend ratio. Limited developer data is available to inform precise retrofit CAPEX estimates.

Based on stakeholder feedback, for plants nearing the end of their operational lifespan (assumed 25 years for CCGTs and OCGTs), retrofitting existing turbine equipment to hydrogen is not expected to be a more resource-efficient approach than full repowering; that is, replacing turbines with hydrogen-capable equivalents, and substantially or completely updating BoP components for hydrogen compatibility. Such aging systems typically lack hydrogen-compatible mechanical balance-of-plant components, including pipework and associated infrastructure. Therefore, the primary cost advantage of developing a hydrogen-fired facility on these sites is likely limited to the usual benefits of repowering, mainly the reuse of existing grid connections and site infrastructure, and extension of existing permits, though these savings can be limited by refurbishment needs. Overall, CAPEX savings from repowering could be expected to range from low single digits up to around 15%. OEMs have echoed this in discussions, indicating that cost savings versus new builds are typically limited.

Key performance metrics for typical gas-fired CCGT /OCGT are presented in Table 11 [10]. Based on OEM feedback, performance of existing systems will be maintained when firing on hydrogen-capable turbines operating at any blend up to the defined maximum hydrogen blend for the system.

**Table 11 Key Performance Metrics for Typical Gas-Fired CCGT/OCGT Systems**

| Parameter | Unit | OCGT | | CCGT | |
|---|---|---|---|---|---|
| | | Central | State-of-the-Art | Central | State-of-the-Art |
| **Net Efficiency (LHV)** | % | 38% | 43% | 58% | 64% |
| **Hot start-up time** | min | 5 – 30 | 5 - 10 | 60 – 90 | 30 - 40 |
| **Cold start-up time** | [min] or [h] | 5 – 11 min | 5 – 10 min | 3 – 4 h | 30 – 40 min |
| **Average ramp rate** | % Rated Power / min | 8 – 12 % | 10 – 15 % | 2 – 4% | 4 – 8 % |

## Barriers to Deployment and Scale-up

- **Infrastructure dependency:** Deployment depends on proximity to hydrogen transport and large-scale geological storage, which are not yet in place. Locations where the appropriate geology exists for development of hydrogen (salt cavern) storage are limited within the UK, which can limit the deployment of large scale, transmission and storage connected H2P projects to those locations. In other locations, co-located hydrogen production, storage and power generation seem more viable.
- **Policy and regulatory uncertainty and timelines:** Design of the H2PBM business model should consider developments in the production, transport and storage business models to ensure there is a coherent investment framework for H2P offtakers. Potential barriers to deployment, as indicated by stakeholders, include**:**
    - Across all regions, there is a risk that H2P projects won't reach FID without clear, coordinated business models for production, transport and storage and power generation.
    - In particular for debt or infrastructure financing, projects will need long-term contracts and cross-chain risks will need to be mitigated for developers to have the confidence to commit.
    - Developers need to have fuel supply confidence to progress to project development. The majority of project development stakeholders interviewed have indicated that their projects will rely on CCS-enabled hydrogen supply from HPP1/2 and H2H Saltend, with the notable exception of the Aldbrough Hydrogen Pathfinder. However, support for green hydrogen production and appropriate storage may unlock increased interest in smaller-scale project projects beyond those identified in stakeholder interviews, with some stakeholders flagging this as a potential area for exploration.
    - A hydrogen network code will be needed to facilitate piped hydrogen transport, including rules on access, tariffs, and quality standards.
    - The T&S business models should consider the operational dynamics between hydrogen storage assets and power offtakes to enable the peaking and mid-merit generation profiles expected from hydrogen power generation assets.

- **Workforce shortages:** Multiple developers cited the shortage of skilled construction labour as a constraint, noting that even at current rates of energy infrastructure deployment, projects are facing timeline extensions due to skilled labour shortages. While larger developers may be able to transfer some of this risk to Engineering, Procurement and Construction (EPC) providers, stakeholders noted that these firms are increasingly introducing more stringent contingency provisions into agreements to safeguard against labour-related disruptions.
- **Supply chain:** Supply chains mirror those of natural gas turbine generation assets. Currently, accelerated deployment of gas turbine generators to address increasing power demand from data centre demand is placing upward pressure on gas turbine pricing and supply, with OEMs reported that project developers have been paying to reserve manufacturing slots in advance, implying potential delays to turbine procurement in the near term. Turbine OEMs acknowledged this cost escalation but were unwilling to disclose detailed figures on the scale of CAPEX increases. One OEM reported that they expect production capacity to scale within two to three years to address the current supply bottleneck for turbine equipment.

## Key Uncertainties

- **Hydrogen pipeline supply pressure:** Maintaining equivalent power output on hydrogen requires roughly triple the fuel volume of natural gas. While network developers have indicated that compressor station capacity on the network should be sufficient to avoid the requirement for additional onsite compression at generator sites, further engagement with hydrogen network developers is required to confirm this.
- **Newbuild CAPEX:** CAPEX estimates are based on recent market data, Baringa benchmarks, and a limited set of data provided by stakeholders during interviews. The figures reflect an increase above inflation relative to recent estimates; however, ongoing market volatility introduces a high degree of uncertainty around the accuracy of these estimates.
- **Retrofit CAPEX:** Is informed by limited stakeholder data informed by high-level technical assessments. Accurate estimates of retrofit CAPEX will require detailed site-level studies, and retrofit CAPEX is likely to be highly plant specific.
- **Timelines for commercial launch of turbines:** While OEMs are confident in the technical feasibility of delivering 100% hydrogen-capable turbines by 2030, particularly for smaller units, limited access to hydrogen for full-scale testing remains a constraint to testing systems for commercial launch especially for larger turbine classes with higher fuel demand. Moreover, commercial guarantees and launch timelines will depend on clearer evidence of future market demand including policy developments and investment in upstream hydrogen production, transport and storage across multiple global markets.
- **Optimism bias in project planning and cost estimation:** As with conventional gas power projects, there is a risk of optimism bias in the planning of H2P projects, including underestimation of CAPEX, timelines, and operational challenges. While the degree of bias is not expected to differ significantly between hydrogen and gas projects, the relative novelty and limited commercial experience with hydrogen may still introduce unanticipated technical or delivery risks that are not fully captured in current assumptions.

## 4.2 Reciprocating Engines

### Introduction

Reciprocating engine generators represent a growing source of flexible generation capacity in the UK. Deployment has accelerated over the past decade, particularly in response to the increasing need for fast-responding assets to support system balancing and reserve services.

Reciprocating engines are highly proven technologies, operating in a very similar way to a typical internal combustion engine, but on a much larger scale. A specific site would typically be configured using multiple engine units in parallel to provide flexibility to ramp-up and down output. Individual engine units can range from the sub-1MW scale up to c.12-15MW. Grid-scale natural gas-fired reciprocating engine facilities in the UK typically have capacities up to around 50 MW; however, their modular design allows for larger capacity configurations where suitable sites and infrastructure are available. Until the 2010s, reciprocating engines saw limited deployment in grid-scale power generation due to performance and maintenance challenges relative to turbine technologies. However, with increased adoption, there is a growing international trend toward larger scale reciprocating engine plants on the order of hundreds of megawatts, previously the domain of turbine generators. A prominent example in the UK is the Thurrock Flexible Generation Project, currently in construction, which aims to deliver 450 MW of natural gas reciprocating engine capacity at a single site in Southeast England. [11]

### Main Suppliers

Leading international suppliers of natural gas reciprocating engine equipment for power generation applications include (non-exhaustive): Wärtsilä, MAN Energy Solutions, INNIO Jenbacher, Caterpillar, MWM (a Caterpillar brand), Rolls-Royce Power Systems (MTU). Rolls-Royce were interviewed as part of this study, as were Clarke Energy, a leading UK installer of INNIO Jenbacher systems.

### UK Owners and Operators

Owners and operators of gas reciprocating engine generators in the UK include (non-exhaustive): Arlington Energy, Conrad Energy, Flexitricity, and Statera Energy.

Statera Energy was interviewed as part of this study.

### UK Hydrogen to Power Development Pipeline

Initial stakeholder engagement has identified several potential for hydrogen-fired reciprocating engine developments being considered across the UK:

- **Teesside:** Statera Energy has begun exploratory discussions with its equipment supplier to assess the feasibility of converting its existing 50 MW Teesside Saltholme unit to run on hydrogen, contingent on securing a hydrogen supply from production projects in the region.

- **HyNet:** Progressive Energy reported that at least two new-build sub-50 MW reciprocating engine facilities could be deployed in the North West, with hydrogen supplied via pipeline from the HyNet network.

- **Onsite production and storage concept:** Reciprocating engines were discussed conceptually as a potential option for distributed hydrogen-fired generation outside the HyNet and

Humberside clusters. Stakeholders suggested that these systems could, in theory, be developed before 2030, assuming on-site hydrogen production and storage. Two indicative storage configurations were referenced: low-pressure gaseous storage (around 40 bar), which would avoid the need for onsite compression, and liquid hydrogen storage, which one stakeholder suggested may be less CAPEX intensive than a high pressure gaseous storage system. Such systems could be co-located with renewable generation, though total capacity would likely be constrained by the volume of hydrogen stored on site. One stakeholder indicated an upper bound of around 10 tonnes, based on the assumption that permitting and consenting for storage assets outside industrial sites would become prohibitive beyond this threshold.

Based on these insights, a set of representative system archetypes has been defined for the purpose of CAPEX assessment (Table 12).

**Table 12 Hydrogen to power reciprocating engine archetypes assessed**

| Label | Newbuild / Retrofit | Description | Capacity (MW) | Max. Hydrogen Blend Ratio(s) (vol%) | Storage Solution |
|---|---|---|---|---|---|
| **Retrofit 50MW** | Retrofit | Retrofit of existing system to blended or 100% | 50 | Up to: 20, 60, 100 | Salt Cavern |
| **Newbuild 50MW** | Newbuild | Newbuild system capable of firing on 100% H2 | 50 | 100 | Salt Cavern |
| **Newbuild Distributed (Liquid Storage)** | Newbuild | Newbuild system capable of firing on 100% H2 | 10 | 100 | Liquid |
| **Newbuild Distributed (Gaseous Storage)** | Newbuild | Newbuild system capable of firing on 100% H2 | 5 | 100 | Low pressure (c. 40 bar) gaseous |

For the 50 MW centralised archetypes, deployment is constrained by the need for large-scale hydrogen infrastructure and can realistically occur only after 2030, in line with the expected development of pipeline networks and salt cavern storage. In comparison, smaller-scale distributed systems with onsite hydrogen production could feasibly be deployed ahead of these infrastructure timelines.

## Technology Readiness and Future Outlook

**Retrofit:** Existing reciprocating engine systems can accommodate hydrogen blends of up to 20vol% with only minor modifications to fuel handling and control systems. However, performance and efficiency are increasingly impacted at higher blend levels. Operation at 60% hydrogen typically requires a power derate of around 20%, increasing to approximately 30% for 100% hydrogen firing. As a result, blends above 20% are generally not considered a practical or cost-effective retrofit option for existing assets.

**New-Build Systems:** Hydrogen-capable reciprocating engines are commercially available today, including from Wärsilä, Jenbacher and Rolls Royce, with a CAPEX premium of approximately 10–20% compared to natural gas equivalents. Based on CAPEX estimates for natural gas reciprocating engines. These systems are designed for 100% hydrogen operation but can also run on natural gas.

However, unlike turbines, when a 100% hydrogen-capable unit operates on natural gas, a power derate of 20–30% is expected due to design trade-offs in combustion geometry and system optimisation for hydrogen.

Post-2030, fully fuel-flexible reciprocating engines remain unlikely. Existing blend limits and derating requirements are expected to persist over the medium term, reflecting underlying technical constraints inherent to engine technology related to combustion stability, thermal management, and emissions compliance.

## Cost and Performance Data

Estimated CAPEX for newbuild gas-fired reciprocating engine systems range from £550 - 610/kW at 50 MW scale, and £610–£700/kW at the 5 - 10 MW scale. Full line-item breakdowns are provided in Appendix A.

Table 13 presents the estimated percentage CAPEX uplift for newbuild hydrogen-fired distributed generation systems compared to a natural gas baseline, broken down by line item. These estimates are based on input from OEMs and developers, and include DEVEX increases associated with first-of-a-kind (FOAK) projects.

For distributed systems, the costs of hydrogen production and storage are not included in these figures. These components are treated as separate systems with their own cost structures. Higher DEVEX is still expected for distributed projects overall due to the added complexity of co-developing these elements alongside the generation asset.

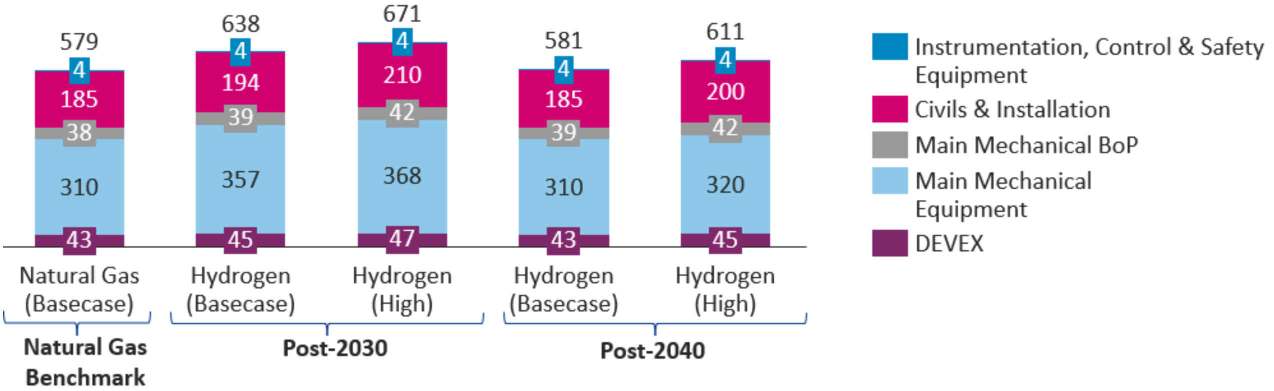
For pipeline-supplied systems, total CAPEX is expected to be broadly comparable to natural gas equivalents, with uplifts driven mainly by the cost of hydrogen-compatible engine equipment.

**Table 13 Estimated CAPEX uplift for hydrogen engine archetypes vs equivalent natural gas systems**

| | % Increase vs newbuild natural gas baseline | | | | |
|---|---|---|---|---|---|
| | **Pipeline Supplied** | | **Distributed (onsite H2-production)** | | |
| | **Post-2030** | **Post-2040** | **Pre-2030 (FOAK)** | **Post-2030** | **Post-2040** |
| **DEVEX** | 5% | 0% | 20% | 15% | 10% |
| **Main Mechanical Equipment** | 15% | 0% | 20% | 10% | 0% |
| **Main Mechanical BoP** | 5% | 5% | 10% | 0% | 0% |
| **Instrumentation, Control & Safety Equipment** | 5% | 5% | 10% | 10% | 5% |
| **EPC** | 5% | 0% | 10% | 0% | 0% |

The resulting CAPEX estimates for a 50MW system are shown in Figure 7:

**Figure 7 Unit CAPEX estimates for 50MW hydrogen-firing reciprocating engine generators (£/kW, 2025)**




Stakeholders interviewed for this study reported that existing engine systems are assumed to be either already 20vol% hydrogen capable by default, or able to be retrofitted to enable blending to 20vol% at no extra costs as part of a standard service. Retrofitting to enable operation on 100% hydrogen was estimated at c.20% of newbuild natural gas CAPEX.

Key performance metrics for typical gas-fired reciprocating engines are presented in Table 14 [12]. Performance is expected to be maintained on hydrogen and hydrogen blends, assuming that the system is operating on the fuel blend to which it is tuned.

**Table 14 Key Performance Metrics for Typical Gas-Fired Reciprocating Engines**

| Parameter | Unit | Central | State-of-the-Art |
|---|---|---|---|
| **Net Efficiency (LHV)** | % | 40 – 45% | 43 – 50% |
| **Hot start-up time** | min | 2 - 5 min | 0.5 - 2 min |
| **Cold start-up time** | min | 10 – 15 min | 5 - 10 min |
| **Average ramp rate** | % Rated Power / min | 20 - 50% (100 for already started engines) | 20 – 50% (100 for already started engines) |
| **Minimum load** | % Rated Power | 20 – 30% | 10 – 20% |

## Barriers to Deployment and Scale-up

High-level barriers to deployment and scale-up are broadly consistent with those identified for turbine generators and were tested through stakeholder engagement. However, for reciprocating engines, the limited capacity for flexible firing on fluctuating blends of hydrogen and natural gas presents a challenge; where turbine systems can mitigate against fuel supply cross chain risk by maintaining the option for firing on 100% natural gas, this is only possible with power derate for hydrogen-capable engines.

## Key Uncertainties

- **Early stage project development:** Whilst stakeholders were able to share high-level insight on planned hydrogen developments, limited specific project-level data could be shared concerning target costs or development timelines.
- **Fuel flexibility and competitiveness versus turbines:** With favourable efficiency and CAPEX estimates, and archetypes available for 100% hydrogen firing, reciprocating engines could present a more attractive option than turbines in certain applications. However, their

competitiveness is highly dependent on the expected availability of hydrogen fuel over the plant's operational lifetime, given the need to tune engines to operate on a specific fuel composition. If a hydrogen-configured plant is required to operate frequently on natural gas or high natural gas blends due to supply constraints, it will need to be derated, constraining dispatch. This could also affect the plant's ability to meet Capacity Market (CM) dispatch obligations if it holds a CM contract. In contrast, turbines are generally more fuel-flexible and can operate across a range of hydrogen-natural gas blends without requiring derating.

- **Scale and site suitability:** The figures presented in this analysis focus on sites with capacities up to 50 MW. However, the ability to scale to the hundreds-of-megawatts range will be a key factor in determining the relative competitiveness of reciprocating engines compared to turbines. At these larger scales, suitability is influenced not only by the availability of sites that can accommodate the relatively large physical footprint of reciprocating engines, but also by trade-offs in maintenance cost and operational complexity, which are not yet well understood. While large-scale reciprocating engine projects are beginning to emerge, their viability depends on securing sufficiently sized and well-located sites, given the modular configuration of engine-based plants.

## 4.3 CHPs

### Introduction

Combined Heat and Power (CHP) technologies generate electricity while simultaneously capturing and utilising the associated waste heat, offering significantly higher overall energy efficiency than separate heat and power production. CHP systems typically combine a prime mover, such as a gas turbine, reciprocating engine, fuel cell, or, in larger-scale installations, a steam turbine within a CCGT plant, with heat recovery equipment to supply both power and usable heat.

In the UK in 2023, CHP systems accounted for 7.6% of total electricity generation, with natural gas providing 66% of the fuel input. Industrial CHP schemes dominate national capacity, most notably refineries, which contributed 35% of total CHP electrical capacity despite comprising less than 1% of the total number of sites. While most heat output from CHP is consumed on-site, around 43% of the electricity generated was exported to the grid. [13]

### Main Suppliers

CHP should be viewed as a system configuration rather than a distinct technology. Accordingly, the major engine and turbine suppliers referenced above remain relevant in this context.

### UK Owners and Operators

A broad range of sectors in the UK utilise CHP, with industrial owners/operators dominating the largest installations, particularly in industries like refineries, chemicals, and food production. Additionally, commercial and public sectors, including hospitals and universities, are also significant contributors. Operators of heat networks such as Vattenfall Heat UK and Vital Energi also operate associated CHP plants.

### UK Hydrogen to Power Development Pipeline

**EET Fuels (49.5MW turbine CCGT + CHP, retrofit):** The EET Fuels hydrogen CHP project, currently under development at the Stanlow Refinery in North West England, targets a

Phase 1 commercial operation date (COD) in 2028. The project comprises 49.5 MW of gas turbine capacity integrated with heat recovery steam generators (HRSG) and supplementary duct firing. The system is designed for fully flexible operation on up to 100% refinery off-gas (ROG), natural gas, and hydrogen, with fuel switching between these different sources achievable in under three minutes. It is intended to supply electricity and steam to the refinery. The refinery site is targeting retrofit in 2027, with the objective of reducing overall carbon emissions from the site. This will include electrification of refinery equipment, increasing site power demand. The CHP project therefore aims to address this demand by supplying power directly to the refinery and is also exploring options for behind-the-meter (BtM) consumption or grid export; should the retrofit be delayed, near-term power supply to the grid or BtM customers is expected to increase. The plant configuration enables recovery of exhaust heat from the gas turbines via the HRSGs, with duct firing used to supplement steam production as required. This allows the system to flexibly increase power dispatch to the grid by temporarily raising duct firing to maintain steam output while exporting additional electricity.

- **Saltend Power Station (1.2GW[10] CCGT + CHP, retrofit):** Saltend is a large-scale CCGT facility made up of three 400MW trains, operating as an integrated Combined Heat and Power (CHP) plant. Steam extracted from the CCGT process is supplied to the adjacent Saltend Chemicals Park, while electricity is exported to the UK grid and used onsite. A FEED study by Mitsubishi has assessed the conversion of two trains (2 x 400MW) to operate on a 30vol% hydrogen blend, supporting decarbonisation while maintaining industrial heat and power supply.

## Requirements and Modifications for Hydrogen Fuelling

For existing CHP systems, the retrofit requirements for hydrogen fuelling are assumed to be equivalent to those necessary for converting the underlying gas turbine or reciprocating engine hydrogen.

## Cost and Performance Data

Cost and performance considerations for hydrogen-fuelled CHP systems are assumed to align with those associated with converting the primary generator, whether a gas turbine, reciprocating engine, or boiler, to hydrogen. We refer to relevant sections of this report, for the appropriate cost and performance information.

## Technology Readiness and Future Outlook

Technology Readiness Levels (TRLs) for combined heat and power (CHP) systems are expected to closely track those of the underlying prime mover technologies—such as turbines, reciprocating engines, or fuel cells. The heat recovery components themselves are generally mature and well-understood, and no material differences are anticipated in the design or performance of heat recovery systems when operating on hydrogen compared to natural gas. As such, hydrogen-fired CHP systems are not expected to face additional technical barriers beyond those already associated with the primary generation technology

[10] *Only 800MW of the site's capacity is being considered for hydrogen retrofit.*

## Barriers to Deployment and Scale-up

**Micro- and small-scale CHPs:** For micro- and small-scale CHPs (e.g., commercial buildings or decentralised energy schemes), hydrogen is not currently a practical fuel option due to fundamental constraints in fuel logistics and infrastructure readiness; these systems are generally sited outside industrial clusters, and therefore beyond the reach of any early hydrogen transmission infrastructure. Interim supply options such as high-pressure hydrogen cylinder delivery or modular electrolysers are capital and space-intensive, with high operational complexity. Their integration into built environments is further hindered by safety, permitting, and maintenance requirements. The lack of economies of scale, combined with increased costs for hydrogen-capable prime movers and safety systems, is expected to render small-scale hydrogen CHP uncompetitive in the near term.

**Assets Integrated into Industrial Sites:** Projects like the EET Fuels Stanlow refinery development are restricted to industrial locations with steam offtake capabilities, such as refineries. While this is an effective approach for refinery decarbonisation, the potential for scaling such projects to provide significant dispatchable power to the grid is limited.

## Key Uncertainties

As outlined in the EET case, CHP systems with steam offtake in industrial settings can flexibly increase dispatch to the grid by temporarily raising duct firing to maintain steam output while exporting more power. However, the associated CAPEX and efficiencies and therefore the business model constraints and key uncertainties for deployment are highly site specific.

Other key uncertainties relating to the CHP architype are discussed in the relevant technology section (e.g. OCGT, reciprocating engines).

# 4.4 Fuel Cells

## Introduction

Fuel cells are electrochemical systems that convert hydrogen into electricity, emitting only water and heat as by-products, with no NOX or CO2 emissions at the point of use. For stationary power generation, two fuel cell technologies are primarily relevant: Proton Exchange Membrane (PEM) fuel cells and Solid Oxide Fuel Cells (SOFCs). Both are under ongoing development for industrial and utility-scale applications.

PEM fuel cells operate at relatively low temperatures (below 80°C) and generate electricity through the electrochemical reaction of hydrogen and oxygen. Their low operating temperature allows for fast start-up and responsive load-following. However, they require high hydrogen purity and careful moisture control, which can affect durability and long-term reliability. In contrast, turbines and reciprocating engines are more tolerant to fuel impurities.

SOFCs operate at significantly higher temperatures (typically 500 to 1,000 degrees Celsius), enabling potential integration with heat recovery systems. However, their slow start-up times, limited ramping capabilities, and susceptibility to thermal cycling present challenges for applications requiring operational flexibility.

As research and engagement found no evidence of near-term deployment of SOFC systems for power generation in the UK, and limited evidence internationally, this section focuses exclusively on PEM fuel cells.

## Main Suppliers

Key international suppliers of PEM fuel cells include: Ballard Power Systems, Plug Power, Cummins, and Doosan Fuel Cell.

SOFC suppliers include: Mitsubishi Power, Ceres, and Bloom Energy.

## UK Owners and Operators

In the UK, use of hydrogen fuel cells for power generation is currently limited to non-grid-connected applications, such as mobile, off-grid, or temporary backup systems. These are typically used on a project-specific basis and operate independently of the national electricity network [14]. At present, there are no operational grid-connected hydrogen fuel cell power generation assets in the UK.

## UK Hydrogen to Power Development Pipeline

HDF, a European hydrogen fuel cell project developer, is exploring options for H2P projects in the UK, including a 40MW system in the HyNet region. HDF's projects fall into two main categories: Renewstable, a small-scale, self-contained hydrogen production, storage, and power generation system; and HyPower, which targets larger, pipeline-connected fuel cell installations.

## Requirements and Modifications for Hydrogen Fuelling

PEM fuel cells operate solely on hydrogen and require high-purity hydrogen for direct use. Unlike other technologies, they do not accommodate blended fuels. Projects using pipeline hydrogen supply would therefore require purification to remove impurities, as contaminants can poison the fuel cell, reducing performance, efficiency, and system lifespan.

## Technology Readiness and Future Outlook

The 80 MW Shinincheon plant in South Korea demonstrates that PEM fuel cells can operate at commercial scale for power generation. However, deployment remains limited due to hydrogen supply constraints and poor cost competitiveness. SOFCs are at a lower Technology Readiness Level (TRL), with fewer real-world demonstrations and greater technical uncertainty at scale.

## Cost and Performance Data

The 80 MW PEM facility commissioned in South Korea in 2021, with a reported total project cost equivalent to c. £215 million in 2025 (c. £2,700/kW) [15]. This estimate is broadly aligned with the limited data provided shared by stakeholders as part of this study.

Hydrogen purity is a critical challenge for pipeline-supplied fuel cell systems, as fuel cells are highly sensitive to contamination. Even trace levels of impurities introduced through the pipeline can irreversibly damage the fuel cell stack. While fuel cell capital costs may decline with wider deployment, the purification system, which is estimated to account for roughly 15% of the total installed cost, is a mature technology and is unlikely to experience significant cost reductions.

Table 15 summarises performance characteristics for PEM fuel cells as relevant to power generation [16].

**Table 15 Key performance metrics for PEM fuel cells for power generation**

| Parameter | Unit | Value |
|---|---|---|

| | | |
|---|---|---|
| **Net Efficiency (LHV)** | % | c.50% (load dependent) |
| **Hot start-up time** | min | < 2 |
| **Cold start-up time** | min | 5 – 10min |
| **Average ramp rate** | % Rated Power / min | >10% |
| **Minimum load** | % Rated Power | 10 - 20% |

## Barriers to Deployment and Scale-up

## Key Uncertainties

Fuel cell CAPEX reductions are contingent on deployment of fuel cell systems at scale by 2030, which remains uncertain due to current market and technology risks.

# 5 Implications for policy development

## Key Cost and Performance Findings for Hydrogen to Power

***Turbines***

- OEMS have indicated 100% hydrogen-capable systems should be available by the early 2030s across the full turbine capacity range, however, commercial launch will occur only in the case of visible market demand such as firm orders from developers, which will happen in parallel with testing and development of the hydrogen-capable turbines, particularly for larger-scale products.
- In the long-term, hydrogen gas turbines are expected to maintain performance as observed for natural gas up to their defined blend capability, which varies by system but typically lies between 30 – 50vol% for existing power generation assets.
- Retrofitting or deploying newbuild 100% capable hydrogen systems ahead of commercial launch of the target turbine is possible but could incur either a power derate (of the order up to 20% for observed projects), implying a proportional CAPEX increase (on a £/MWh basis), or an efficiency reduction of the order <5% LHV relative to the equivalent natural gas archetype. Target deployment timelines should consider this, noting that a firm policy signal targeting a specific archetype could accelerate timelines for commercial launch of products with equivalent performance to current natural gas turbines, driving down CAPEX to levels comparable to natural gas systems. Firm policy signals would provide developers with certainty over the types of projects that could see some level of support, which would in turn enable them to place orders with OEMs – facilitating faster progress towards equivalent performance.
- 100% hydrogen-capable turbine units are expected to see a CAPEX uplift of c.20% relative to natural gas systems in the 2030s, but should approach cost parity with natural gas for an nth of a kind system, given highly comparable technology.
- Pipeline and recently-commissioned CCGT assets, particularly those being designed for hydrogen compatibility from commissioning could present the most cost-effective option for retrofit up to the c.50vol% hydrogen blending capability defined for existing commercially-available turbine systems.

***Reciprocating Engines***

- Reciprocating engines capable of firing on 100% hydrogen are available today with a 10 – 20% CAPEX uplift vs equivalent natural gas systems. Total installed cost for a 100% hydrogen system is estimated to be c.10% higher than the equivalent natural gas system in the near-term, approaching cost parity in the longer term.
- Hydrogen blending into existing systems is possible up to 20vol% with no performance impact. Beyond this, systems must undergo retrofit which will incur a power derate of 20 – 30%. A business model targeting reciprocating engine retrofit archetypes would need to compensate for this capacity loss.
- Relative to turbines, reciprocating engines offer higher efficiencies and response rate. CAPEX estimates also indicate cost competitiveness with turbine systems.
- With favourable efficiency, cost, and the availability of hydrogen-capable engine archetypes, reciprocating engines could present a more attractive option than turbines in certain applications. However, their competitiveness depends on the expected availability of hydrogen fuel over the plant's operational lifetime, given the requirement to tune engines to a specific fuel composition.

- If a hydrogen-configured reciprocating engine plant is required to operate frequently on natural gas or high natural gas blends due to hydrogen supply constraints, it will need to be derated, reducing its dispatchable capacity. This may also affect the plant's ability to meet Capacity Market (CM) dispatch obligations if it holds a CM contract. In contrast, turbines are generally more fuel-flexible and can operate across a wide range of hydrogen-natural gas blends without derating.

***Fuel Cells***

- PEM fuel cells are one of a number of technology solutions to an efficient, rapid response technology which could be applied in peaking applications. CAPEX presents a key barrier, with fuel cell equipment currently estimated at over £1,300/kW compared to c.£500/kW for a 50MW hydrogen-capable OCGT, and total installed system costs more than double that amount for a pipeline-supplied system with hydrogen purification. While stakeholders have cited EU projections suggesting that fuel cell CAPEX could become more competitive by 2030, overall system costs are expected to remain approximately 2–3 times higher than those of turbine or reciprocating engine systems. Hydrogen purification, which is required for pipeline-supplied hydrogen, is a mature technology with limited potential for cost reduction and adds an additional CAPEX of around £485/kW. Future deployment will depend on clearer cost reduction pathways and identification of high load factor applications where efficiency benefits can be effectively leveraged.

## Barriers Identified

1. **Turbine Technology Readiness and Availability**: OEMs are confident that 100% hydrogen-capable turbines can be developed by 2030; however, for larger turbines, limited hydrogen availability for testing presents development challenge. Commercial launch and associated commercial guarantees for systems across the capacity range will depend on demand visibility so cannot yet be confirmed. OEM's generally noted that their global manufacturing capacity (and therefore related build-rates) for hydrogen turbines are very similar to their current natural-gas equivalents.
2. **Geological storage availability**: Power dispatch is expected to become increasingly variable, including for CCGTs, as renewable penetration grows. Blue hydrogen remains the only near-term scalable supply option, but its baseload production profile is potentially less well aligned with the fluctuating demand of power generation. Electrolytic hydrogen further amplifies this misalignment due to renewable intermittency. Large-scale salt cavern storage is required to buffer this supply-demand imbalance for hydrogen fuel. The challenge intensifies for systems targeting 100% hydrogen firing: increasing average hydrogen blend from 90% to 100% has been estimated by one stakeholder to more than double storage needs for some systems, driven by interseasonal demand variability and capacity reserves for extreme events, which in turn constrains availability for other hydrogen users.[11] An appropriate level of flexible firing on natural gas could help to deliver maximum system benefits and optimised allocation of storage capacity
3. **Alignment of policy frameworks**: Given the fundamental dependency on geological storage, alignment of timelines for the Transport and Storage and H2P business models is essential to delivery of any hydrogen to power assets. The exception would be closed loop systems like the

[11] *Figures are based on stakeholder input. Further evidence and modelling are needed to validate these views and assess the influence of hydrogen blend ratio on overall storage requirements.*

Aldbrough Pathfinder project, which could, in principle, proceed without the H2PBM, provided that a Capacity Market contract and Hydrogen Production Business Model contracts are secured.

4. **Regulatory Framework**: A dedicated network code is needed to enable hydrogen pipeline transportation.
5. **Asset Lifespan and Retrofit Economics**: Many CCGT plants, such as ESB Carrington, will be over 14 years into their operational life by 2030, with an expected total lifespan of 25 years. Retrofit capital expenditures must be recovered over a shorter operational window compared to a completely new-build asset.
6. **Power Derate and Efficiency Losses from Retrofit**: Retrofitting turbines commissioned post-2010 is assumed to involve minimal power derate or efficiency loss, consistent with OEM expectations. However, older plants like Rocksavage face significant power derate even at blends up to 30vol%. Such conversions are only economically viable if business models compensate for significant capacity derate. The same applies to all reciprocating engine assets regardless of age for any blend exceeding 20vol%.
7. **Grid connection and electrical infrastructure**: While not hydrogen-specific, several power generation asset developers cited grid connection delays and long lead times for supergrid transformers as likely barriers to deployment for any newbuild assets.
8. **Workforce**: A recurring concern among developers is the limited availability of skilled construction labour, which is already contributing to delays in project timelines for other energy infrastructure projects at current deployment rates. While major developers may mitigate some of this risk through EPC contracts, stakeholders observed that EPC providers are increasingly embedding stricter contingency measures into agreements to protect themselves from potential workforce-related disruptions, resulting in higher capex prices. For H2P projects: specific hydrogen-related skills could present additional constraints for deployment, for example, related to safety systems, certification and testing – both in the design and construction phases.
9. **Interaction with global power markets and policies**: As is apparent from the global long-lead times and high pricing for conventional gas turbines (particularly arising from data-centre demand in the USA) - both demand and policies in other countries will incentivise development and deployment of hydrogen technologies, particularly related to reducing capex costs in the medium to long-term.

# 6 Conclusion

This study has examined the technical readiness, costs, and deployment barriers associated with hydrogen to power technologies in the UK. The analysis covered gas turbines, reciprocating engines, combined heat and power (CHP) systems, and fuel cells, drawing on stakeholder engagement, and performance data collated from the literature.

**Turbines**

*Technical*

- **Turbines present the most fuel flexible technology**, with OEMs are targeting the commercial release of fully fuel-flexible hydrogen/natural gas turbines, capable of operating on natural gas, hydrogen, or any blend, by the early 2030s, across the full range of turbine capacities. This can enable projects to deploy hydrogen-ready systems ahead of widespread hydrogen availability and provide resilience against supply disruptions in a developing market
- **Hydrogen capable turbines deployed ahead of commercial release of the relevant turbine model may need to be derated by up to 20%** when operating on hydrogen, meaning fuel flow to the system is restricted, limiting power output compared to the system's rate capacity when operating on natural gas. Any derate requirement would increase overall system operational costs, by limiting access to the turbine's full power potential.
- **Most early hydrogen turbine generators will require natural gas for start-up**, so must maintain a natural gas grid connection. Only one major global turbine OEM is expected to offer turbine systems in the 2030s which can start-up on hydrogen.

*Costs*

- **Stakeholders indicated that newbuild hydrogen-capable systems will carry a CAPEX premium of up to 10%** on the total installed cost of the system compared to natural gas equivalents. This uplift reflects OEM efforts to recover R&D costs, and the additional costs associated with configuring Balance of Plant components for hydrogen.
- **Estimates were provided as percentage uplifts versus equivalent natural gas equivalent systems which presents challenges in estimating the absolute costs** associated with delivering hydrogen-capable turbine systems in the current market. The gas turbine sector is currently under pressure from rising power demand driven by AI data centres. One OEM suggested supply chains could scale within 2–3 years, but prolonged constraints would likely increase total installed costs and limit availability of hydrogen-capable turbines.
- **The CAPEX required to retrofit existing turbine generators could be expected to vary widely by plant depending on turbine model** and the condition of existing Balance of Plant equipment. Feasibility studies for hydrogen conversion are still in the feasibility stages, and operators have been reluctant to share indicative cost estimates, recognising that preliminary figures may differ significantly from actual conversion costs. For older assets nearing end of life, retrofitting for hydrogen may offer limited cost advantages over newbuild, as the scope and expenditure can approach that of a full repowering.
- **OEMs indicated that hydrogen turbines are expected to follow the same Operations and Maintenance (O&M) schedules as equivalent natural gas turbines**. As a result, non-fuel-related OPEX is anticipated to remain broadly consistent with natural gas systems.

**Reciprocating Engines**

*Technical*

- **Reciprocating engines which can operate on 100% hydrogen fuel are commercially available today**. However, these are significantly less fuel flexible than turbines. The system's rated power capacity applies only when they are operating on the system's primary fuel (i.e. natural gas or hydrogen). Operating on alternate fuels or blends beyond c.20vol% requires significant power derating of 20–30%. Retrofitting existing natural gas reciprocating engines for 100% hydrogen similarly incurs capacity derates.
- **Reciprocating engine systems are more vulnerable to hydrogen supply disruptions** than turbine systems, as they can switch to natural gas only by operating at a reduced output.

*Costs*

- **Based on limited stakeholder insights, the total installed CAPEX for a 100% hydrogen reciprocating engine system is expected to be 10–20% higher** than for current natural-gas systems. This corresponds to an estimated uplift of approximately £60–120/kW for a new-build facility.
- **Retrofits to accommodate up to 20 vol% hydrogen blends can be completed as part of standard servicing with no additional cost**. However, retrofitting an existing natural-gas system to operate on 100% hydrogen is expected to incur a CAPEX of roughly 20% of new-build costs (around £120/kW) and would require the system to be derated by about 30% relative to its natural-gas nameplate capacity.

**Combined Heat and Power (CHP)**

*Technical*

- **For a limited number of industrial sites using gas turbine CHP systems to supply both power and process steam, the plant can temporarily increase power output** by raising thermal input in the steam generation section to maintain steam production while exporting additional electricity. Switching to hydrogen in these cases allows decarbonisation of the industrial process while also delivering dispatchable low-carbon power to the network.
- **Only a limited number of industrial sites operate in this configuration, and consequently this approach offers targeted benefits** rather than representing a broadly scalable option for hydrogen-based power generation across the network.

**Fuel Cells**

*Technical*

- **Fuel cells can offer high efficiency, rapid response, and zero point emissions**. Unlike turbines and reciprocating engines, they can operate only on hydrogen and are therefore fully dependent on a secure hydrogen supply.
  Fuel cells are highly sensitive to contaminants in the hydrogen supply, so pipeline-delivered hydrogen must undergo purification, requiring dedicated on-site purification equipment

*Costs*

- **Fuel cells face near-term deployment challenges due to high capital costs**. Based on limited publicly available and stakeholder data, total installed CAPEX for a grid-scale fuel cell system is estimated to exceed £2,500/kW.

- **Future deployment depends on clearer pathways to capital cost reductions**, and on identifying use cases requiring high load factor operation, where efficiency benefits can be best leveraged to offset high capital costs.

**Hydrogen Storage**

- **Hydrogen production profiles, both green and blue, will likely be misaligned with the mid-merit and peaking roles currently served by natural gas generators** across CCGTs, OCGTs and reciprocating engines. As the share of variable renewable generation increases, these assets are expected to operate increasingly in peaking mode.
- **If hydrogen is to replicate the role currently played by natural gas on the network, hydrogen storage will be essential** to ensure fuel is available for dispatch when needed. At the scale required for grid applications, onshore salt cavern storage is currently the leading option, but its availability is limited to regions with suitable geology such as Cheshire, Humberside, and Dorset.
- **According to insights from one stakeholder, storage requirements will increase sharply with the number of hours the system is expected to operate on 100% hydrogen**. This analysis indicates that requiring 100% hydrogen for all dispatch could more than double storage capacity compared with allowing natural gas blending during periods of prolonged low renewable output to achieve an approximate 90% average hydrogen energy share.

**Hydrogen to Power Projects in Development**

- **Among the H2P projects identified through interviews, the predominant archetype comprises new-build or retrofit CCGT projects with capacities exceeding 800 MW**, representing five potential sites. Other potential projects include a retrofit reciprocating engine facility, and a newbuild peaking facility which may use OCGT or reciprocating engine technology.
- **The majority of projects are concentrated in the North West and Humber clusters**, coinciding with prospective salt cavern storage developments and planned blue hydrogen production (HPP1/HPP2, H2H Saltend).
- **While CCGT operators have actively engaged through feasibility assessments and planning exercises that offer valuable insights for future development, the current pipeline of projects may not reflect eventual market composition**. As H2P matures, other generation archetypes may become increasingly viable.
- Hydrogen-ready new-builds should not necessarily be interpreted as a near-term commitment to hydrogen power generation. This is because, with respect to new-build projects, developments must be designed for decarbonisation readiness, via hydrogen or CCS, in accordance with the Decarbonisation Readiness framework.
- **All project developer stakeholders engaged emphasised that their projects were strongly dependent on policy and regulatory alignment** across hydrogen production, transport, storage, and power generation, which is essential to enable coordinated deployment and to mitigate cross-chain risks across the value chain.

# 7 Appendix A – Natural Gas Generation CAPEX Benchmarks

Details of the cost components for each line item are presented in Table 16. Please note that financing costs and interest during construction are not included in these cost estimates.

**Table 16 Breakdown of Cost Components by CAPEX Line Item**

| CAPEX Line Item | Components |
|---|---|
| **DEVEX** | • Developer (in-house) costs<br>• Land Acquisition (purchase or lease)<br>• Pre-licensing (permits, environmental assessments), Technical & Design (i.e. pre-FEED / FEED)<br>• Planning, Regulatory, Licensing & Public Enquiry |
| **Main Mechanical Equipment** | • Gas Turbine + Generator<br>• Steam Turbine (CCGT-only) |
| **Main Mechanical BoP** | • Fuel Handling System<br>• Turbine auxiliary systems<br>• Exhaust System<br>• HRSG, Cooling Tower & Condenser (CCGT-only) |
| **Instrumentation, Control & Safety** | • Software / Sensors & interface to software |
| **EPC (Engineering, Procurement & Construction)** | • Site preparation, construction, buildings & structures<br>• Project management<br>• Owner's Engineer |
| **Power Grid Connection Infrastructure** | • Transformers, circuit breakers, busbars, etc. |

CAPEX estimates for natural-gas fired OCGT assets for 50 and 100MW systems are summarised in Table 17.

**Table 17 CAPEX estimates for natural gas-fired OCGT assets by capacity - Baringa Analysis (£, 2025)**

| CAPEX Component | Unit | 50Mwe | | | 100MWe | | |
|---|---|---|---|---|---|---|---|
| | | Low | Central | High | Low | Central | High |
| **DEVEX** | £/kW | 45 | 50 | 55 | 40 | 42.5 | 45 |
| **Main Mechanical Equipment** | £/kW | 280 | 305 | 330 | 250 | 270 | 290 |
| **Mechanical BoP** | £/kW | 100 | 112.5 | 125 | 75 | 100 | 125 |
| **Instrumentation, Control & Safety** | £/kW | 5 | 6.5 | 8 | 4 | 5.5 | 7 |
| **EPC** | £/kW | 170 | 200 | 185 | 150 | 190 | 170 |
| **Total** | **£/kW** | **600** | **659** | **718** | **519** | **588** | **657** |

CAPEX estimates for natural-gas fired CCGT assets for a 1200 and 900MW system are summarised in Table 18

**Table 18 CAPEX estimates for natural gas-fired CCGT assets by capacity - Baringa Analysis (£, 2025)**

| CAPEX Component | Unit | 900 MWe | | | 1,200 MWe | | |
|---|---|---|---|---|---|---|---|
| | | Low | Central | High | Low | Central | High |
| **DEVEX** | £/kW | 60 | 70 | 80 | 55 | 65 | 75 |
| **Main Mechanical Equipment** | £/kW | 240 | 265 | 290 | 200 | 230 | 260 |
| **Mechanical BoP** | £/kW | 170 | 190 | 210 | 150 | 170 | 190 |
| **Instrumentation, Control & Safety** | £/kW | 4 | 5 | 6 | 3 | 4 | 5 |
| **EPC** | £/kW | 330 | 415 | 500 | 300 | 375 | 450 |
| **Total** | **£/kW** | **804** | **945** | **1,086** | **708** | **844** | **980** |

CAPEX estimates for natural-gas fired 10MW and 50MW reciprocating engine assets are summarised in Table 19.

**Table 19 CAPEX estimates for natural gas-fired reciprocating engine assets by capacity - Baringa Analysis (£, 2025)**

| CAPEX Component | Unit | 10MWe | | | 50 MWe | | |
|---|---|---|---|---|---|---|---|
| | | Low | Central | High | Low | Central | High |
| **DEVEX** | £/kW | 46 | 50.5 | 55 | 40 | 42.5 | 45 |
| **Main Mechanical Equipment** | £/kW | 320 | 340 | 360 | 300 | 310 | 320 |
| **Mechanical BoP** | £/kW | 43 | 46.5 | 50 | 35 | 37.5 | 40 |
| **Instrumentation, Control & Safety** | £/kW | 4 | 5 | 6 | 3 | 3.5 | 4 |
| **EPC** | £/kW | 200 | 215 | 230 | 170 | 185 | 200 |
| **Total** | **£/kW** | **613** | **657** | **701** | **548** | **579** | **609** |

# 8 Appendix B – Technical considerations for hydrogen firing of turbines

**Table 20 Key turbine and BoP components to be assessed when retrofitting natural gas-fired assets or designing newbuild generators to operate on blended or 100% hydrogen fuel**

| Component | Reason for modification | Modification required to natural gas-fired systems | Relevance to existing and newbuild assets |
|---|---|---|---|
| **Fuel Supply System** | Lower volumetric density | • Additional hydrogen compression<br>• Increase diameter of fuel supply pipework to accommodate higher volumetric flow | • Fuel supply lines in newbuild assets designed for hydrogen readiness can handle hydrogen flowrates by default. For other assets, pipework suitability highly site dependent.<br>• Supply pressure / flowrate from planned hydrogen networks remains uncertain. UK developers have indicated flowrate will allow 100% H2 firing without derate. |
| | Embrittlement | • Hydrogen-resistant fuel supply pipework and fuel compressors | • Suitability of existing systems site dependent. Plants with existing stainless steel pipework can potentially avoid upgrades. |
| | Blended fuel supply | • Blending skid required to facilitate fuel mixing (footprint approx. 7–30 m²) | • Required for all sites considering blending, unless blended fuel received from the transmission network at low hydrogen blend ratios |
| | Reliability of fuel supply | • Onsite hydrogen storage<br>• Hydrogen compression to supply onsite buffer storage | • Only relevant to distributed small-scale facilities not connected to pipeline hydrogen supply. 10 tonnes estimated maximum onsite storage for these system. |
| | Flammability | • Nitrogen purge system to prevent oxygen mixing with hydrogen, particularly during startup / shutdown | All |

| | | | |
|---|---|---|---|
| **Burner and Combustion Chamber** | Combined effect of $H_2$ combustion properties (see Table 4) | • Burner replacement / modification | Any blend exceeding the rated hydrogen capability of the specified target turbine model |
| | Higher Flame Speed | • Replacement of fuel injection nozzles | • Site specific, dependent on blend ratio |
| | Lower Flame Luminosity | • Replace flame detector with hydrogen-compatible system e.g. catalytic gas detector [17] | • Low cost modification relevant to all systems handling hydrogen |
| | Adiabatic Flame Temperature (increased NOX emissions) | • Possible Selective Catalytic Reduction (SCR) retrofit / upgrade requirement | • OEMs aim to deliver DLE / sequential combustion systems that maintain NOX below permitting thresholds. Retrofit systems may require SCR. |
| | Water Vapour Exhaust | • Integrate corrosion-resistant material into hot gas path regions (e.g. nickel superalloys) | • Site specific, dependent on blend ratio |
| | Energy Density | • Real-time monitoring of blended gas energy content (Wobbe meter or equivalent) | • Relevant for all blends. Already installed in many systems |
| **Heat Recovery Steam Generator – *CCGT only*** | Adiabatic Flame Temperature (increasing NOX emissions) | • Install / upgrade SCR for higher NOX processing<br>• Adjust ammonia injection in SCR to reduce ammonia slip<br>• Select temperature-resistant SCR catalyst | • Site specific, dependent on blend ratio and turbine capabilities |

| | | | |
|---|---|---|---|
| | Adiabatic Flame Temperature (increased and unstable NOX emissions) | • Adjust ammonia injection control system with closed-loop dynamic control based on real-time $NO_x$ concentrations<br>• Install dual-stage SCR (stage 1: NOX reduction, stage 2: residual ammonia reaction) | • Site specific, dependent on blend ratio and turbine capabilities |
| **Instrumentation and Control** | Distinct combustion characteristics | • Additional sensors for hydrogen detection and blended fuel operation monitoring | • Low cost modification relevant to all systems handling hydrogen |
| **Buildings** | Propensity of H2 to rise, owning to low density | • Review ventilation to ensure proper air exchange, adding roof openings where necessary | • Low cost modification relevant to all systems handling hydrogen |
| **Fire & Explosion Protection** | Lower Density | • Adapt explosion protection concept, adding blast zones where necessary | • All sites require review of ATEX zoning requirements for hydrogen handling |

# 9 Appendix C – NOX Control

NOX emissions from combustion processes are typically measured in relative concentration units, such as parts per million by volume (ppmv), representing the number of NOX molecules per million molecules in the exhaust gas. To ensure consistency and comparability across systems, measurements are standardized by referencing dry exhaust gas (with water vapor removed) and normalizing to 15% oxygen by volume.

Hydrogen's higher flame temperature and reactivity make meeting NOX emission limits more challenging. Developers and OEMs engaged for this study estimate that NOX emissions from hydrogen-fired turbines could be up to twice those of equivalent natural gas systems. However, this may be an overestimate due to biases introduced by current measurement conventions.

Specifically, measuring emissions in relative units (ppmv) can introduce distortion in the case of hydrogen combustion. Unlike methane (CH4), which produces both CO2 and water vapour, hydrogen combustion yields only water vapour and NOX. When water is removed to create a "dry" exhaust sample, the remaining gas volume is significantly reduced, artificially inflating the reported NOX concentration. Although hydrogen combustion does result in a real increase in NOX emissions per unit of energy due to its flame characteristics, recent studies suggest that measurement practices may overstate NOX emissions by up to 37.2% in hydrogen-fired systems.

In the UK, gas turbine emissions are regulated under the Environmental Permitting (England and Wales) Regulations 2016, which transpose the EU Industrial Emissions Directive (IED) into domestic law. Large gas turbines (thermal input >50 MW) are subject to Best Available Techniques (BAT) Conclusions for Large Combustion Plants. For natural gas-fired turbines, BAT-associated emission levels (BAT-AELs) for NOX typically range from 15–50 mg/Nm³ (at 15% O2), equivalent to approximately 8–25 ppmv. Operators converting existing turbines or installing new hydrogen-capable units will need to work closely with the Environment Agency, Natural Resources Wales, or SEPA to ensure compliance. Adhering to BAT-AELs is mandatory for new or substantially modified plants.

***NOX Control Options for Hydrogen-Fired Turbines***

Several combustion and aftertreatment technologies can be deployed to control $NO_x$ emissions:

- **Wet Low Emissions (WLE):** Injects water or steam into the combustion zone to reduce flame temperature and suppress NOX formation. While WLE enables 100% hydrogen firing, it reduces thermal efficiency due to added heat losses and auxiliary loads. It also involves high water consumption—potentially around 480 m³/day for a 60 MW turbine—which may be problematic in water-scarce areas.
- **Dry Low Emissions (DLE):** Uses lean premixed combustion to limit flame temperature and NOX production without water injection. DLE systems are common in modern gas turbines and are typically validated for up to 30 vol% hydrogen, though OEMs are actively developing variants capable of higher blends and 100% hydrogen operation.
- **Sequential Combustion:** Features a two-stage combustion process where fuel is burned in a primary combustor and reheated in a secondary stage. This allows for precise temperature control, reducing peak flame temperatures and NOX formation. It is particularly well suited to high hydrogen blends and is being explored as a pathway to 100% hydrogen firing in modified natural gas turbines

- **Selective Catalytic Reduction (SCR):** A post-combustion treatment that injects ammonia or urea into the exhaust gas, converting NOX into nitrogen and water via a catalyst. SCR is widely used to ensure compliance with stringent NOX limits, particularly where combustion-based mitigation is insufficient.

# 10 Appendix D – Turbine hydrogen capabilities by OEM

**Table 21 Summary of Hydrogen Capabilities Across Major Turbine OEM Portfolios [18]**

| Supplier | Model | Power (MWe) | H2 Blend Limit (vol%) | Combustor Type | Efficiency (%) |
|---|---|---|---|---|---|
| **Ansaldo** | GT36 | 563 | 70 | Sequential | 42.8 |
| | GT26 | 370 | 45 | Sequential | 41 |
| | AE94.3A | 340 | 40 | Sequential | 40.3 |
| | AE94.2 | 191 | 40 | Sequential | 36.8 |
| | AE64.3A | 78 | 40 | Sequential | 36.4 |
| **GE** | 9HA | 448-571 | 50 | DLE | 42.9 - 44 |
| | GT13E2 | 195-210 | 30 | DLE | 38 - 38.5 |
| | 9E | 132-147 | 100 | WLE[12] | 34.3 - 36.9 |
| | 6F | 88 | 100 | DLE | 36.8 |
| | 6B | 45 | 100 | WLE | 33.4 |
| **Mitsubishi** | M701J | 440-570 | 30 | DLE | 42.3 - 44 |
| | M701F | 380 | 30 | DLE | 41.9 |
| | H-100 | 100-120 | 30 | DLE | 38.3 |
| | H-25 | 40 | 30 | DLE | 36.2 |
| | | | 100 | WLE | - |
| **Siemens Energy** | SGT5-9000L | 593 | 50 | DLE | 43 |
| | SGT5-8000H | 450 | 30 | DLE | 41.2 |
| | SGT5-4000F | 329-385 | 30 | DLE | 41 |
| | SGT5-2000E | 198 | 30 | DLE | 37.6 |
| | SGT-800 | 45-62 | 75 | DLE | 38.4 - 41.1 |
| | SGT-750 | 41 | 40 | DLE | 40.5 |
| | SGT-700 | 35 | 75 | DLE | 38 |
| | SGT-600 | 25 | 75 | DLE | 33.6 |

[12] *DLE B-and E-class turbines developed by GE Vernova with 100vol% hydrogen capability targeting commercial release in 2026.*

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