HYDROGEN GAS TURBINES

ETN Global Report

October 2024

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Executive Summary

Hydrogen gas turbines are preparing to take on a central role in the carbon neutral energy system

With a strong commitment and cooperation between gas turbine original equipment manufacturers, users, and academia, it has been demonstrated that the efficient and low-emission use of hydrogen in gas turbines is within reach. This technology is thus positioning itself as an important and technologically mature building block for the provision of dispatchable power and grid stability to complement variable renewable energy sources. Moreover, the possibility to adapt existing gas turbine assets and infrastructure to use hydrogen can drastically reduce the carbon footprint of power generation as well as other gas turbines users (e.g., oil and gas, cogeneration, compressor stations, maritime transport, etc.) in the short-term to support the energy transition.

There are concrete plans for the necessary development of low-carbon hydrogen infrastructure, and the first infrastructure projects have been launched, so that the availability of low-carbon hydrogen by 2030 seems realistic. And the available storage capacities also appear to be sufficient to ensure the necessary decoupling of production and use. This means that there are no longer any fundamental technological showstoppers.

To fully unlock the potential of zero-emission hydrogen gas turbine technology in a future energy landscape, research and development activities are specifically needed to overcome combustion instabilities and to further develop (premixed) combustion technologies maintaining low NO_x emission for up to 100% hydrogen. Changes in the hot gas properties for hydrogen combustion also require development of new materials and cooling technologies for hot gas path components. Government funded projects to address some of these challenges are ongoing, however further developments will likely be necessary to expand the use of low-carbon hydrogen across the global gas turbine fleet.

The deployment of new technology in a real-world environment will be important to overcome in the demonstration phase. Appropriate demonstration projects are required throughout Europe, and worldwide, to verify the feasibility of new gas turbine and hydrogen supply system solutions. The retrofit of existing gas turbines needs to be evaluated on a case-to-case basis for given hydrogen levels, either in the pipeline network or blended on site, considering modifications in the fuel supply, controls, instrumentation, combustion, exhaust/HRSG, and safety systems.

In addition to the further technological development of gas turbines and power plant components, the next step must be to develop adapted operating concepts, regulations, and financial models for the future energy system so that hydrogen gas turbines can take on their role, in which overall installed capacity remains essentially constant and in some cases increases, but capacity factors reduce. These models will need to account for hydrogen gas turbines that may operate in the future for fewer hours than today's natural gas CCGTs, but yet will urgently need to be available when the wind does not blow or the sun does not shine.

The global gas turbine community is prepared to meet these challenges with safe, reliable, and compliant hydrogen gas turbines for the energy transition and the net-zero future.

Acknowledgments

The ETN Global Hydrogen Gas Turbines Report has been issued by the Energy & Turbomachinery Network (ETN Global), as part of the activities of the ETN Global Hydrogen Working Group. This report is an update of the first version which was issued in 2020 [1], considering the most recent results and developments in this field. The report was directed by Peter Kutne (Head of Department Gas Turbines, DLR) with the support of the ETN Global secretariat.

The knowledge and expertise of the ETN Global members who contributed to this report added significant value to the publication. We would like to thank especially the main contributors (in alphabetical order): Andrea Ciani (Ansaldo Energia), Adnan Eroglu (Siemens Energy), Luc Gooren (Engie Laborelec), Felix Guethe (Phoenix BioPower), Jim Harper (EPRI), Peter Kutne (DLR), Geert Laagland (Vattenfall), Bobby Noble (EPRI), Jon Runyon (Uniper), Jens Walter (BASF), Mitch Webb (EPRI).

We also acknowledge the ETN Global Members who shared valuable information on the relevant technological solutions in Chapter 5 of this report: Ansaldo Energia (Enrico Bianchi, Francesco Ferando, and Mauro Moretto), Baker Hughes (Paolo Bruttini and Egidio Pucci), Mitsubishi Power (Jaime de Ojeda), PSM (Jeffrey Benoit), Siemens Energy (Adnan Eroglu), and Solar Turbines (Jean-Luc di Liberti and Marc Vignal).

1. Advantages of hydrogen gas turbines

According to the International Energy Agency (IEA) scenario to achieve Net Zero Emissions by 2050 (NZE) [2], the global decarbonisation of the power generation sector can be achieved by significantly increasing the share of Renewable Energy Sources (RES) such as wind and solar. However, these renewable sources provide a fluctuating electricity supply which needs to be balanced by other forms of reliable, affordable and sustainable power generation. In the "Global Hydrogen Review" [3], the IEA identifies low-carbon hydrogen as a driver of the clean energy transition, including in the power sector. Therefore, hydrogen gas turbines will be one of the carbon-neutral technologies supporting society to achieve the ambitious energy and climate targets. Indeed, hydrogen gas turbines will enable deep carbon emissions reduction for the long-term, while providing the dispatchable capability that is necessary for the further expansion and integration of RES.

In January 2019, the gas turbine industry committed to develop gas turbines capable of operating with 100% hydrogen by 2030 [4], thus fully supporting the transformation of the European gas grid into a renewable-based energy system by overcoming the technical challenges of hydrogen's use and ensuring a swift transformation. At COP28 in Dubai, the parties committed to transition away from unabated fossil fuels in energy systems. A global "Net Zero Roadmap" [5] was sketched by the IEA in which hydrogen and hydrogen-based fuels play an essential role in achieving net-zero emissions with rapid progress needed by 2030. The prediction of "95% reduction by 2040 in the unabated use of fossil fuels" [5] in the electricity sector requires rapid changes to power generation installations and necessitates development and implementation of new carbon-free technologies. In this roadmap, the NZE scenario suggests "natural gas-fired generation peaks in the mid-2020s before starting a long-term decline" and the "capacity additions of dispatchable renewables triple by 2030" [5]. The IEA's NZE scenario [2] also requires the adoption of hydrogen capability for gas turbines and corresponding infrastructure to achieve this ambitious target. Indeed, the IEA notes that the electricity sector is "an important driver of hydrogen demand" [2] in the NZE and estimates that 8 Mt/year of low-carbon hydrogen will be used globally for power generation by 2030 and 88 Mt/year by 2050 [2]. This is a significant scale-up in hydrogen use for power generation as the amount required by 2050 equals the total amount of all hydrogen production globally in 2020 and represents 17% of all low-carbon hydrogen production by 2050. Consequently, hydrogen infrastructure must be scaled up and investments are becoming a reality, for example in Germany and The Netherlands, discussed further in Chapter 2.

Significant progress towards a net-zero energy system is already being made. In 2023, a record fall in coal, gas and CO_2 emissions was observed in the European Union (EU) as RES took major steps forward [6]. Natural gas power generation in Europe is declining as fossil fuels contribute less to the electricity mix, thus emissions will fall at a faster rate towards the EU's 2030 reduction targets. Also, the IEA predict a historic turning point could arrive soon in the global use of coal for power with its overall share estimated to reduce to the lowest levels on record by 2026 [7].

This indicates that the role of gas turbines in a changing electricity grid, dominated by fluctuating RES, is shifting in the midterm from baseload operation to peaking applications and grid services. The value generation is expected to move toward dispatchable power providers including gas turbines running on renewable fuels such as hydrogen to enable deep decarbonisation of power generation.

Gas turbines already fulfil the crucial balancing role in the energy system. By extending their fuel capabilities to include low-carbon hydrogen, gas turbines can contribute in the following ways during the energy transition period and in long-term energy strategies:

- Flexible and dispatchable gas turbines are proven technology, well-suited for frequent starts, and able to provide a fast response to grid demands, making them complementary to variable RES.
- Today, combined-cycle gas turbines (CCGTs) are the cleanest form of thermal power generation. Indeed, for the same amount of electricity generated, CCGTs running on natural gas emit 50% less CO_2 emissions than state-of-the-art coal-fired power plants.

- For a transition period, mixing renewable gas (e.g., low-carbon hydrogen, biogas, or syngas) with natural gas enables further reduction in net CO_2 emissions. This can be achieved by direct injection in gas pipelines or blending at the power plant.
- By 2030, the gas turbine industry is committed to enable gas turbines to run entirely on renewable gas fuels and therefore deliver capabilities for 100% carbon neutral, dispatchable power generation. The ensuing objective being to implement power plants maintaining high thermal efficiency in combined-cycle configuration.

Hydrogen gas turbines would complement the intermittent nature of RES by enabling significant energy storage and dispatchable power available for long periods. Hydrogen can be produced via electrolysis ("green hydrogen"), using excess renewable power during periods of abundant wind and daylight, or by natural gas reformation combined with carbon capture ("blue hydrogen"). In this context, blue hydrogen can be seen as an initiator to create sufficient hydrogen supply in the short-term and enable the creation of hydrogen infrastructure, including long-duration storage. The scalability of gas turbines from small decentralised to large centralised systems allows for adaptation to the local hydrogen production and local capacities. In the long term, hydrogen gas turbines can be an enabler for long-duration, seasonal and regional energy storage when integrated with power to gas (P2G) technologies as shown in *Figure 1*.

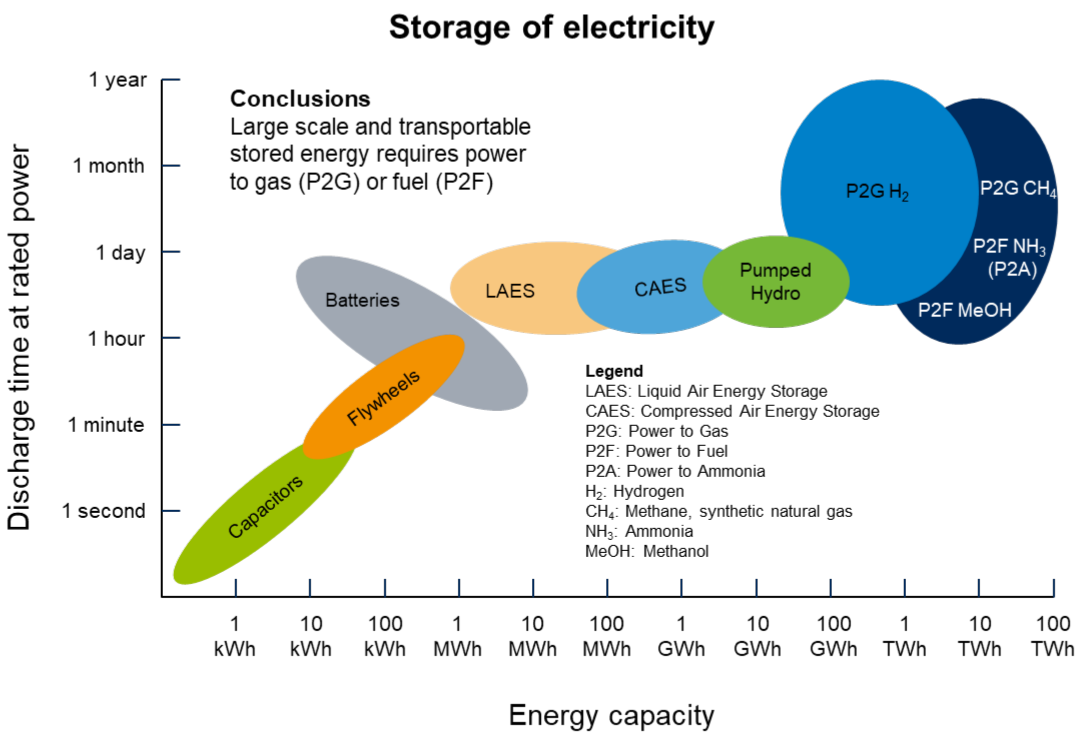


Figure 1 – Electricity storage technology map.

While volumetric hydrogen percentage in a blend with natural gas is often used as a unit in public discussion, the amount of CO_2 avoided is not linearly related with the hydrogen content in the blend, as shown in *Figure 2* which uses methane (CH_4) as a surrogate for natural gas. Due to this non-linear dependency, the use of higher hydrogen content fuels must be enabled as soon as possible to maximise the impact on CO_2 reduction. However, the relation between fuel reactivity (posing the technical challenge) and volumetric share of hydrogen is also non-linear [8]. Thus, the amount of carbon avoided as well as the technical challenge increases steeply at high volumetric shares of hydrogen. It should also be noted that the volumetric percentage of hydrogen is also not linearly related with its energy fraction of the blend, which can create confusion. **Therefore, only volumetric hydrogen percentage is used in this report.**

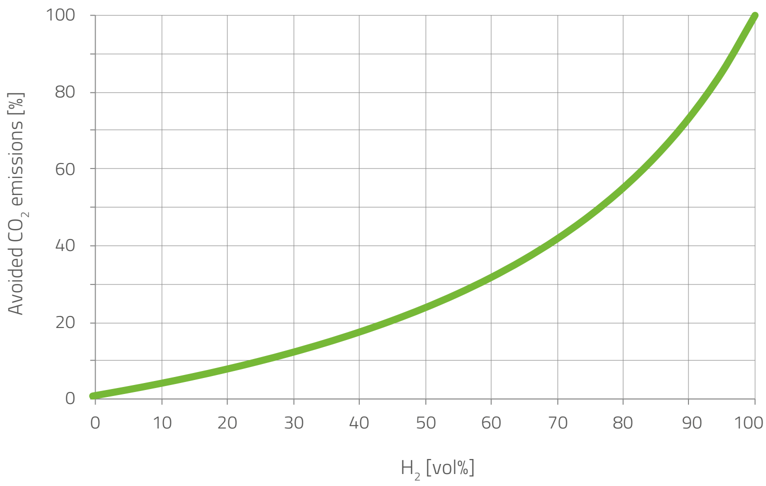


Figure 2 – Avoided CO_2 emissions vs volumetric hydrogen content in the methane/hydrogen mixture.

Utilising the existing natural gas infrastructure

Today, gas turbines use the robust and flexible natural gas infrastructure to source their fuel. With appropriate modifications, a blend of hydrogen with natural gas, or even pure hydrogen, can be transported within this existing infrastructure, which makes the system reusable without major expenditure. For example, an existing 12 km natural gas transport pipeline operated by Hynetwork (a subsidiary of Gasunie) in The Netherlands was modified and placed into commercial hydrogen operation in 2018 between the Dow and Yara chemical plants [9]. This concept can be replicated in other regions in the short-term to utilise a blend of natural gas and hydrogen in gas turbines to reduce carbon emissions. Furthermore, there are strong activities in Europe to build a transnational hydrogen network and activities in the different countries. For example, a new and retrofitted piping infrastructure for 100% hydrogen is planned to be ready in Germany by 2037. At least regionally, high hydrogen contents for gas turbine peaking plants seems to be realisable within the early 2030s. More details about the necessary infrastructure are discussed in Chapter 2.

100% emission compliance for nitrous oxides (NO_x)

Current gas turbines can already burn pure hydrogen using diffusion combustion, however this can generate significant NO_x emissions requiring the use of a combustion diluent (e.g., water or steam) or post-combustion selective catalytic reduction (SCR) for NO_x control. For this reason, research and development activities are nowadays focused on low NO_x hydrogen combustion technology, with the potential to substantially reduce NO_x emissions in line with low-NO_x natural gas combustion systems developed over the past decades [10]. In terms of thermal efficiency and power output, differences between current gas turbines and hydrogen turbines, both with low-NO_x technology, would be marginal. This could include new plant concepts with competitive performance for gas turbine applications beyond the energy transition.

To enable a fair and energy-based comparison between fuels, a different normalisation procedure for NO_x emissions following international standards is discussed in Chapter 3 along with other important considerations for hydrogen combustion in gas turbines. Without following this procedure, the normalised NO_x emissions from hydrogen combustion can be quoted up to 40% higher than for natural gas without any change in the absolute amount of NO_x emitted into the atmosphere [11]. This issue puts the frequently reported increase in NO_x emissions for hydrogen into perspective, however low-NO_x hydrogen combustion technology developments are still ongoing.

Retrofitting existing gas turbines

The design of hydrogen gas turbines can rely to some extent on existing gas turbine technology. There is no need to design and manufacture entirely new gas turbines for hydrogen combustion in the transition period for blending hydrogen and natural gas. Chapter 4 discusses this topic in more detail, but many existing gas turbines can be retrofitted to either partially or fully burn hydrogen. This conversion would delay large capital spending and save time in switching large fleets of current gas turbines to hydrogen. The development of retrofit solutions for existing gas turbines will be a key enabler for the implementation of hydrogen gas turbine technology. The first steps can initially be achieved with relatively small modifications to existing combustors to allow co-firing of hydrogen with natural gas. Further modifications may allow higher percentages of hydrogen blending to significant fractions and operation beyond the limits of existing fuel specifications. Increased field experience will enable further developments, such as new types of combustors allowing up to 100% hydrogen firing.

An additional benefit of developing and deploying hydrogen gas turbine technology resides in the potential for a new lifeline of existing equipment. Indeed, there are state-of-the-art gas turbines sitting idle or being underutilised in many European countries. Keeping these power plants in operation would also make a significant contribution to society and industry, by ensuring security of electricity supply and maintaining a workforce which would otherwise either be laid off or shift to other sectors. This does not exclude new-build gas turbines plants from being developed and optimised for renewable fuels and meeting the needs of a future carbon-free electricity market. To further elaborate current hydrogen capabilities and development pathways, Chapter 5 provides the state-of-the-art for retrofit and new-build hydrogen gas turbines from the major gas turbine original equipment manufacturers (OEMs).

Sector coupling for high efficiency and deep decarbonisation

The production of industrial heat is one of the largest carbon emitters worldwide. To reduce CO_2 emissions from these sectors, waste heat from hydrogen gas turbines in combined heat and power (CHP) plants can be used. By coupling hydrogen CHP gas turbines with other industries (e.g., chemicals and refineries), further decarbonisation and high efficiency can be achieved.

Wider hydrogen deployment

Hydrogen gas turbines can stimulate commercial demand for large volumes of low-carbon hydrogen, thus contributing to a reduction in hydrogen production costs and to its wider deployment in multiple sectors. Further cost reductions across the whole hydrogen value chain can be achieved through R&D. In this regard, government funding schemes for hydrogen gas turbine R&D can be a key contributor towards a hydrogen society. Cross-sector collaboration is also needed to eliminate the barriers for the wider deployment of hydrogen-based infrastructure and solutions. Numerous R&D projects and demonstrations of hydrogen gas turbine technologies are ongoing, as shown in Chapter 5, setting the foundation for rapid deployment as low-carbon hydrogen becomes readily available for power generation applications.

Comparison of hydrogen power generation technologies

In a renewable electricity grid, hydrogen can be utilised with several competing power generation technologies which vary in efficiency, flexibility, investment cost (CAPEX) and operational cost (OPEX). Depending on the application, several hydrogen technologies are considered competitive. For example, while hydrogen fuel cells provide high-efficiency power generation for smaller decentralised applications, the high CAPEX of fuel cells for large-scale applications would make fuel-flexible hydrogen gas turbines attractive to provide grid services on the MW and GW scale. *Table 1* shows a qualitative comparison of large-scale (> 10 MW) hydrogen-based power generation technologies including open cycle gas turbines (OCGT), combined cycle gas turbines (CCGT), proton exchange membrane fuel cells (PEMFC), solid oxide fuel cells (SOFC), and internal combustion engines (ICE). Depending on the requirements of the specific application, different technological solutions will be advantageous. The best solution will depend on the load cycle, mobility requirements, costs, and other factors such as heat integration.

Table 1 – Qualitative technology comparison for large-scale (>10 MW) hydrogen-based power generation – advantage (+), disadvantage (-), neutral (0).

	OCGT	CCGT	PEMFC	SOFC	ICE
CAPEX	++	+	--	-	0
OPEX	+	++	0	-	++
Efficiency	+	++	+	++	+
Fuel Flexibility	+	+	--	-	+
Fast response	+	0	++	--	++

2. Pre-Conditions for Hydrogen Power Plants

2.1. Introduction

When hydrogen is used as a fuel for gas turbines, the required quantities will be significant. To deliver hydrogen at this scale implies that a pipeline infrastructure will be needed between hydrogen production facilities, import terminals, or storage and main consumers like gas turbines, (petro-)chemical, and steel industry. Another key requirement is the availability of hydrogen production facilities. Finally, it is expected that the future production and consumption of hydrogen will not necessarily be synchronised, so large-scale storage facilities for hydrogen will be needed. This chapter provides a more in-depth view on these elements. All elements are not only needed from a technical perspective, but also to enable the development of a mature hydrogen market, in which hydrogen will be a commodity similar to natural gas and electricity.

2.2. Hydrogen production

The main options for hydrogen production can be summarised as follows:

- Electrolysis of water
  Excess renewable electricity (mainly wind and solar) is used to produce hydrogen from water by means of electrolysis. This is designated as **green hydrogen**. The typical specific electricity demand per kg of hydrogen produced is around 50 kWh, resulting in an efficiency of around 65% (LHV). From an energy system perspective, direct use of electricity, is preferred where possible. Therefore, green hydrogen production should come from excess renewable electricity (i.e., any electricity that cannot be used directly in a particular process or application).

  This also implies that green hydrogen production via electrolysis will fluctuate in time. Another consequence is that when excess renewable electricity is available in the system, gas turbines for power production will typically not be in operation. Therefore, the production of green hydrogen and its utilisation for power production will not occur at the same time, so availability of hydrogen storage is required.

Project examples:

- RWE Eemshydrogen in Eemshaven (NL); 50 MW electrolyser;
  https://www.rwe.com/en/research-and-development/hydrogen-projects/eemshydrogen/
- Vattenfall Ijmuiden Ver Beta (NL); 2 GW wind and 50 MWp solar combined with <1 GW electrolyser;
  https://group.vattenfall.com/press-and-media/pressreleases/2024/vattenfall-and-copenhagen-infrastructure-partners-awarded-ijmuiden-ver-beta-offshore-wind-farm
- Uniper Energy Park Bad Lauchstädt (GER); 30 MW electrolyser combined with storage;
  https://www.uniper.energy/projects-and-cases/energy-park-bad-lauchstadt

- Methane reforming

  The methane in natural gas can be reformed into hydrogen in combination with carbon capture and storage (CCS). This is designated as **blue hydrogen**. Typical efficiency for these processes is around 70% (LHV). Methane reforming plants are typically operated as base load plants. In a renewable energy system, the expectation is that gas turbines will operate as flexible dispatchable assets for a limited number of hours per year, due to over capacity of RES. This will result in a fluctuating hydrogen demand in time, creating a mismatch between production and demand. Therefore, storage of blue hydrogen will also be needed. For blue hydrogen used in the chemical and steel industries, a more continuous demand is expected.

Project examples:

- H-Vision; Rotterdam (NL) two plants of 750 MW_{H2}, initial feedstock will be refinery gases.
  https://www.h-vision.nl
- H2M; Eemshaven (NL) 1 GW_{H2}, feedstock natural gas.
  https://www.equinor.com/where-we-are/the-netherlands#linde-announcement
- BlueHyNow; Wilhemshaven (GER), 600 MW_{H2}, feedstock natural gas.
  https://wintershalldea.com/en/who-we-are/ccs-and-hydrogen/energy-hub-wilhelmshaven

- Ammonia imports

  It is expected that hydrogen demand in Northwest Europe will be greater than the amount that can be produced in the region. Import of hydrogen from regions with more suitable conditions for renewable electricity production will be required to cover the demand. Typical regions could include North Africa, Middle East, Australia, or South America.

  The most suitable way to transport low-carbon hydrogen over long distances (5000 km) from those regions to Northwest Europe is by means of ammonia. Low-carbon hydrogen and nitrogen from air can be converted into ammonia via the Haber-Bosch process. Ammonia can then be more readily shipped as a liquid at atmospheric pressure and a temperature of -33 °C. This is already a standing practice on a large scale in the fertilizer industry. After arriving in Northwest Europe, ammonia can be used directly as a feedstock for chemical industry (e.g., fertilizers), as a fuel, or can be cracked into nitrogen and hydrogen. When hydrogen is separated from the mixture, purity needs to be ensured. The nitrogen can be used or vented to atmosphere, and the hydrogen can be introduced into local hydrogen infrastructure.

  Ammonia cracking is also a continuous process, so hydrogen storage facilities will be required to align hydrogen use with future gas turbine power generation load profiles.

Project examples:

- Brunsbüttel (GER); RWE;
  https://www.rwe.com/forschung-und-entwicklung/projektvorhaben/projektstandort-brunsbuettel/
- Rotterdam (NL); OCI;
  https://www.portofrotterdam.com/en/news-and-press-releases/oci-expands-import-terminal-for-green-ammonia
- Wilhelmshaven (GER); Uniper;
  https://www.uniper.energy/solutions/energy-transformation-hubs/energy-transformation-hub-northwest/green-wilhelmshaven

2.3. Hydrogen infrastructure

In Europe, the gas grid transmission system operators (TSOs) are working together on the European Hydrogen Backbone (EHB). In the EHB Implementation Roadmap [12], an overview is given of 40 concrete projects by EHB TSO members, representing 31500 km of hydrogen pipelines with expected commissioning prior to 2030. The scale of the network is given in *Figure 3*. Future EU Hydrogen Transmission Network Operators (HTNOs) of the EHB have organised themselves in the non-profit European Network of Network Operators for Hydrogen (ENNOH) according to the EU Hydrogen and Decarbonised Gas Market Package, which was adopted in May 2024 [13].

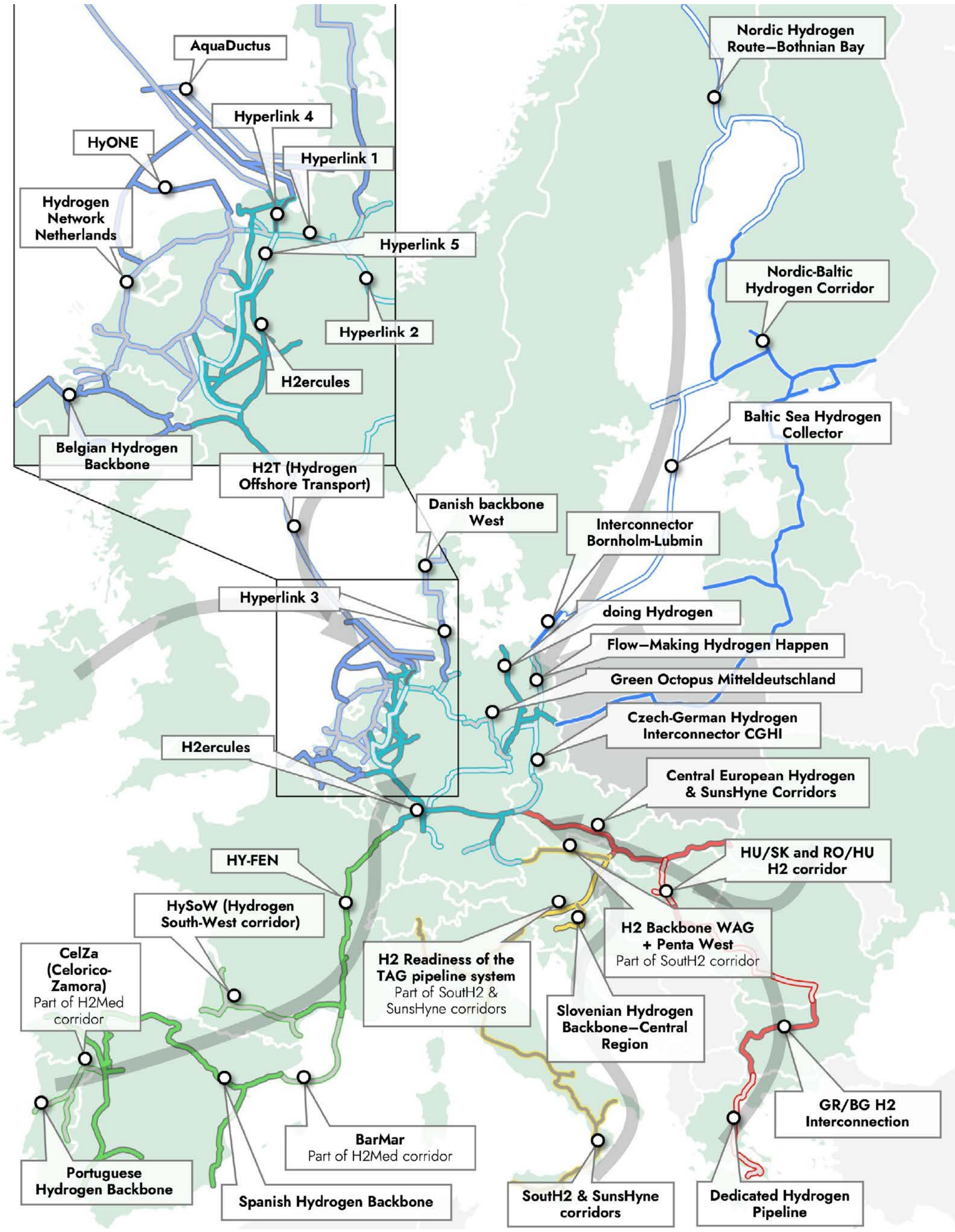


Figure 3 – Development of European Hydrogen Backbone until 2030 [12].

A more specific example of hydrogen infrastructure development is underway in The Netherlands. In other countries, similar developments are ongoing with the aim of implementing together to create the EHB. The TSO in The Netherlands is Gasunie, which is 100% owned by the Dutch government. Hynetwork, a 100% subsidiary of Gasunie, has the assignment to create a national hydrogen network in The Netherlands. Five industrial clusters will be connected to each other, to other countries, and to hydrogen storage, production, and import locations. The aim is to complete the network by 2030, as shown in *Figure 4*. The hydrogen network will be created, to a large extent, by converting existing natural gas infrastructure. A portion of the hydrogen pipelines will be new. Pipeline gas compressor stations and appendages will be replaced.

Figure 4 –National hydrogen backbone in The Netherlands by 2030 [14].

On 27 October 2023, the realisation of this hydrogen network officially started with the construction of the first 30 km pipeline connecting the Maasvlakte industrial park to the Pernis (petro-)chemical cluster [15].

In the United Kingdom, the National Transmission System (NTS) is owned by National Gas. Project Union aims to create a hydrogen backbone for the UK by the early 2030s [16]. Approximately 1500-2000 km of existing natural gas pipelines in the NTS will be repurposed and new hydrogen pipelines will be built to connect strategic hydrogen production and storage sites with industrial clusters in England, Scotland, and Wales. This represents ~25% of the UK's natural gas NTS and includes an interconnection with the EHB through the existing Bacton Gas Terminal connection to The Netherlands, as shown in *Figure 5*. Alongside this project, National Gas is also working on the Future Grid project [16], which is a high-pressure hydrogen test facility, including a gas turbine-driven compressor station, to demonstrate the safety case of using 2%, 5%, 20%, and 100% hydrogen in the repurposed NTS.

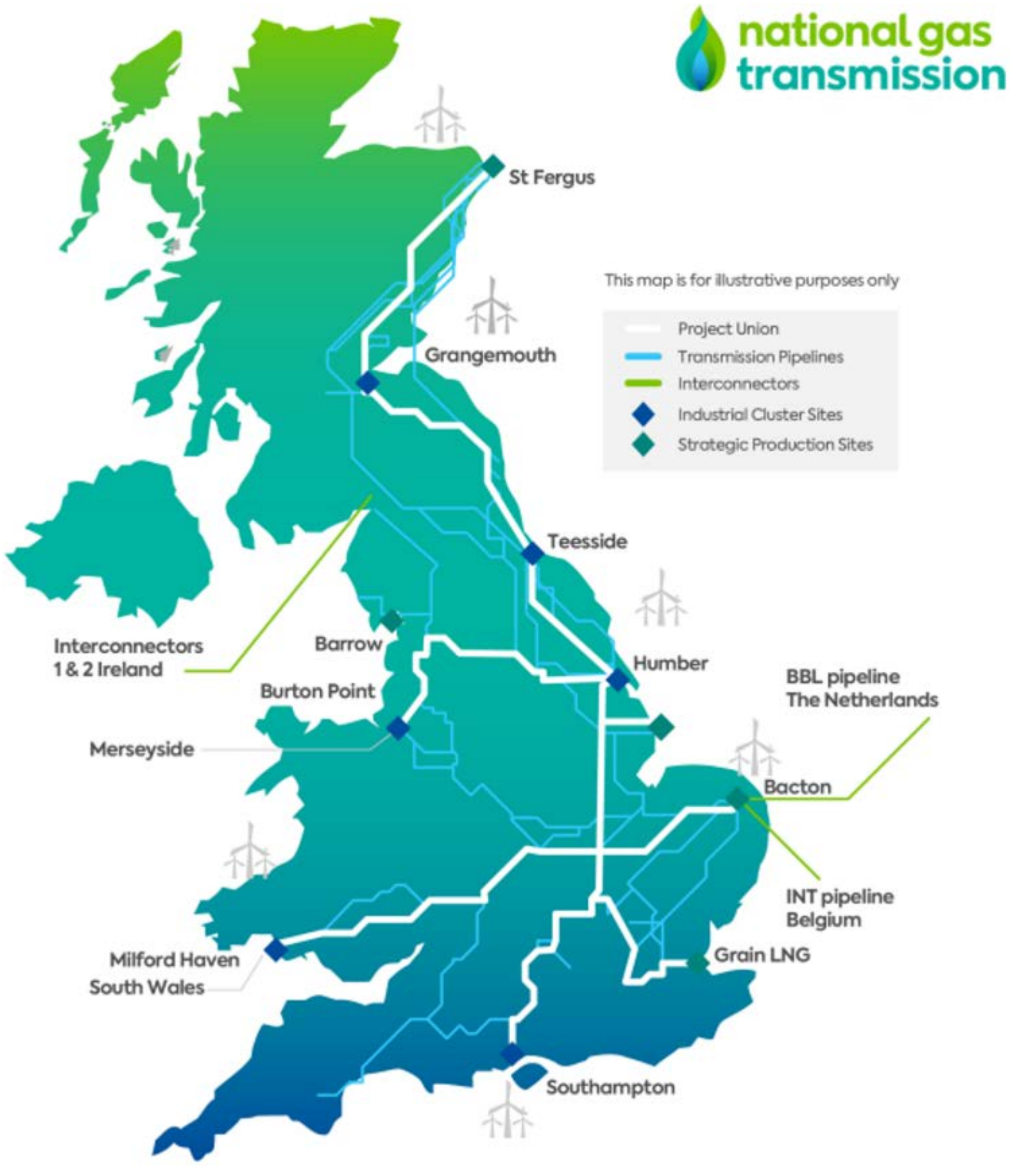


Figure 5 – Project Union proposed national hydrogen backbone in the UK [16].

In Germany, the TSOs have joined together to develop a hydrogen transformation plan. The so-called hydrogen core network is to cover 9700 km and connects ports, industrial sites, storage facilities, and power plants [17]. An overview of the network is given in *Figure 6*. Around 60% of the network will consist of converted natural gas pipelines. Originally planned to be ready in 2032, the network is delayed by five years to 2037 due to problems in the financing [18]. In the H_2ercules project, OGE and RWE are planning to build hydrogen infrastructure, including production, storage, import, and 1500 km of pipeline from the North Sea to southern Germany by 2030 [19], which will also include connection points to other European countries such as Norway, The Netherlands, Belgium, France, and the Czech Republic.

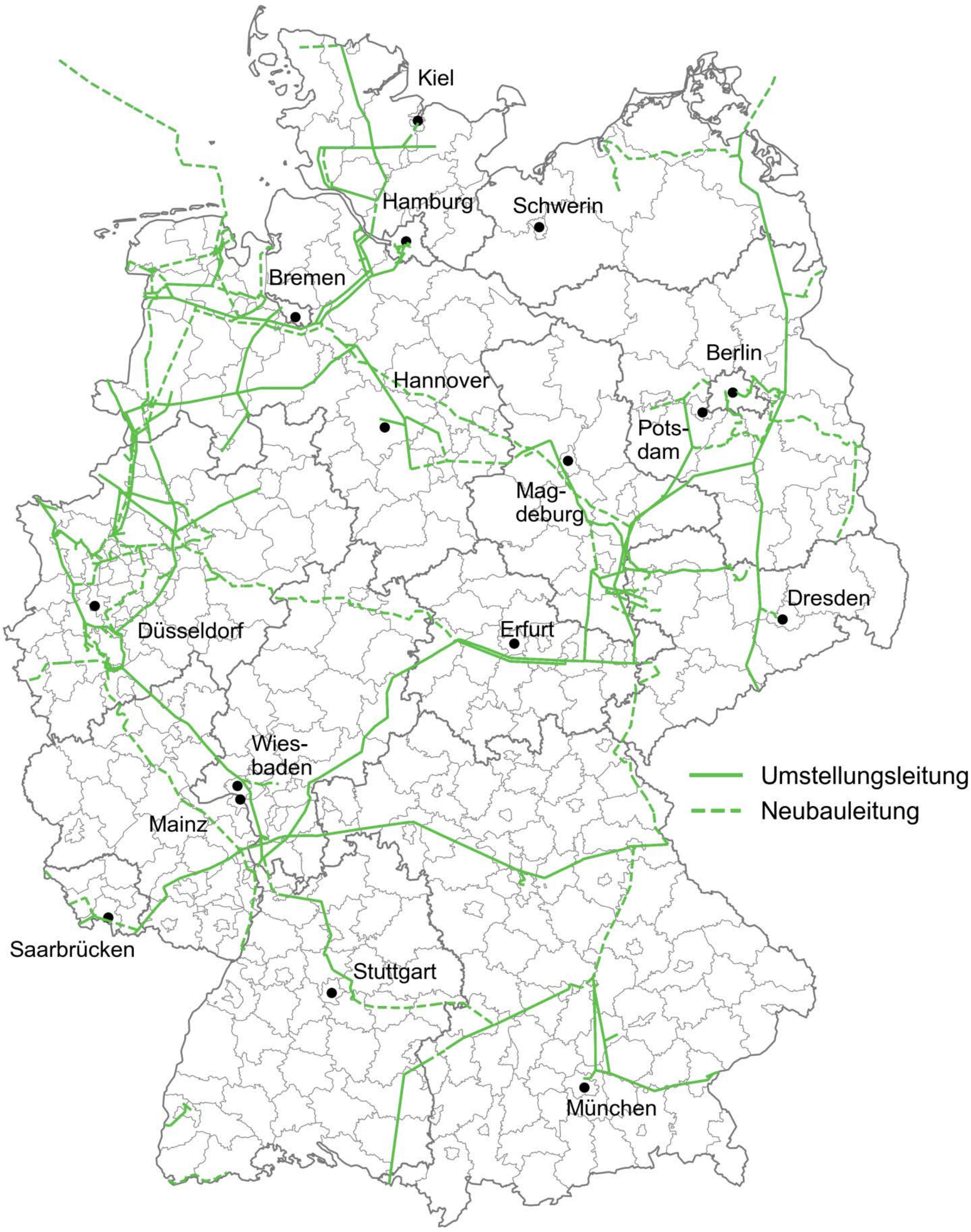


Figure 6 – Overview of the planned hydrogen core network in Germany [17].

2.4. Hydrogen storage

As mentioned earlier in this chapter, the utilisation of hydrogen in industry and power generation is unlikely to be synchronised with the production process for green hydrogen, blue hydrogen, or hydrogen imported as ammonia. Therefore, large-scale hydrogen storage facilities are inevitable.

Storage systems based on pressure vessels or multi-tube arrangements are only suitable for small- to mid-sized peak load gas turbine power plants in terms of cost. For large-scale storage of hydrogen, underground salt caverns offer the most promising option for mid-merit and large gas turbines owing to their low investment cost, high sealing potential and low cushion gas requirement [20]. The overall technical storage potential across Europe is estimated at 85 PWh_{H2}, 27% of which includes only onshore locations. However, this capacity decreases to 7.3 PWh_{H2} for onshore storage within a 50 km distance from shore. Germany has the highest technical onshore storage potential, with a value of 9.4 PWh_{H2}, located in salt domes in the north of the country. Norway has 7.5 PWh_{H2} of offshore storage potential only, located in the subsurface of the North Sea Basin [20].

In a statement by the German National Hydrogen Council [21], an estimate is made for the required hydrogen storage capacity in Germany. In 2030, the estimated hydrogen demand is about 71 TWh. Typically, 6% of the demand should be storable, meaning that approximately 5 TWh of storage capacity will be required. In 2050, it is expected that the required hydrogen storage capacity in Germany should be between 47 and 73 TWh. So, it fits well in the potential storage capacities calculated by Cagalayan et al. [20]. However, the investment plans for hydrogen storage facilities in Germany are currently lagging [21].

Project examples:

- Hystock; Zuidwending (NL) Gasunie First cavern of 216 GWh_{H2} to be operational in 2028; https://www.hystock.nl/en
- Krummhörn (GER); Uniper; Pilot project 600 MWh; https://www.uniper.energy/de/hydrogen-pilot-cavern

2.5. Other required conditions

Besides creating the technical infrastructure for the production, transportation, and storage of hydrogen, the following conditions must be fulfilled to enable a successful introduction of hydrogen as fuel for flexible, dispatchable power generation:

- Development of a clear business model for a successful mature hydrogen market. This entails clear technical and commercial roles and responsibilities. For example, in May 2024, South Korea launched one of the first clean hydrogen power generation tenders in the world, which will enable up to 6500 GWh/year of electricity produced from clean hydrogen (i.e., pure hydrogen, hydrogen blended with natural gas, or ammonia-coal co-firing) with 15-year contracts [22]. In Europe, the H2Global Foundation is pursuing a different approach, using auction-based mechanisms and subsidies in an attempt to even out the difference between supply and demand prices for hydrogen and thus enable a market ramp-up [23].
- A review of the financial boundary conditions required for a viable hydrogen business case. For example, a review of grid fees and levies for electricity used in electrolyser plants or subsidy schemes for hydrogen production and storage facilities.
- A capacity mechanism for CO_2-neutral, flexible, and dispatchable power generation (e.g., hydrogen gas turbines) to address the limited number of operating hours. It shall be noted that, especially in those operating hours, the availability of sufficient flexible power generation capacity is of the utmost importance for the stability and security of the electricity system.

3. Hydrogen Combustion

In this chapter, the current state of the art is described for combustion of pure hydrogen and natural gas/hydrogen blends, including diffusion flames with nitrogen or steam dilution and lean premixed systems. In addition, previous international research efforts on this topic are summarised, spanning technology readiness levels (TRL) from feasibility research to pilot projects. For further detailed information, ETN Global has published a publicly available position paper on this subject [10].

This chapter also discusses practical considerations to consider for combustion and controls systems. In particular, the challenges associated with autoignition, flashback, thermoacoustics, and NO_x emissions when burning hydrogen in gas turbines are addressed, and the associated research needs to address these challenges are described.

3.1. State-of-the-art

Diffusion flames with nitrogen or steam dilution

Combustion systems with diffusion flames and nitrogen, water, or steam dilution can operate today with up to 100% hydrogen. Nevertheless, these systems have several disadvantages, including an efficiency penalty compared to systems without dilution, higher NO_x emissions compared with lean premixed technology, and additional complexity associated with diluent injection leading to potentially high capital and operational costs. In the case of large gas turbines running in a combined cycle or CHP configuration, steam dilution performs significantly better than nitrogen dilution with respect to emissions reduction and plant efficiency. The efficiency penalty is reduced if steam and water can be recovered in the cycle or a humidified cycle can be used.

While diffusion combustion systems can operate with hydrogen, in most cases a separate start-up fuel (i.e., diesel or natural gas) may be needed. This may be necessary due to the requirements for purging of fuel and diluent pathways as well as the complexities of the open-loop control of gas turbine start-up. In contrast, the closed loop temperature control of a gas turbine once it is loaded allows operation on a wider range of fuels and fuel heating values. Compared to gas turbines operated on natural gas or diesel, significant hardware modifications in the auxiliary system are needed to handle the increased volumetric fuel flow rate of hydrogen for diffusion combustion systems. Compressor surge margin issues can be handled by either compressor modifications or by reducing the inlet air mass flow using variable inlet guide vanes, if available.

Lean premixed systems

Lean premixed combustor technology has the benefit of reduced NO_x and CO emissions without the use of a diluent. However, lean premixed technology developments are still ongoing to enable high hydrogen blends or pure hydrogen capability.

The maximum allowable hydrogen concentration in lean premixed combustors varies significantly across gas turbine types as different combustion technologies are employed by each OEM. Fuels with significant hydrogen content are carefully evaluated by each OEM, and the applicability of lean premixed systems is assessed case-by-case considering the requirements of each specific project.

The current maximum allowable amount of hydrogen for different lean premixed gas turbines is up to 30-50% for heavy duty engines (e.g., H-class or F-class), 50-75% for small to medium gas turbines (e.g., industrial gas turbines (IGTs) and aeroderivative gas turbines), and 20% for micro gas turbines (MGTs), although this can vary by OEM. The different ranges of maximum hydrogen content are related to different firing temperatures and combustion technologies (e.g., micro-mixing, swirl-stabilised, jet-stabilised, axial fuel staging, or combinations of these technologies) used in the different GT classes and combustor types. Examples of hydrogen capabilities in low-NO_x combustion systems from a variety of gas turbine OEMs are given in Chapter 5.

Development of combustion systems which can operate across the full range of blends from 0 to 100% hydrogen is ongoing at several OEMs, and many have development plans to have 100% hydrogen capable dry low emissions (DLE) systems available by 2030 [4]. However, a DLE combustion system capable of handling pure hydrogen is not currently commercially available. Additional R&D activities to achieve this target are ongoing and further efforts will be needed. The development of combustion systems that can handle the full range of 0 to 100% hydrogen blended with natural gas, including the ability to start-up on pure hydrogen, is even more challenging but necessary to ensure security of electricity supply if fluctuations in hydrogen fuel supply occur in the future.

3.2. Challenges and research needs in hydrogen combustion

In the transition period to a hydrogen-based energy system, fuel-flexible gas turbines need to utilise blends of hydrogen and other gaseous fuels, such as natural gas. Combustors need to cope with a wide range of natural gas-hydrogen mixtures as well as fast changes in the overall fuel composition. In the medium-term, fuel-flexible gas turbine combustion systems need to be developed which are capable of burning blends containing higher amounts of hydrogen than possible today (refer to the OEM discussion in Chapter 5). In the long-term, gas turbine combustion systems offering full fuel flexibility (i.e., any blend of hydrogen and natural gas up to 100% hydrogen) need to be developed, which requires intensive R&D activity in order to pave the way for such a technology.

DLE technology has the potential to enable fuel-flexible operation from 0 to 100% hydrogen with low emissions, and initial demonstrations are promising (e.g., as shown with the Siemens Energy SGT-400 gas turbine in the HYFLEXPOWER project [24]). However, further development efforts are ongoing to derive technical solutions with respect to the following challenges associated with high hydrogen content in the fuel:

- Flashback
  Burning hydrogen-rich fuels inherently increases the risk of flashback because of the higher flame speed and shorter ignition delay time of hydrogen compared to natural gas. Flame speed and ignition delay time are also a function of combustion system inlet air temperature and pressure. Thus, gas turbines with higher power output and efficiency, operating at higher pressures, are more susceptible to flashback. Hydrogen combustion systems require higher velocities in the regions where fuel and air are mixed to ensure protection against the high flame speed of hydrogen. Additional monitoring methods may need to be developed for overheating or damage protection because of flashback-initiated flame stabilisation in undesired locations (e.g., fuel-air premixing section). In some cases, burners are instrumented with thermocouples if more reactive fuels are used. In advanced, highly efficient gas turbines more complex burner designs are needed, and therefore this method of protecting burners may become challenging and expensive. The methods of detecting and preventing autoignition events leading to flashback are more critical when increasing the hydrogen fraction in the fuel blend.

- Thermoacoustics
  Compared to natural gas flames, hydrogen flames exhibit significantly different thermoacoustic behaviour. This is due to higher flame speed, shorter ignition delay time, and distinct flame stabilisation mechanisms resulting in different flame shape, position, and reactivity. Therefore, combustion dynamics (i.e., self-sustained combustion oscillations at or near the acoustic frequency of the combustion chamber) in modern gas turbines operated on hydrogen-rich fuels are expected to change compared to natural gas operation. This may result in changes to combustion dynamics frequencies and amplitudes depending on the system design, natural acoustic modes, baseline dynamic frequency, and amount of hydrogen in the blend. Undesired phenomena, such as combustion instabilities, flashback, and lean blow out, are likely to occur not only at steady conditions,

but also during transient operation, e.g., when rapid power changes are required and/or the fuel composition changes. Hydrogen blending could exacerbate these transient issues. Refer to *Figure 7* below which shows an example of thermoacoustic damage to a gas turbine combustor operating on natural gas [25].

In order to develop stable combustion systems for hydrogen-rich flames, various measures are required to avoid high pressure pulsations. In addition, the turbulent flame speed of hydrogen is pressure dependent (unlike that of natural gas), which means that low-TRL testing strategies based on atmospheric pressure rigs (e.g., the prediction of engine thermoacoustics via the measurement of flame transfer functions) is not possible.

Hence, in addition to a deeper understanding of the physical mechanisms contributing to combustion dynamics, real-time, reliable monitoring and control systems are required to make hydrogen combustors more efficient and flexible. Addressing this challenge will help to ensure hydrogen gas turbines are available to operate when called upon by the grid.

Figure 7 – Combustor damage due to high-frequency (2350 Hz) thermoacoustic instabilities due to inappropriate tuning of the machine [25].

- ## NO_x emissions

For DLE systems, NO_x is controlled by reducing the regions of the flame with high fuel to air ratios. These "un-mixed" zones contribute to higher NO_x emissions than would be generated for a perfectly premixed system. In a diffusion combustion system, the chemical reaction of fuel and air occurs at the point of contact between the two fluids and thus at near-stoichiometric conditions with an equivalence ratio of 1. This causes diffusion combustors to generate a high combustion temperature peak, which would require more diluent to maintain NO_x levels when switching from natural gas to hydrogen. In contrast, DLE systems have a much lower peak temperature due to their premixed nature. Thermal NO_x generation is exponentially related to combustion temperatures. Thus, DLE systems limit the unmixed, high temperature regions of a flame that contribute to NO_x formation. When burning hydrogen, NO_x production is higher than with natural gas (at the same equivalence ratio) due to the relative increase in flame temperature. However, with improved premixing, control of residence time, and fuel staging, NO_x production with hydrogen can theoretically be on par with natural gas as the peak flame temperatures can be reduced. As advanced, fuel-flexible designs enable improved fuel and air premixing, NO_x emissions can be reduced for hydrogen, natural gas, and their blends.

In addition, an updated NO_x emissions reporting procedure for hydrogen gas turbines is required to enable a fair comparison between hydrogen and natural gas. The current normalisation method for correcting volumetric NO_x emissions to reference conditions increases the apparent emission value from hydrogen combustion by up to 40% compared to natural gas [11]. This is a consequence of the normalisation to the dry flue gas volume and referring to O_2 consumption (at 15% O_2) rather than to released energy. Energy related units such as $mgNO_2$/MJ allow a fair comparison without requiring correction. While this correction compensates up to 40% of the apparent higher NO_x emissions for 100% hydrogen, it does not conceal the technical difficulty to burn hydrogen and the necessity to improve burner design for high hydrogen contents to enable safe and compliant operation.

3.3. Other combustion related challenges

Gas composition monitoring

Compared to burning natural gas at the same thermal power, a larger volumetric fuel flow rate is needed when burning hydrogen due to its lower volumetric LHV. Traditionally, Wobbe Index (i.e., higher heating value divided by the square root of the gas specific gravity), is the most commonly used parameter for specifying the acceptability of a gaseous fuel in a combustion system. In general, the advantage of using the Wobbe Index is that for a given fuel supply, combustor conditions (i.e., inlet temperature and pressure), and control valve positions, two gases with different compositions but the same Wobbe Index will give the same energy input to the combustion system. Thus, the greater the change in Wobbe Index, the greater the required flexibility of the combustion system and associated control. However, as shown in *Figure 8*, hydrogen has a much higher LHV per mass than natural gas, but its Wobbe Index is only slightly lower. This illustrates a limitation of using Wobbe Index for fuels containing hydrogen, which will require greater flexibility in the gas turbine combustion system and controls compared with natural gas, and the need for other methods of monitoring the gas fuel blend, such as direct gas composition measurement using gas chromatographs suitable for hydrogen.

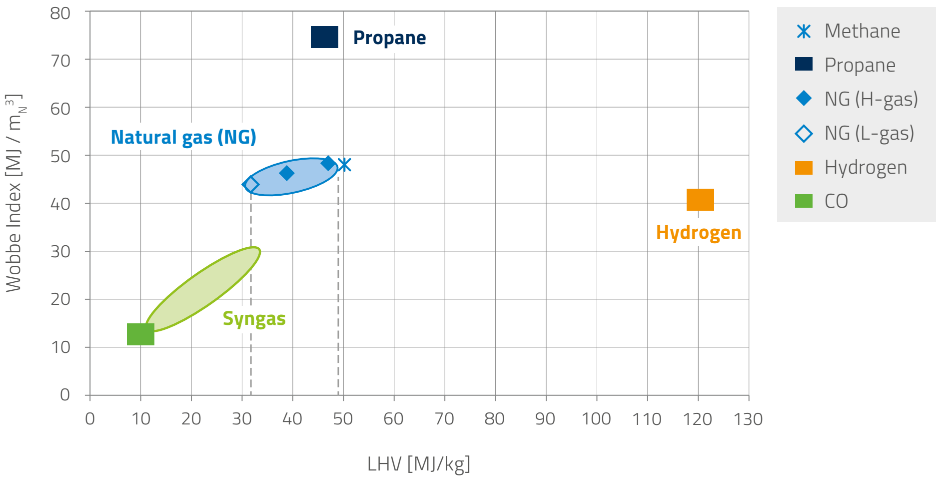


Figure 8 – Wobbe Index as a function of LHV for different fuels.

Impacts on hot gas path components

Burning hydrogen instead of natural gas will increase the moisture content in the exhaust gas. This can cause higher heat transfer to the gas turbine hot gas path components (e.g., turbine blades and vanes) and may require an adaptation of the cooling system to avoid overheating of components. In addition, due to the higher moisture content, hot corrosion may be more likely to occur, and the stability and life of thermal barrier coatings can be influenced. Since the water content in the exhaust gas depends mainly on the global fuel-to-air ratio and thus on the turbine inlet temperature, larger high efficiency gas turbines are likely to be more affected by this. For IGTs with turbine inlet temperatures in the range of 1200 °C, the increase in water content is on the order of few percent (by mass), and effects are expected to be less critical. Nevertheless, further research is needed to understand these effects in detail and the measures required to ensure the lifetime of the components.

4. Hydrogen integration into thermal power plants

4.1. Introduction

Hydrogen gas turbine design can leverage existing technology, avoiding the need for entirely new turbines. Most current gas turbines can be retrofitted to burn hydrogen with some modifications, mainly to the combustor and auxiliary parts (e.g., fuel supply system). Hydrogen gas turbine retrofit reduces capital costs and accelerates the energy transition.

Additionally, deploying hydrogen technology can extend the life of idle or underutilised gas turbines and even entire power plants, preserving jobs, saving resources, and benefiting society. This does not preclude deploying new dispatchable power generation equipment optimised for renewable fuels and a carbon-free electricity market.

In February 2022, the EU presented a new taxonomy [26] which applies from 1 January 2023 and sets certain carbon emissions thresholds for new thermal power plants to be considered as contributing to climate change mitigation. In this chapter, these thresholds are used as indicator of the volume of hydrogen required and what asset modifications are needed to achieve these thresholds for new-build and existing gas turbine assets. The thresholds are presented in the *Table 2*.

Table 2 – Thresholds of CO_2 emissions for sustainable activity according to the EU Taxonomy.

CO_2 emissions (gCO_2/kWh)	Remark
< 100	Sustainable limit. Any power plant operating below 100 gCO_2/kWh is consistent with the NZE pathway and is making a substantial contribution to the EU meeting its Paris Agreement commitments.
< 270	Do no significant harm limit: Power plants are considered doing no significant harm to the goals.
> 270	Significant harm limit. Any power plant operating above 270 gCO_2/kWh increases average EU emissions from current levels and risks harming the Paris Agreement.

Figure 9 shows the nominal CO_2 emissions of an IGT class and three heavy duty gas turbine classes operated with natural gas (for simplification, assumed here to be 100% methane). The CO_2 emission reduction between open cycle and combined cycle operation is obvious. But while realising the efficiency up to 64% of the latest H-class CCGTs, it is clear that the 270 gCO_2/kWh threshold is not reached. Blending a certain amount of low-carbon hydrogen with natural gas would make it possible to reduce CO_2 emissions below these limits.

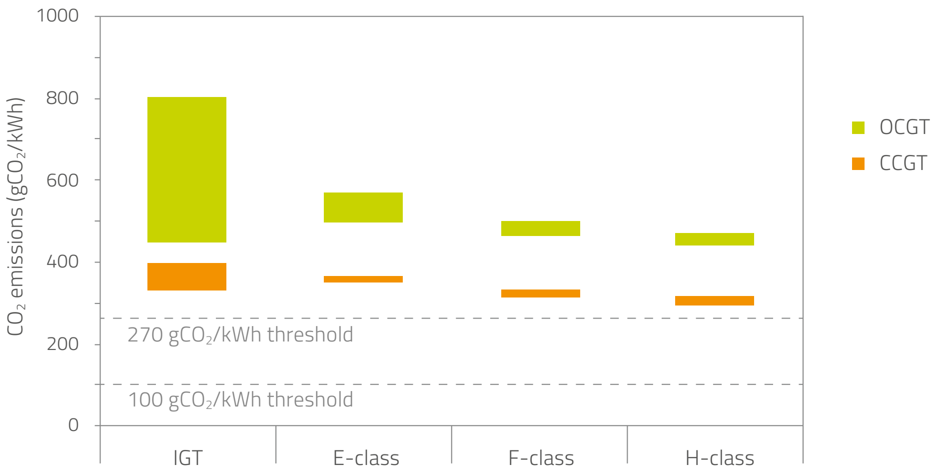


Figure 9 – CO_2 emissions (gCO_2/kWh) of example IGT and heavy duty gas turbines (data extracted from OEM websites and assuming methane combustion).

Figure 10a shows the CO_2 reduction for the different heavy duty gas turbine classes for CCGT power plants corresponding to the emission limits from the EU Taxonomy. The 270 gCO_2/kWh threshold results in a CO_2 reduction between 15% and 30%, while the 100 gCO_2/kWh threshold results in a CO_2 reduction of 70% compared with pure natural gas firing. The volumetric hydrogen blend with natural gas needed to reach the 270 gCO_2/kWh threshold is between 30-55% (*Figure 10b*), and the hydrogen consumption of such a power plant is between 3 and 6 tH_2/h (*Figure 10c*). To achieve the more stringent 100 gCO_2/kWh threshold, the volumetric hydrogen blend with natural gas is around 90%, and consumption ranges between 9 and 28 tH_2/h to produce up to 640 MWh of electricity.

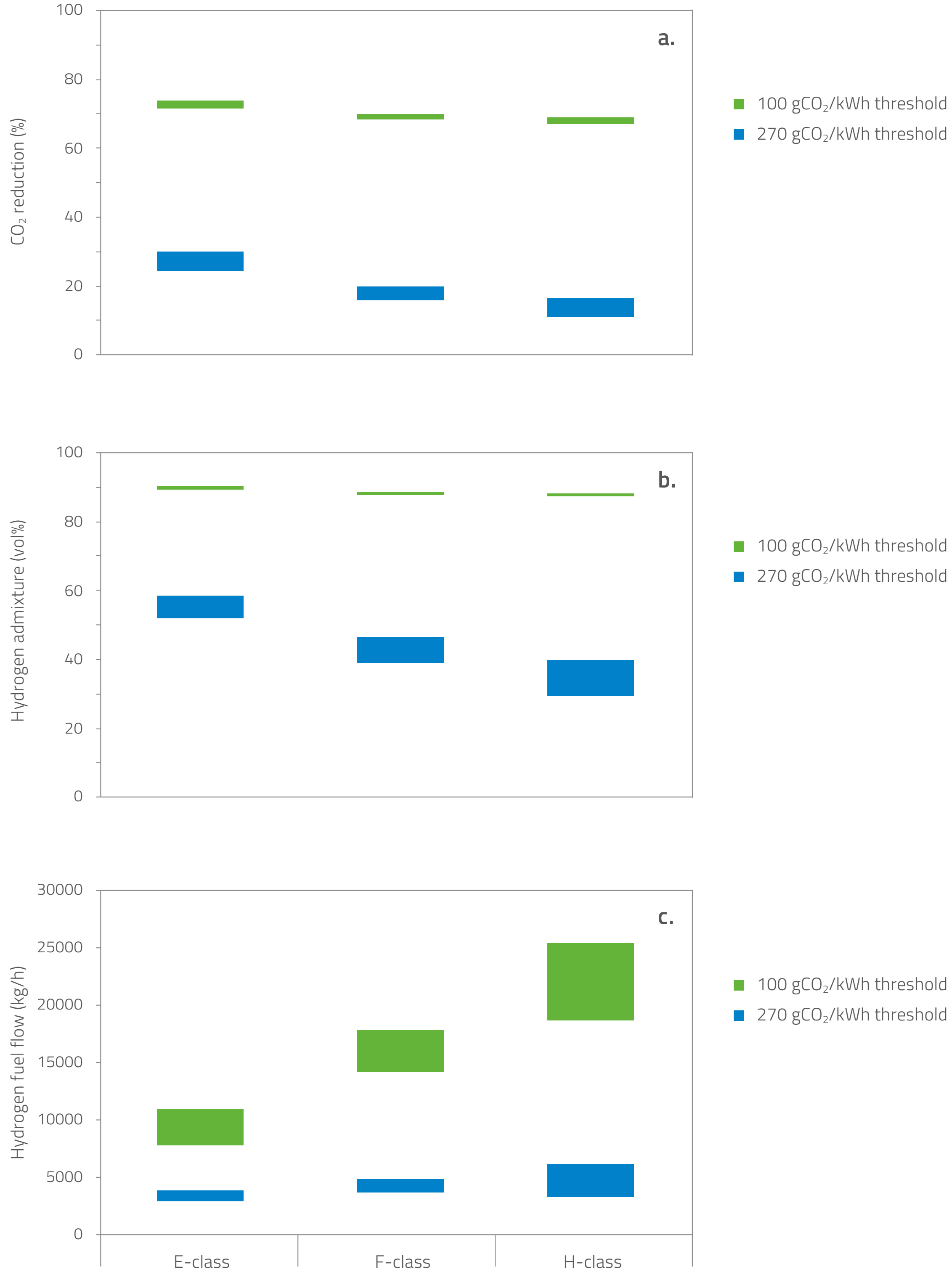


Figure 10 – CO_2 reduction (a), hydrogen volume content needed (b), and hydrogen fuel flow (c) with respect to different technology classes for 50 Hz CCGT plants.

4.2. New-build plants

Hydrogen is used on an industrial scale today in several applications, so the equipment and handling of hydrogen at an industrial site is state of the art. Thus, to build a power plant capable of using up to 100% hydrogen in a gas turbine should not be an unsolvable task. There are no references so far of such a new-build plant, and a first of a kind installation means a greater effort, but no unsolved challenges are to be expected. But while the political pressure on sustainable solutions for power and heat generation increases, and hydrogen is expected to play a significant role in energy storage, hydrogen supply is only available today in a few cases. Even as the first actions to build up a hydrogen supply are started (see Chapter 2), the infrastructure development will take many years. Furthermore, there is still uncertainty about how utilities can realise economic operation of such power plants. As a consequence of this situation, power plants built or projected today must run on fossil fuels (or blends with hydrogen) but might be operated with pure hydrogen during their lifetime. Indeed, many OEMs are preparing options for "hydrogen-ready" new-build gas turbine plants which can transition from natural gas to hydrogen operation over time. Even more, the possibility of switching to hydrogen fuel must already be proven today to demonstrate its sustainability. That is why the construction of such plants today needs to foresee the fuel change for the power plant, ideally at a minimum cost for the utilities, governments, and ultimately the electricity consumers. However, there are limited reference cases to evaluate the quality and completeness of such a power plant design, especially regarding additional fees, performance, and safety.

To overcome this gap, in 2023, TÜV SÜD in Germany developed a unified and OEM-independent evaluation framework for "hydrogen readiness of combined cycle power plants" [27] that allows for a standardised assessment of different providers and considers the whole power plant. While one intention of this certification is to document the sustainability to the authorities, it should also provide a first guideline for power plant builders and OEMs. This will increase transparency and build a basic framework of comparability for plant operators. TÜV issues certificates for different phases of the hydrogen conversion (e.g., concept, project, and transition certificate), which are voluntary so far. Such an approach offers an opportunity to close the gap between investment decisions and the availability of hydrogen and to drive forward the construction of new plants in parallel with the development of the infrastructure. It is to be expected that other certification bodies in Europe and worldwide will follow TÜV's approach in the future and develop similar approaches.

4.3. Existing plants

Retrofitting a gas turbine to burn hydrogen involves several technical and operational modifications to ensure safety, efficiency, and performance. Depending on the hydrogen blend, several modifications are required to ensure safe and reliable operation. Besides this, every unit has its own characteristics and should be evaluated on a case-by-case basis for integration of hydrogen combustion. At a minimum, the following retrofits or modifications need to be considered:

- Safety, ventilation, fire, and explosion
- Gas supply system
- Fuel mixing system
- Combustion system
- Flue gas system and heat recovery steam generator (HRSG)
- Instrumentation and control system

Table 3 shows today's generic consensus of modifications needed with respect to increasing hydrogen content used in a gas turbine power plant. The ranges in the table are indicative and assume that hydrogen is delivered to the plant in a separate pipeline and blended on site with natural gas. These listed required modifications may differ per plant, unit and design. In general, it can be assumed that smaller gas turbines with a lower efficiency are easier to modify, as there is greater margin available to the limits of the materials and components used. However, there may be specific reasons that make a conversion costly or even uneconomical. It is believed that today most existing gas turbines can operate with hydrogen blending up to 30% with existing DLE burner hardware and higher hydrogen contents in conventional, diffusion combustion systems. However, the exact amount allowable will also depend on the specific gas turbine type, combustion system, and plant layout. When considering hydrogen (co-)combustion in a power plant, an engineering study is highly recommended to determine the actual limits and any required modifications.

Table 3 – Required gas turbine plant modifications with respect to CO_2 reduction and hydrogen blend.

CO_2 reduction (%)	**≤ 5**	**≤ 11**	**≤ 31**	**≤ 100**
H_2 range (vol%)	≤ 15	≤ 30	≤ 60	≤ 100
Modifications	Minimal	Moderate	Considerable	Substantial
Safety				
ATEX equipment category	IIA	IIA/IIB	IIC	IIC
Detection and ventilation	Detection limits modification	Detection limits modification	Modifications needed	Modifications needed
Core engine				
Combustor	No changes	Modifications may be needed	Check H_2 compatibility	New design burner
Piping manifold	No changes	Modifications may be needed	Piping to be replaced	Piping to be replaced
Gaskets and valves	Modifications needed	Replacement needed	Replacement needed	Replacement needed
HGP	No changes	No changes	No changes	No changes
Fuel supply	Mixing skid	Mixing skid	Mixing skid	Mixing skid
I&C	Control system modifications	Control system modifications	Control system modifications	Control system modifications
HRSG	No changes	No changes	Impact on dew point, changes may be needed	Impact on dew point, changes are needed
SCR	No changes	No changes	May be needed	May be needed

In order to be complaint with the latest EU taxonomy, the modifications for hydrogen readiness fall in the "Considerable" level category, ≤60% H_2 (refer to *Table 3*). As today's existing burner technology (as currently installed in the majority of the installed capacity) will show increased NO_x emissions with the addition of hydrogen, measures are likely needed to meet the environmental regulations. These measures will likely impact gas turbine power and efficiency, such as installing a SCR unit, derating of the power output, or combustion dilution with water, steam, or nitrogen. In this situation, the CAPEX may be similar to the "Substantial" level category (≤ 100% hydrogen), while the CO_2 reduction benefits are far less. It is recognised that OEMs and third parties are developing and demonstrating new retrofittable, fuel flexible burners which are believed to be able to control NO_x emissions across the full range of hydrogen blends.

The techno-economic case study "Hydrogen Deployment in Centralised Power Generation" [28] by ETN's Young Engineers Committee presents an evaluation of the technical feasibility and economics of low-carbon hydrogen utilisation for large-scale gas turbine power generation. The main findings from the report are that the levelised cost of electricity (LCOE) for hydrogen gas turbines is expected to rise significantly due to high hydrogen prices, hydrogen blending in low-efficiency turbines is not economically competitive with natural gas because of additional costs, and current carbon prices are too low to justify switching from natural gas to hydrogen, with breakeven costs much higher than current EU carbon prices. However, because of the nonlinearity of volumetric hydrogen content and amount of CO_2 avoided (see *Figure 2*), higher hydrogen content in the fuel blend seemed to be beneficial with higher carbon prices.

4.3.1. Impact on operations

Research has shown that hydrogen gas turbine performance is similar for natural gas-fired units [29]. During the energy transition, fuel flexibility will be key for hydrogen-natural gas operation. The increased reactivity and higher flame speed of hydrogen require new combustion and fuel injection designs to be adopted for high-hydrogen fuelling. It is probable that at some point during the natural-gas-to-hydrogen transition, compromises will have to be made on emissions, power output, or power output ramp rates. Gas turbine part load operation or turn down will be improved due to the higher reactivity of hydrogen [30].

For transmission and distribution system operators, meeting power delivery requirements while maintaining specific voltage and frequency limits is becoming increasingly challenging. The growing integration of RES necessitates greater balancing efforts, prompting the energy industry to focus on solutions for flexible and dynamic operational performance. Power plant asset operators are putting greater emphasis on ancillary services. High ramp rates and flexibility in gas mixture content (based on availability of hydrogen) require fast-responding instrumentation and equipment (e.g., gas analyser, valves, etc.) that should be able to rapidly follow changes in fuel mixture.

4.3.2. Impact on downstream components and equipment

The impact of hydrogen utilisation on downstream components is mainly caused by changes in the exhaust gas composition, specifically by the increase of water content. While the flow rate and temperature of the exhaust gas does not change significantly with hydrogen firing compared with natural gas, the water content in the exhaust gas increases with increasing amount of hydrogen in the fuel and with decreasing global air to fuel ratio (see Chapter 3). Thus, the importance of the following points will vary with the specific model of gas turbine and plant layout (e.g., OCGT versus CCGT).

Turbine section and exhaust

It is likely that combustor exit temperature profiles at the turbine will be altered with the retrofit of a hydrogen-flexible combustion system. Whilst it is possible that temperature variations will decrease with micro-injector style (i.e., multi-point) fuel injectors, it is also almost inevitable that original hot gas path components will see different temperature profiles to those that they were originally designed for. The variations will potentially impact the component lifetime and therefore cannot be generalised. In addition to this, the increased water content in the flue gas will change the heat transfer to the components, leading to increased material temperatures that impact component lifetime.

Each retrofit solution should be qualified similar to a New Product Introduction, with appropriate qualification and risk management of key engine hot gas path components. A mix of validation by similarity, increased inspection, and analysis of ex-service components will be part of this qualification process.

If a diluent (e.g., water or steam) is required for NO_x control, this will typically reduce the maintenance interval for the hot gas path components or lead to gas turbine power output derating.

Heat recovery steam generator (HRSG)

Downstream of the gas turbine in combined cycle applications, the influence of hydrogen cofiring on the HRSG is minimal, but some mitigation measures may need to be considered.

The flue gas water content compared to natural gas will increase with increased hydrogen blends (roughly doubled at 100% hydrogen). At high-hydrogen blends, the recirculation system would need to be designed considering a higher Minimum Water Temperature (MWT) set temperature to prevent water condensation on the coldest HRSG tubes (i.e., the last stages).

The conversion of an existing natural gas-fired supplementary HRSG burner system (if applicable) into a hydrogen-ready system capable of accommodating various blends of natural gas and hydrogen presents several challenges. The design adaptations required to transition from a natural gas-fired supplementary burner system to a hydrogen-ready system must be carefully studied on a case-by-case basis to ensure optimal operation and performance of the system.

Selective catalytic reduction (SCR)

Hydrogen combustion in the gas turbine may result in higher NO_x concentrations in the exhaust gas due to the higher flame temperature of H_2, which favours NO_x formation (see Chapter 3). Depending on the local environmental requirements for NO_x control, SCR systems may already be installed for natural gas operation. The sizing of the SCR system in the HRSG is proportional to the NO_x content. Therefore, in preparation for a future hydrogen operation scenario, a larger spool duct needs to be considered for SCR expansion. However, in some existing CCGT applications, retrofitting or expansion of existing SCR systems may not be feasible due to space and cost limitations.

4.3.3. Hydrogen safety

Hydrogen safety in gas turbines is a critical aspect of advancing clean energy technologies. Hydrogen, while a promising low-carbon fuel, poses unique challenges due to its high flammability, wide range of ignition concentrations, and low ignition energy. Ensuring safe operation in gas turbines requires careful attention to leak detection, material compatibility, and flame control, and many of these techniques are in place today for natural gas operation. This section focuses on the gas turbine enclosure and equipment.

The gas turbine enclosure and the equipment enclosed must be considered from a safety perspective when adding hydrogen to the fuel, either as a blend or up to 100%. A gas leak in the gas turbine enclosure should always be avoided and all materials in gas service should be checked for hydrogen compatibility. This would typically include the fuel system such as pipes, valves, and fittings.

The key component for ensuring the safety of the enclosure is the ventilation. ISO 21789 should have been used for the design of existing enclosures for natural gas, but the standard is not intended for use with hydrogen. However, for blends up to 30% hydrogen, the mixture behaves similarly to natural gas and the standard could still be applicable. It is recommended that the enclosure ventilation is modelled with the intended blend as the gas composition and density will be different. Also, the gas turbine fuel pressure and flow may need to be increased to ensure the same energy delivery for combustion. These factors, besides the different gas properties, will affect the flow of a leak of a given size, and the enclosure flow should be re-modelled and compared with the initial design. The modelling may require different ventilation flow and positioning. In addition, the gas detectors may require repositioning. For blends up to 30% hydrogen, the same overpressure for the mechanical design of the enclosure should be considered.

For blends of between 25-30% hydrogen [31], the ATEX rating of electrical equipment and instrumentation changes. There is no consensus yet on the exact blend ratio, so a conservative approach is preferred. Nonetheless, a review of the suitability of all the instrumentation inside the enclosure should be performed as it is likely a significant amount of instrumentation will require changing. Additionally, as the blend increases and the ATEX zoning changes, surface temperatures will need to be considered, and this will also have an effect on the ventilation design.

At the time of writing, a gas turbine enclosure standard for 100% hydrogen does not exist, but investigations are underway to determine the suitability of the current standard. ETN Global is actively working on this topic through an industry-funded initiative to develop guidance for the gas turbine industry on hydrogen gas turbine enclosure safety. Preliminary opinion is that existing gas turbine enclosures are not suitable for 100% hydrogen, and new enclosures should be designed with specific applications in mind.

5. OEM achievements and ongoing developments

The entire value chain of the turbomachinery industry is currently prioritising the decarbonisation of gas turbines, in line with the climate neutral policies being implemented in Europe, North America, and eastern Asia.

Since the publication of the initial ETN Global Hydrogen Gas Turbines report [1] in January 2020, significant progress has been made in the development and demonstration of hydrogen gas turbine capability. Fundamental research in academia and research institutes has been translated into real-world deployment of gas turbines operating with advanced combustion systems on blends of hydrogen with natural gas up to 100% hydrogen. Further projects to install large-scale hydrogen-ready or hydrogen-blended gas turbines have been announced or are already under construction. *Figure 11* provides an overview of selected hydrogen gas turbine projects across the world, compiled from public sources.

Although this chapter does not represent an exhaustive inventory of all relevant activities, it provides a collection of current industrial initiatives and publicly funded projects aimed at enabling the global fleet of gas turbines to operate on 100% hydrogen. It also provides an impression of the current gas turbine OEM capabilities and developments for hydrogen operation. Sections 5.1 to 5.6 contain information provided by ETN Global's members. The final section (5.7) provides a brief snapshot of additional OEM activities in this rapidly developing area.

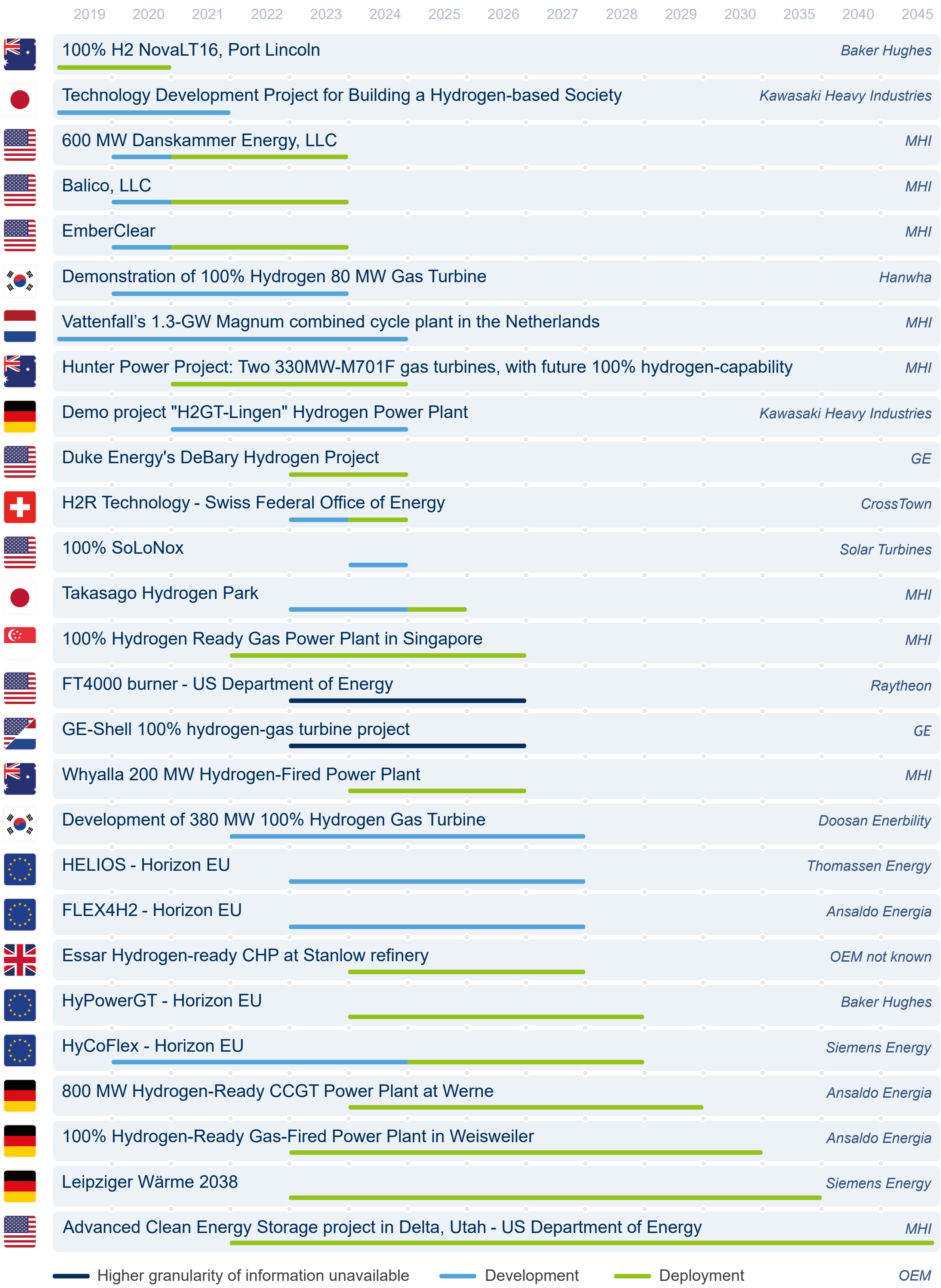


Figure 11 – Selected hydrogen gas turbine development and deployment projects listed by expected delivery timeline, country/region, and gas turbine OEM. Note each project includes a link for more details.

5.1. Ansaldo Energia

ansaldo energia

Ansaldo Energia is targeting to offer 100% hydrogen-capable gas turbines by 2030. The company has already delivered gas turbines with guaranteed 50% hydrogen capability. All Ansaldo engines are offered with up to 40% hydrogen capability. The GT26 and GT36 gas turbines are offered nowadays with up to 45% and 70% hydrogen capability, respectively. This section reports a list of selected projects where Ansaldo is developing solutions for operation with up to 100% hydrogen.

FLEX4H2 (Flexibility for Hydrogen) Project

The FLEX4H2 project [32] is developing and validating an efficient and fuel-flexible combustion system capable of operating with any natural gas-hydrogen blend (including 100% hydrogen), without the use of diluents. This objective is pursued at the most challenging hydrogen combustion conditions (i.e., at H-Class operating temperatures), required for highest cycle efficiency, while still meeting emissions targets. The design of the combustor is based on Ansaldo Energia's Constant Pressure Sequential Combustion (CPSC) technology and will be demonstrated at full gas turbine operating conditions (TRL6). The improved combustor design will be fully retrofittable to existing gas turbines, providing significant opportunities for refurbishing existing assets. The project is supported by the Clean Hydrogen Partnership and its members Hydrogen Europe and Hydrogen Europe Research (GA 101101427), and the Swiss Federal Department of Economic Affairs, Education and Research, State Secretariat for Education, Research and Innovation (SERI).

Within this project, in October 2023, a GT36 sequential combustor prototype was tested in a rig at high-pressure conditions. The combustor was successfully operated with natural gas, pure hydrogen (derated), and the full range of blends in between (see *Figure 12*).

Project on micro gas turbines

Regarding the microturbine AE-T100, several European development activities are currently focused on enhancing the hydrogen burning capabilities of the combustion system. The goal is to enable the system to operate either on a blend of natural gas and hydrogen or on 100% hydrogen, depending on application requirements. For example, in Germany, the development is driven by Power Service Consulting GmbH (PSC) and the German Aerospace Centre (DLR). The first AE-T100 micro gas turbine was operated in May 2022 on pure hydrogen fuel by the University of Stavanger (UiS), Norway, using a new jet-stabilised combustion system developed by DLR and manufactured by PSC.

In February 2024, an AE-T100 was operated with up to 50% hydrogen blend with natural gas during a test campaign by the University of Sheffield (UK). The gas turbine installed at their research facilities was modified in a collaboration between PSC and Ansaldo Green Tech and aimed to achieve high flexibility with hydrogen in blends with natural gas.

In June 2024, the performance of the new combustion system was further demonstrated at the DLR research facility site at Lampoldshausen, reaching stable operation during tests with 100% hydrogen in an AE-T100 unit modified by PSC.

In the summer of 2024, a pure hydrogen AE-T100 microturbine was also commissioned at the University of Ulm (Germany).

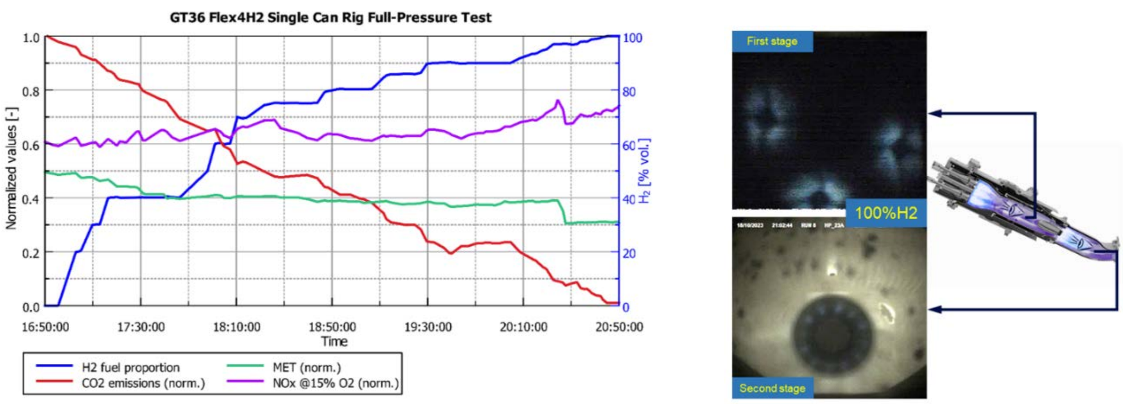


Figure 12 – Test of the GT36 hydrogen-optimised combustor from 0 to 100% H_2 in natural gas, key test parameters (left) and flames image at 100% hydrogen (right). More info at www.flex4h2.eu.

5.2. Siemens Energy

Siemens Energy gas turbines are available for oil and gas applications, industrial heat and power generation, and power production ranging up to 593 MW (open cycle).

New Siemens Energy gas turbines are available with different levels of hydrogen blending capability, depending on the type:

- Aeroderivative gas turbines up to 100% H_2 in diffusion combustion mode with NO_x abatement using water injection. With DLE technology, up to 15% hydrogen is possible for the SGT-A65 and SGT-A35 gas turbines.
- Large-scale, utility gas turbines with up to 30% hydrogen blending in DLE technology.
- Medium-size industrial gas turbines (i.e., SGT-600 to SGT-800) with blends of up to 75% H_2 in DLE technology.
- Small industrial turbines (i.e., SGT-100 and SGT-300) with up to 30% vol in DLE technology. Using diffusion combustion technology with unabated NO_x will increase the allowable blending capability up to 65% hydrogen.
- Small industrial turbine – SGT-400. 100% hydrogen capability was demonstrated on this gas turbine in summer 2023 using a newly developed combustion system (see *Figure 13*) and demonstrating low-NO_x capability across a range of high-hydrogen blend ratios (see *Figure 14*).

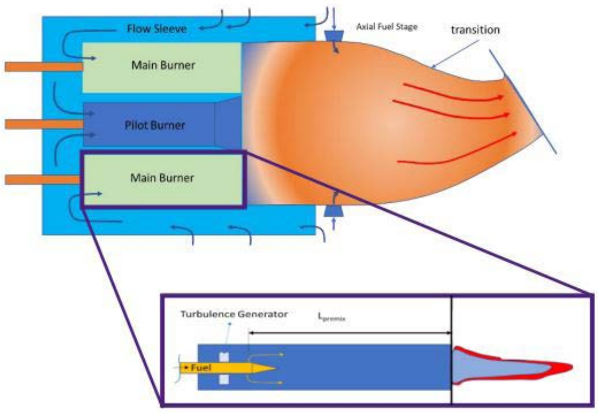


Figure 13 – Advanced combustion technology with jet-based burner and axial staging [24].

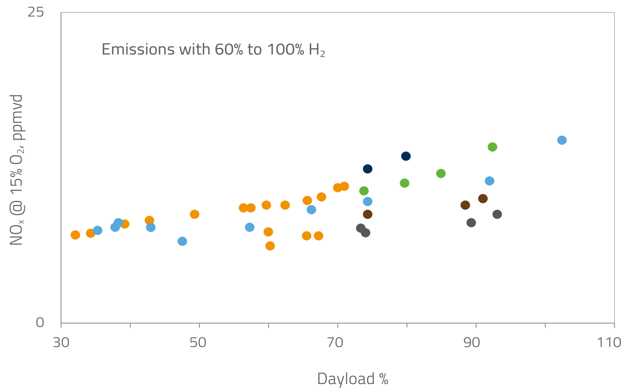


Figure 14 – SGT-400 NO_x emissions from 60% to 100% hydrogen in natural gas [24].

The specific capability of blending hydrogen in an existing gas turbine always needs to be checked for each site individually, as the specific installed hardware and plant setup might differ based on age and local conditions. To reach the same abovementioned values as for new apparatus, upgrades to the control system and hardware might be needed and are available for many GT types.

For example, for Siemens Energy 2000E and 4000F gas turbines, the standard upgrade package "H_2DeCarb" for higher hydrogen contents is available. The 2000E gas turbine upgraded with the "H_2DeCarb" package can operate with up to 30% hydrogen. For the 4000F gas turbine, an upgrade enabling operation up to 15% hydrogen is possible.

The standard capability for IGTs reaches up to 10% hydrogen in existing packages, depending on the actual package generation design, and up to 15% hydrogen as standard for new units. On existing sites, an analysis needs to be conducted to assess the need for component exchange to allow higher shares of hydrogen in the fuel. Today's IGTs with third-generation DLE system (standard for all delivered SGT-700 and SGT-800 gas turbines and optional for the SGT-600) have high capabilities to burn hydrogen, with levels up to 50 – 75% hydrogen. Aeroderivative gas turbines, equipped with Wet Low Emissions (WLE) systems can achieve high hydrogen blending capabilities. However, similar site assessments by Siemens Energy should always be conducted to clarify if service overhaul times would be affected by higher hydrogen concentrations than already guaranteed.

5.3. Solar Turbines

Solar Turbines' experience in operating gas turbines with significant hydrogen fuel gas concentrations spans 40 years. With the growing demand for hydrogen blends and low NO_x emissions, Solar has demonstrated, through long-duration trials, the capabilities of its existing SoLoNO$_x$ dry low emission products to operate on hydrogen blends as high as 60%. Solar Turbines is advancing a platform capable of burning blends of natural gas and hydrogen ranging from 0 to 100% with emissions comparable to natural gas and engine test capabilities by the end of the decade.

Solar Turbines' hydrogen experience spans 55 gas turbines sold, amassing over 2 million operating hours on hydrogen-rich blends up to 65%. *Figure 15* shows four Titan 130 hydrogen-capable gas turbines installed at Shanxi Liheng Steel Co. in China [33]. Many of these units have undergone multiple overhaul cycles with proven durability, and Solar currently offers 100% hydrogen-ready units with standard (diffusion) combustion. SoLoNO$_x$ units have successfully operated on hydrogen blends for over 20 years in refinery and petrochemical applications. Today, units with 20% hydrogen capabilities are commonly sold for power generation and gas transmission applications. Earlier generations of SoLoNO$_x$ combustion systems can also be upgraded to utilise high-hydrogen blends.

Figure 15 – Titan 130 conventional combustion gas turbine packages operating with up to 65% hydrogen [33].

The current SoLoNO$_x$ products feature robust hydrogen capabilities. Recent long-duration demonstrations have showcased this, including a Titan 130 compressor set (shown in *Figure 16*) operating in Germany for over 200 hours with up to 25% hydrogen in a gas transmission application, achieving full power and emissions below site guarantee levels [34].

In 2024, a Centaur 40S gas turbine demonstration in the USA has already logged over 400 hours of operation with hydrogen blends up to 60%, further illustrating the wide fuel range capabilities of the SoLoNO$_x$ combustion platform. This high hydrogen test will continue for several months with engine emissions and performance comparable to natural gas [35].

Figure 16 – Titan 130 SoLoNO$_x$ hydrogen demonstration in Germany with full injector instrumentation.

Beyond validating the high hydrogen operation of the existing SoLoNOx platform, Solar Turbines is committed to developing a new combustion platform capable of operating on hydrogen blends from 0% to 100% with natural gas. This platform aims to achieve NO_x emissions similar to natural gas operation. Early developments have shown promising results, and 100% hydrogen engine testing capabilities will soon be available at the Hydrogen Hub Test Center in Texas.

5.4. Baker Hughes

Baker Hughes is an energy technology company that has a diverse portfolio of equipment and service capabilities that span the energy and industrial value chain. Formed in 2017 by the integration of General Electric Oil & Gas business and former Baker Hughes company, the company retains a wide and deep expertise in the field of gas turbines, leveraging decades of knowledge sharing and cooperation with GE entities for heavy duty and aeroderivative gas turbines. NovaLT™ is a proprietary light industrial GT family designed to target the power range up to 20 MW with high efficiency, availability, flexibility and low cost of ownership.

The maximum allowable hydrogen concentration in lean premixed combustors varies significantly across the Baker Hughes gas turbine fleet, as different combustion technologies are employed. Fuels with significant hydrogen content are carefully evaluated, and their potential to be used is assessed case-by-case considering the peculiarities of each project. Standard and Lean Head End combustors (for heavy duty gas turbines) or Single Annular Combustors (SAC, for aeroderivative gas turbines) have been tested and employed in the past to burn very high hydrogen concentrations, with diluent injection for NO_x emission abatement. As far as the application of lean premixed combustors is concerned, capabilities are consistent with limits specified for DLE and DLN1/DLN2 combustors as reported in the section devoted to GE Vernova (see section 5.7.1).

Regarding the NovaLT™ gas turbine family (see NovaLT™16 in *Figure 17* and *Figure 18*), the engines are equipped with piloted premixed burners arranged in annular combustors, capable of modulating the fuel split between pilot and premix lines along the operating range and based on fuel composition. This flexibility allows the engines to burn up to 100% hydrogen, with variable fuel gas mixtures, with and without diluent injection, and with consequently variable NO_x emission levels [36] [37] [38] [39].

To cope with the challenges of hydrogen combustion, Baker Hughes is investing in the development of technologies mainly dealing with design criteria and simulation tools for hydrogen flashback and deflagration/detonation, prototype burner testing at full operative pressure, and materials characterisation in hydrogen environments. Such technologies are applied on the NovaLT™ product line and especially on the NovaLT™16 gas turbine, the front runner.

In the first quarter of 2024, Baker Hughes successfully completed the engine test campaign of the first NovaLT™16 hydrogen unit, demonstrating the capability of the engine to burn any blend of natural gas and hydrogen up to pure hydrogen. This also ncludes the ability of the gas turbine to start-up on pure hydrogen and the possibility to switch the loads "on the fly" (i.e., without stopping the engine). Tested conditions included the fast switch from natural gas to hydrogen and vice versa and the reliability of the control logics over the worst transient events, such as incremental load steps up to a full load rejection condition.

The combustor configuration equipped on the NovaLT™16 hydrogen unit is based on a partial premixing technology, able to guarantee NO_x emission within 15 ppm normative limit, by means of a commercially available SCR at the exhaust. While such GT configuration is already available on the market, the hydrogen DLE combustor based on a full premixing technology is under development to target the same NO_x emission limit without the need for the SCR at the exhaust.

The results already achieved with the hydrogen DLE technology on dedicated full pressure tests have been instrumental to building a consortium with renowned partners for the European-funded project HyPowerGT [40]. The HyPowerGT project started in January 2024 and is targeting TRL7 for a hydrogen DLE gas turbine.

Figure 17 – NovaLT™16 100% hydrogen-ready gas turbine, installed on the Baker Hughes test bench at its Florence site (IT). Image courtesy of Baker Hughes.*

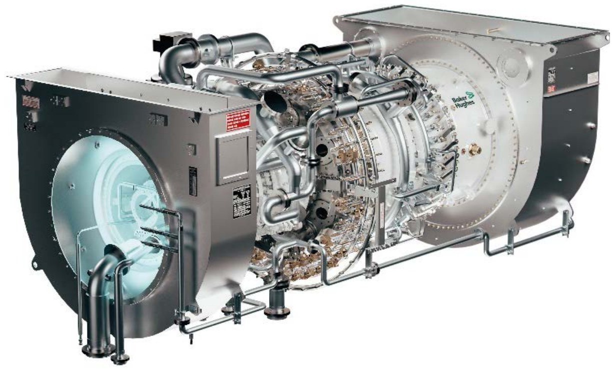


Figure 18 – Baker Hughes NovaLT™16 gas turbine, 100% hydrogen-ready. Image courtesy of Baker Hughes.*

5.5. PSM and Thomassen Energy

Clean Energy Solutions for Future Generations

PSM and Thomassen Energy, sister companies owned by South Korea-headquartered Hanwha Group, are the world's leading full-scope aftermarket multi-OEM gas turbine service providers. Either transactionally or via flexible long-term service agreements, PSM and Thomassen Energy offer their own innovative technology retrofit offerings to power generation operators that signficantly improve and enhance the performance, operational flexibility, fuel flexibility, and maintenance life cycle costs for select installed fleets of B, E and F-class gas turbines originally manufactured by GE Vernova, Siemens Energy, and Mitsubishi Power. PSM and Thomassen offer two combustion system retrofit platforms, the FlameSheet™ (see *Figure 19* and *Figure 20*) and LEC-III™ combustors, not only designed to operate with improved operational range and ultra-low NO_x emissions, but also operate with a variable blend of natural gas and clean hydrogen up to 100% depending on the turbine type.

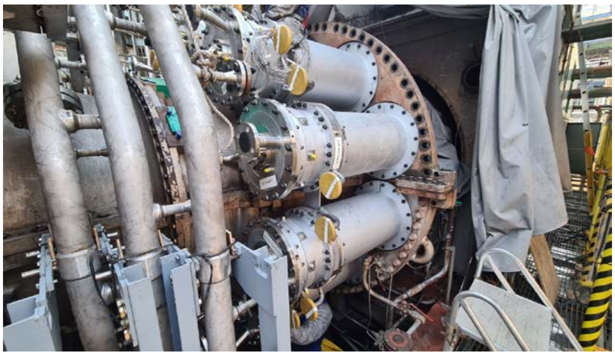


Figure 19 – Typical FlameSheet™ combustor installation.

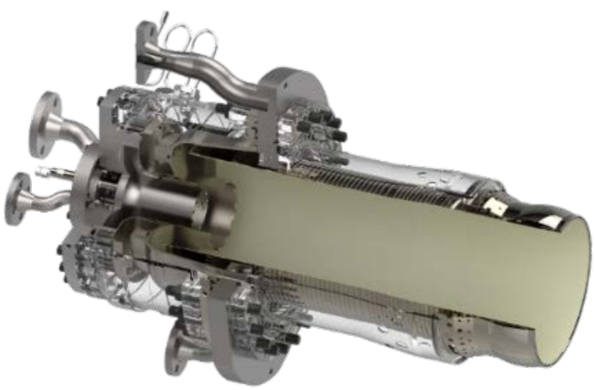


Figure 20 – FlameSheet™ combustor.

The FlameSheet™ combustor platform, a revolutionaly retrofit solution concieved in 2003 and in commercial operation since 2015, is installed on 26 gas turbines globally (as of July 2024), accumulating over 300,000 operating hours in four different gas turbines: the GE Vernova Frame 5PA, 7E, and 7F and Siemens Energy 501FD2. The FlameSheet™ was tested successfully in a Frame 7EA in 2023 in Daesan, South Korea at up to 60% hydrogen at base load operating conditions (a world record, limited only by the maximum availability of hydrogen) and then at 100% hydrogen at Full Speed No Load (FSNL), both with single digit (ppm) NO_x emissions. A 7F FlameSheet™ is commercially operating in the US since 2023 with upwards of 25% hydrogen from available refinery off gas. The FlameSheet™ for the Frame 5P and 6B are both commercially available for order today for up to 100% hydrogen (as shown in *Figure 21*). The Frame 7E/7F/9E/9F gas turbines are available for up to 80% hydrogen today with current development plans to quickly extend this up to 100% hydrogen in a staged approach based on desired customer application requirements.

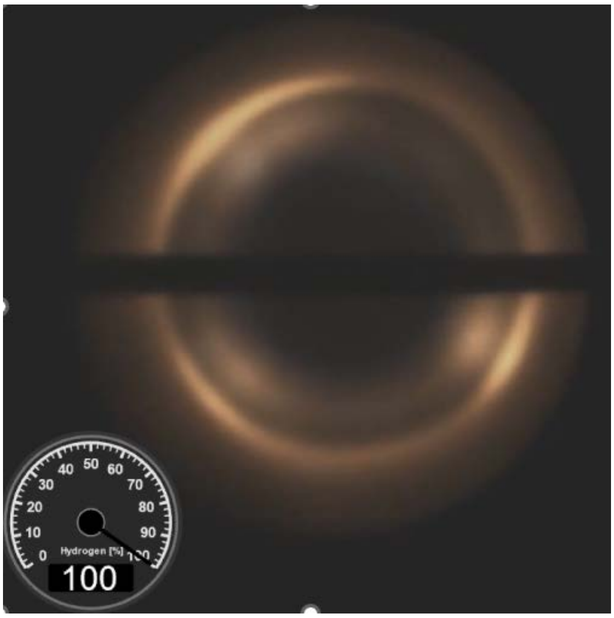


Figure 21 – FlameSheet™ combustor operating at 100% H_2.

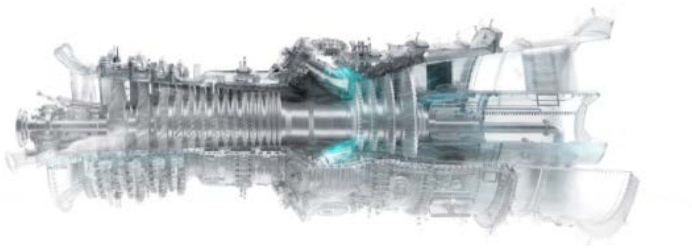
5.6. Mitsubishi Power

Hydrogen gas turbine initiatives for carbon neutrality

Mitsubishi Power's hydrogen firing technology enables power plant owners to decarbonise their existing CCGT plants by converting them to hydrogen co-firing, or even 100% hydrogen firing. With a minimum of modification, Mitsubishi Power supports the transition process by identifying key preparatory and operational steps necessary to decarbonise generation plants while working with customers to create a roadmap for reducing CO_2 emissions. Therefore, the development of gas turbine combustor and combustion technology is the key to success in developing a hydrogen gas turbine.

Mitsubishi Power has developed three types of combustor technologies to support the development of hydrogen-ready gas turbines. The table shown in *Figure 22* shows the status of the three combustion types used in hydrogen-ready gas turbines: Diffusion, Premix and Multi-cluster [41].

As Mitsubishi Power has successfully achieved mixed-combustion power generation at 30% hydrogen, the next objective is CO_2-free power generation or 100% hydrogen power generation technology. However, with a high concentration of hydrogen, the risk of flashback rises, as does the concentration of NO_x. A combustor for hydrogen-fired power generation demands technology that enables stable combustion and efficient mixing of hydrogen and air. There are important conditions concerning the mixing of hydrogen and air as well. Hydrogen is an excellent fuel, but can be difficult to handle. Engineers are approaching this development challenge by changing their thinking about fuel-air mixing methods, such as by upgrading the injection nozzles.



Takasago Hydrogen Park

Comprehensive technical verification of hydrogen production, storage, and power generation

The Takasago Hydrogen Park is located at Mitsubishi Power's Takasago Machinery Works in Japan. It is the world's first center for the validation of hydrogen-related technologies from production and storage to utilisation for power generation [42]. The H-25 gas turbine, a 100% hydrogen-fired 30-40 MW class gas turbine, will undergo validation testing here to reduce the risks associated with hydrogen combustion. Hydrogen blending and operation up to 30% will also be validated in a large-scale 450 MW class J-series, air-cooled (JAC) gas turbine. The validation will also include the intelligent solution suite TOMONI®.

Advanced Clean Energy Storage (ACES) Project, Delta, Utah

Using a Mitsubishi Power validated gas turbine coupled with salt cavern hydrogen storage, the 840 MW CCGT plant will run on a blend of 30% green hydrogen and 70% natural gas starting in 2025, incrementally expanding to 100% green hydrogen by 2045 [43]. The project renews a major coal-fired power plant – a unique example of bringing clean hydrogen at scale to replace fossil fuels.

Hydrogen Gas Turbine Combustor Development Status

	Combustion method	Low NO_x technology	Performance	Hydrogen Content	Development/operation status
Type 1	Diffusion Combustion	N_2 Dilution Water/Steam Addition	Combustion Temperature 1200°C - 1400°C Class	100%	Development completed
Type 2	Premixed Combustion	Dry Low NO_x	Combustion Temperature 1650°C Class	30%	Development completed
				50%	Successful combustion test in 2022
Type 3	Multi-Cluster	Dry Low NO_x	Combustion Temperature 1650°C Class	100%	Development scheduled to be completed after 2025

Figure 22 – Mitsubishi Power hydrogen gas turbine combustion technology [41].

5.7. Additional gas turbine OEMs and service providers

In addition to the ETN Global Member OEMs presented in this chapter, it is acknowledged that other gas turbine OEMs and service providers are actively developing hydrogen gas turbines. The following snapshots from publicly available information highlight the breadth of hydrogen experience across the gas turbine industry.

5.7.1. GE Vernova

GE Vernova (United States) has 50+ years of experience operating over 120 gas turbines and over 8.5 million hours on fuels with hydrogen content from 5% up to 100% [44]. New GE Vernova gas turbines cover the full range of sizes from aeroderivatives to H-class, with a variety of combustion technologies and hydrogen capabilities, as shown in *Figure 23*, which is plotted against volumetric hydrogen content in a blend with natural gas (current as of February 2022) [45]. GE Vernova is also developing a dry low-NO_x combustor called the DLN Evo which will be capable of operating with high hydrogen blends and retrofittable for its F-class gas turbines [46].

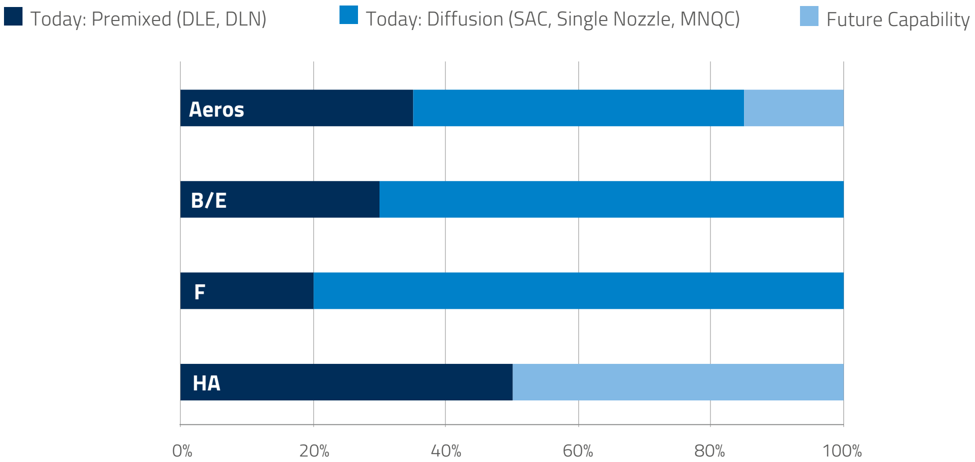


Figure 23 – GE Vernova new gas turbine hydrogen capability by gas turbine type, combustion system, and hydrogen blend [45].

5.7.2. Kawasaki Heavy Industries

Kawasaki Heavy Industries (Japan) is contributing to CO_2 reduction by supporting the fuel conversion from natural gas to hydrogen in distributed power generation and CHP systems across its range of gas turbines with power outputs from 1.7 MW to 30 MW in open cycle [47]. Today, Kawasaki's DLE combustor is capable of operating with up to 30% hydrogen blending and its diffusion combustor can operate with blends from 0% to 100% hydrogen. In 2023, Kawasaki also commercialised a 1.8 MW gas turbine cogeneration system (GBP17MMX) capable of operating with 100% hydrogen in a dry, micro-mix combustion system [48], shown in *Figure 24*. It is expected that this micro-mix combustion system will be scaled to operate in the larger gas turbines in the Kawasaki range by 2030.

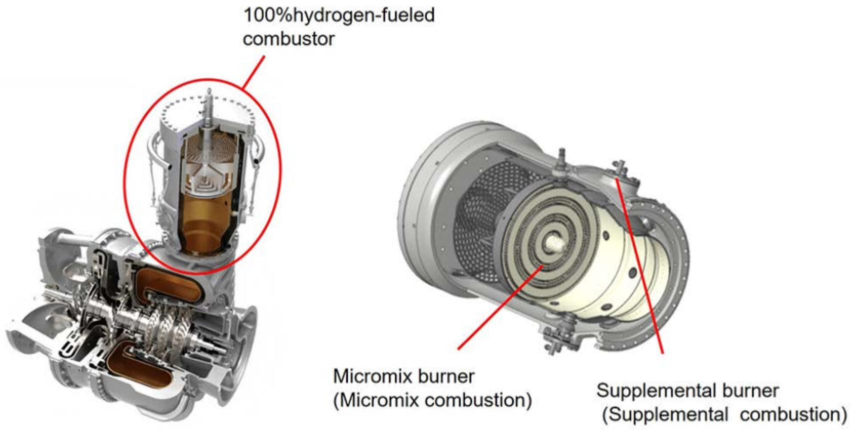


Figure 24 – Kawasaki GPB17MMX cogeneration gas turbine (left) and micro-mix combustion system (right) [48].

5.7.3. Doosan Enerbility

Doosan Enerbility (South Korea) is a gas turbine OEM with a range of gas turbines from 5 MW to 380 MW (H-class) open cycle output. In August 2022, Doosan successfully completed testing of 30% hydrogen blending in its 300 MW gas turbine [49]. In 2023, Doosan signed an MoU with 12 organisations in South Korea to develop and demonstrate its H-class gas turbine operating with up to 50% hydrogen blending by 2027 [50]. Doosan Enerbility also has the goal to complete development of its H-class gas turbine capable of 100% hydrogen firing by 2027, with development of the hydrogen combustor by 2026 [49].

5.7.4. Crosstown Power

Crosstown Power (Switzerland) is a gas turbine service provider that has developed the "H2R® burner", a 100% hydrogen-capable retrofit combustion system for gas turbines [51]. The H2R® burner is intended to operate with 100% natural gas, 100% hydrogen, and blends in any proportion. The burner is scalable to multiple gas turbine frame types and has been demonstrated in a high-pressure test rig to operate at full engine conditions in a DLE configuration with NO_x emissions below 15 ppmvd. Full engine trials of the H2R® burner in a 15 MW gas turbine (*Figure 25*) are expected in the second half of 2024 [52].

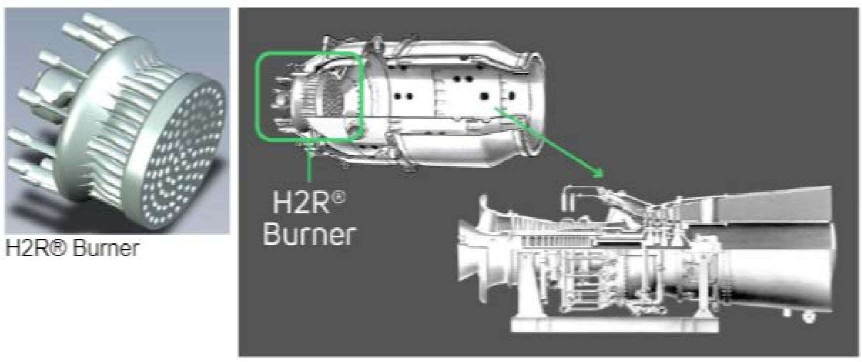


Figure 25 – Crosstown Power H2R® burner adapted for a 15 MW gas turbine [52].

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