AFRY
ÅF PÖYRY

White Paper

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1 BACKGROUND

With the EU climate targets set for 2050, clean and flexible – instead of only efficient – power generation will drive the agenda of gas turbine development in the future. Hydrogen as gas turbine fuel is one of the alluring options since it does not produce indirect and direct CO_2 emissions when produced as green and burned as pure hydrogen. In the context of this note, green hydrogen is the denomination used for hydrogen produced by entirely renewable energy sources.

Hydrogen and energy have a long-shared history – powering the first internal combustion engines over 200 years ago to become an integral part of the modern refining industry. Though hydrogen can be extracted from biomass (by gasification) or from water by means of electrolysis, natural gas steam reforming is currently the primary source of hydrogen production, accounting for around 75% of the annual global dedicated hydrogen production of around 70 million tonnes today. As of today, less than 0.1% of global dedicated hydrogen production comes from water electrolysis /1/.

Yet the steam reforming process for producing hydrogen, in which natural gas with a high methane content is exposed to steam, is not an environmentally friendly process due to the release of a substantial amount of CO_2 emissions. Hydrogen produced using steam reforming is called grey hydrogen; if the CO_2 generated during the steam reforming process is captured and sequestered, it is called blue hydrogen.

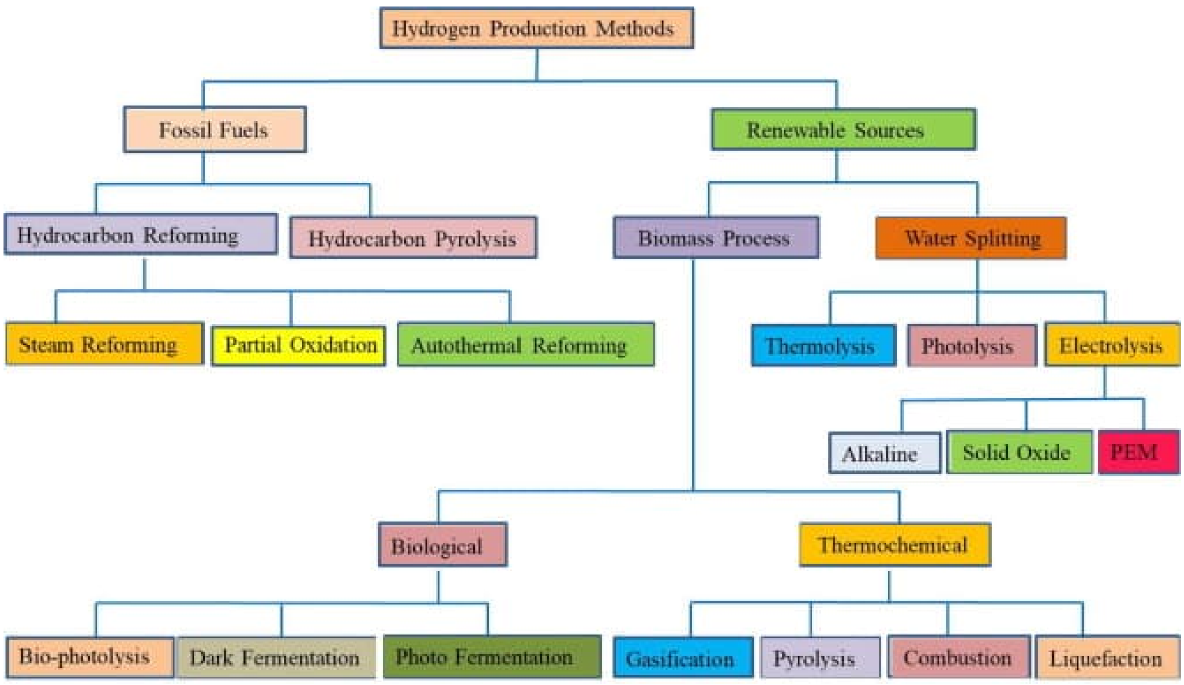


Figure 1: Hydrogen production methods.

Green hydrogen is *different* in the sense that it is entirely produced by using renewable energy sources. In its most common form, green hydrogen is produced through water electrolysis, a process which splits water into hydrogen (H_2) and oxygen (O_2) by passing a high electrical current through an electrolyte (typically an alkaline solution of KoH) with no emissions and only O_2 as by-product. Historically, and due to the high electrical potential needed to split the water molecule, and available materials efficiency, electrolysis requires a high amount of electricity, thus costs, to produce hydrogen. In the future, this situation could be different for two reasons:

1. Availability of large amounts of (localized) excess renewable electricity at grid scale, and
2. Electrolysers having the potential to become more efficient.

For green hydrogen to make a significant impact to the clean energy transition, it needs to be adopted in sectors where hydrogen is likely to be the only option. Renewable technologies such as solar and wind (in combination with storage) could largely decarbonize the energy sector by replacing fossil fuels with clean electricity. Other parts of the economy, such as mobility and manufacturing processes, are harder to electrify because they often require fuel that is high in energy density or heat at high temperatures.

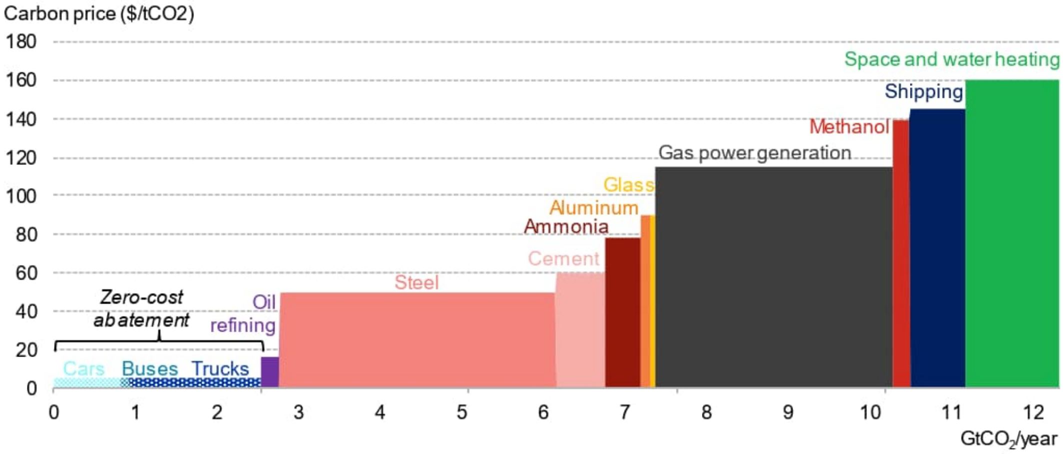


Figure 2: Marginal abatement cost curve from using $1/kg hydrogen for emission reductions, by sector in 2050 /13/.

Studies published by Bloomberg /13/ and Goldman Sachs /15/ shows that the strongest use cases for hydrogen are those with direct use in manufacturing processes (cement, steel).

The power generation sector will likely be a hard-to-abate since the costs for producing hydrogen, compared to fossil fuels are higher, though this argument may change in the future. In this context it is more important to realize that due its physical properties hydrogen has some technical drawbacks over other gaseous and liquid fuels that make other alternative technologies more attractive for large scale power generation.

Despite green hydrogen may have most potential to be used directly in the industry, there may be cases where green hydrogen as gas turbine fuel could make sense, e.g. clusters with the availability of large-scale renewable power generation, water and existing infrastructure in combination consumers having a high power demand.

This paper presents the outcomes, based on discussions with gas turbine Original Equipment Manufacturers (OEM), service companies and public sources, about using hydrogen as gas turbine fuel.

The GT OEMs who have supported AFRY, by sharing information on their new-build gas turbine hydrogen burning capabilities, were:

- Ansaldo Energia
- Siemens Energy
- General Electric (GE)
- Mitsubishi Hitachi Power Systems (MHPS)

Thomassen Energy contributed to providing information about retrofitting existing gas turbines.

2 HYDROGEN AS GAS TURBINE FUEL

2.1 Why Hydrogen?

Hydrogen is a clean burning fuel that does not produce any CO_2 emissions as it does not contain any carbon. In a balanced complete combustion reaction, the only combustion product is water. Figure 3 shows the relationship between the CO_2 emissions and hydrogen/methane fuel blends (volume %). As shown, this relationship is non-linear. The gas turbine requires a constant heat input and since hydrogen has a lower volumetric energy density, a blend on a heat input basis contains less hydrogen (relative to a blend on a volumetric basis). This is the reason that a substantial amount of methane needs to be substituted by hydrogen (>50%) to have a significant impact on reducing the CO_2 emissions. E.g. at 50% hydrogen vol. content 24% of the heat content is coming from hydrogen, thus approximately 20% reduction in CO_2 emissions.

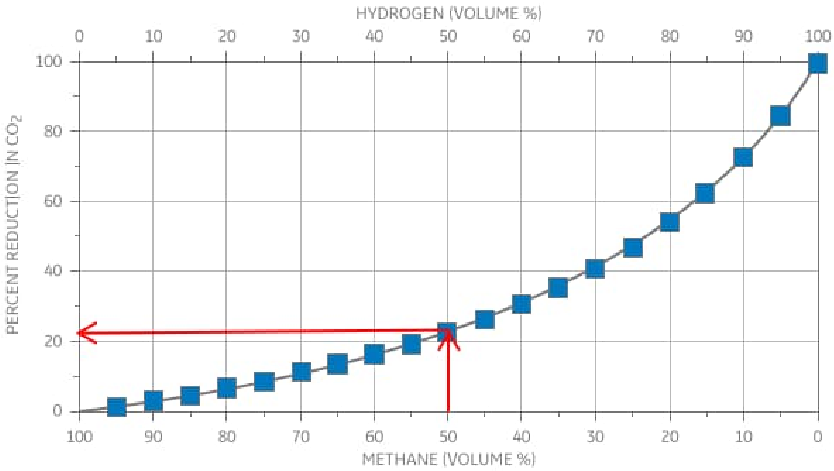


Figure 3: Relationship between CO_2 emissions and hydrogen/methane fuel blends (volume %). /12/.

2.2 Impact of Hydrogen as Fuel

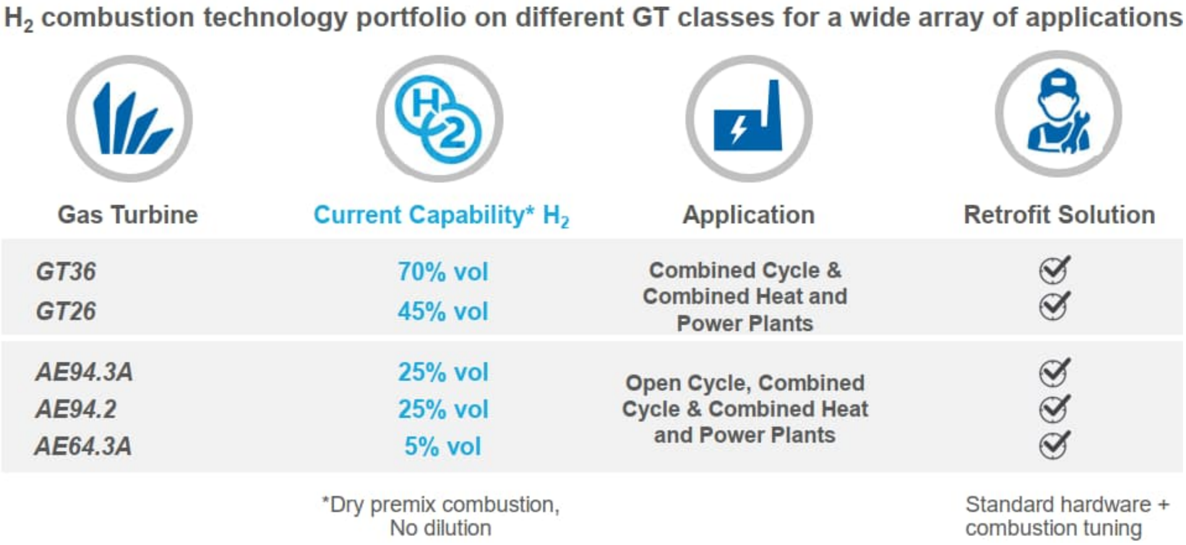
Though it would be very alluring to use hydrogen as gas turbine fuel, its combustion on a gas turbine has certain implications from which the most important ones are:

1. On volumetric basis hydrogen is one third less energy dense than methane. Therefore, it takes three times more volume flow of hydrogen to provide the same heat (energy) input as methane. To handle these larger volume flows, systems need to be designed for it. This can create an issue on fuel gas systems of existing plants that intend to convert their GTs to hydrogen.
2. Hydrogen's high reactivity:
    a. Burning hydrogen results in higher adiabatic flame temperatures, thus an increase of localized NO_x production. To stay within the NO_x limits de-rating or wet combustion will be necessary at higher hydrogen volume contents. As per today, most gas turbines can handle fuels mixtures up to 25-30% hydrogen volume without any or very little design change and/or operational restrictions (de-rating or wet combustion to abate NO_x emissions).
    b. Hydrogen's higher flame speed makes the flame front to move upstream into the pre-mixing zone, thus closer to the burner. This increases the risk of so-called flashback.
3. Hydrogen as fuel for large heavy duty gas turbines requires a large amount of power and water to produce it (see examples hereafter).
4. Hydrogen is a hazardous gas and requires more safety measures in designing and operating the systems.

3 GAS TURBINE TECHNOLOGY – NEW-BUILD

3.1 Ansaldo Energia

Figure 4 shows the overview of Ansaldo's gas turbines' hydrogen capabilities.


H_2 combustion technology portfolio on different GT classes for a wide array of applications

Gas Turbine	Current Capability* H_2	Application	Retrofit Solution
GT36	70% vol	Combined Cycle & Combined Heat and Power Plants	✓
GT26	45% vol		✓
AE94.3A	25% vol	Open Cycle, Combined Cycle & Combined Heat and Power Plants	✓
AE94.2	25% vol		✓
AE64.3A	5% vol		✓

*Dry premix combustion, No dilution

Standard hardware + combustion tuning

Figure 4: Ansaldo Energia Current Portfolio for H2 burning /2/.

Ansaldo offers hydrogen fuel flexibility with their standard gas turbine combustor hardware, benefitting from the two-stage combustion concept of the GT36 and 26. The GT36 can be operated up to 50% volume hydrogen without hardly penalizing the power output (figure 5). Between 50-70% hydrogen the engine needs to be derated. This is done by shifting fuel from the stage-1 to the stage-2 combustor. This decreases the 2nd stage turbine inlet temperature, but not the stage-2 flame temperature so that the performance penalty is limited. At 70% relative load it is estimated that de-rating reduces the power output by approximately 12% and efficiency by 1.25%. Beyond 70% relative load hydrogen operation requires wet combustion. At the time of writing this paper it is not known how much the penalization will be for 100% hydrogen volume content.

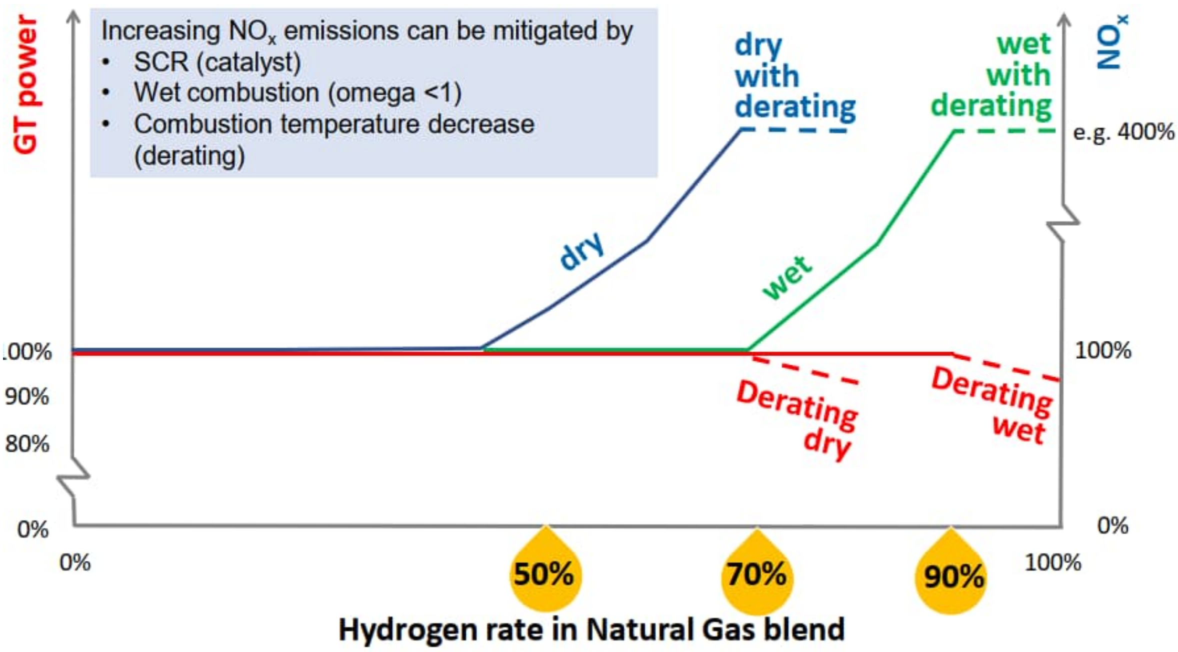


Figure 5: Hydrogen operating concept GT36 /2/.

3.2 Siemens Energy

The figure below shows the existing hydrogen capabilities for Siemens' Gas Turbine portfolio.

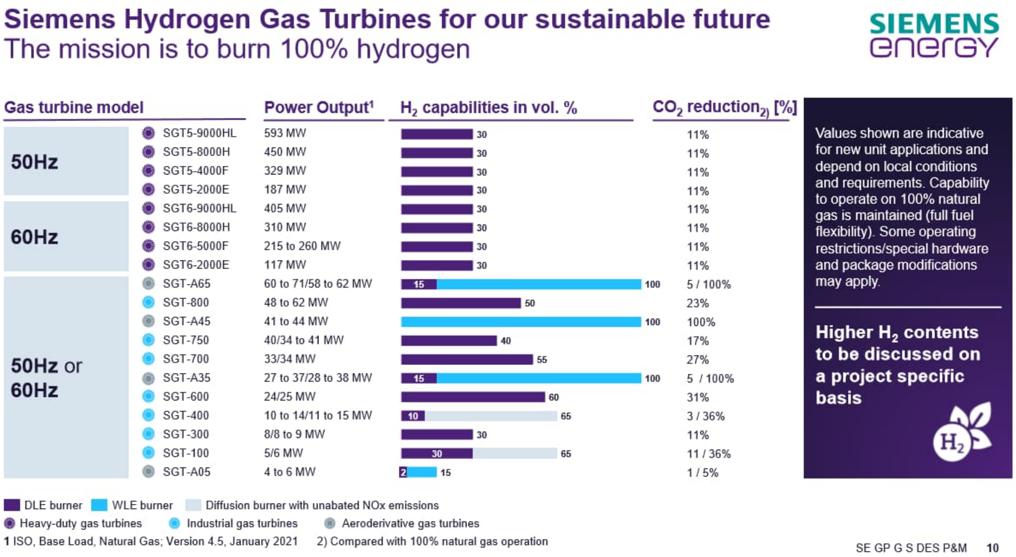


Figure 6: Hydrogen capabilities Siemens' Gas Turbines /7/.

Siemens' large heavy-duty F- and H-class Gas Turbines are capable of burning 30% hydrogen with the standard Dry Low Emissions (DLE) burners. This is an indicative number for new units, which depends on the local conditions and requirements. Higher hydrogen contents need a review on project specific basis and operating restrictions, special hardware and package modifications may apply as per figure 7.

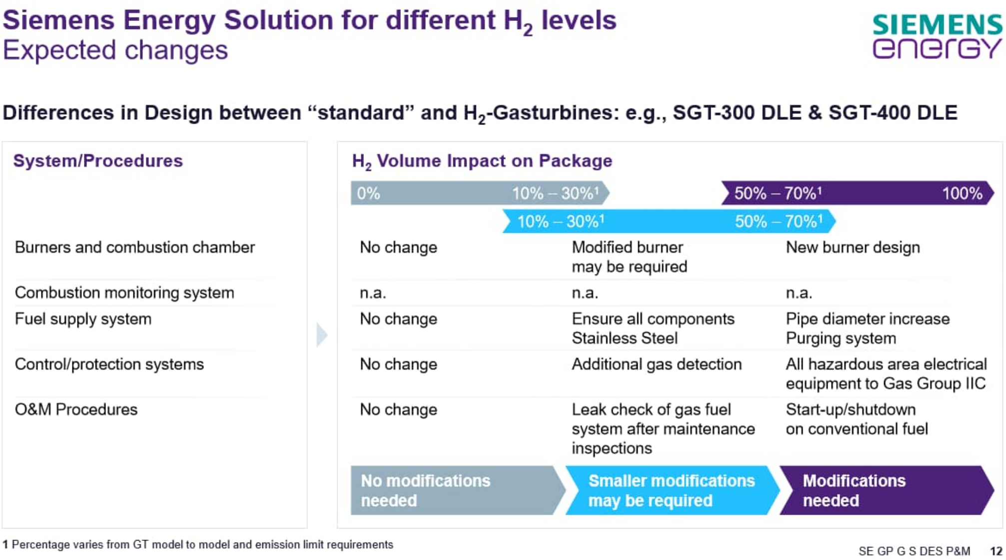


Figure 7: Hydrogen volume impact on Siemens' gas turbines /7/.

According to figure 6, there seems to be already a good opportunity to decarbonize the industrial gas turbines and aeroderivative engines with the existing hardware. For the aeroderivative (SGT-A35/45/65) this is achieved with Wet Low Emission (WLE) burners to abate the NO_x emissions, whereas for the industrial gas turbines (SGT-6000/700/8000), 50-60% hydrogen volume content can be burnt dry at low NO_x. Recent tests on the SGT-600 to SGT-800 burners demonstrated the ability to achieve 100% CO_2-free combustion in the coming years.

Decarbonizing a heavy-duty gas turbine, such as for example SGT5-4000F, is a different story. Table 1 shows the amount of water and power capacity is needed to run this gas turbine type at baseload with 15%, 30% or 100% hydrogen /7/. The example shows there is still a long way to go.

Table 1: Hydrogen requirements to operate Siemens F-Class (SGT5-4000F) /7/.

Co-firing hydrogen in gas turbines
– example SGT5-4000F

	SGT5-4000F - 15% H_2	SGT5-4000F - 30% H_2	SGT5-4000F - 100% H_2
Hydrogen [t/h]	~1.21	~2.6	~24.1
Water [l/h]	~12.100	~26.000	~241.000
Number of Silyzer 200	~58	~127	~1.176
Number of Silyzer 300	~4	~8	~71
Power demand electrolyzer [MW]	~70	~140	~1235

Indicative only based on simple cycle operation

3.3 General Electric (GE)

GE has combustion technologies that can operate on a wide range of hydrogen concentrations up to ~100% volume content (figure 8).

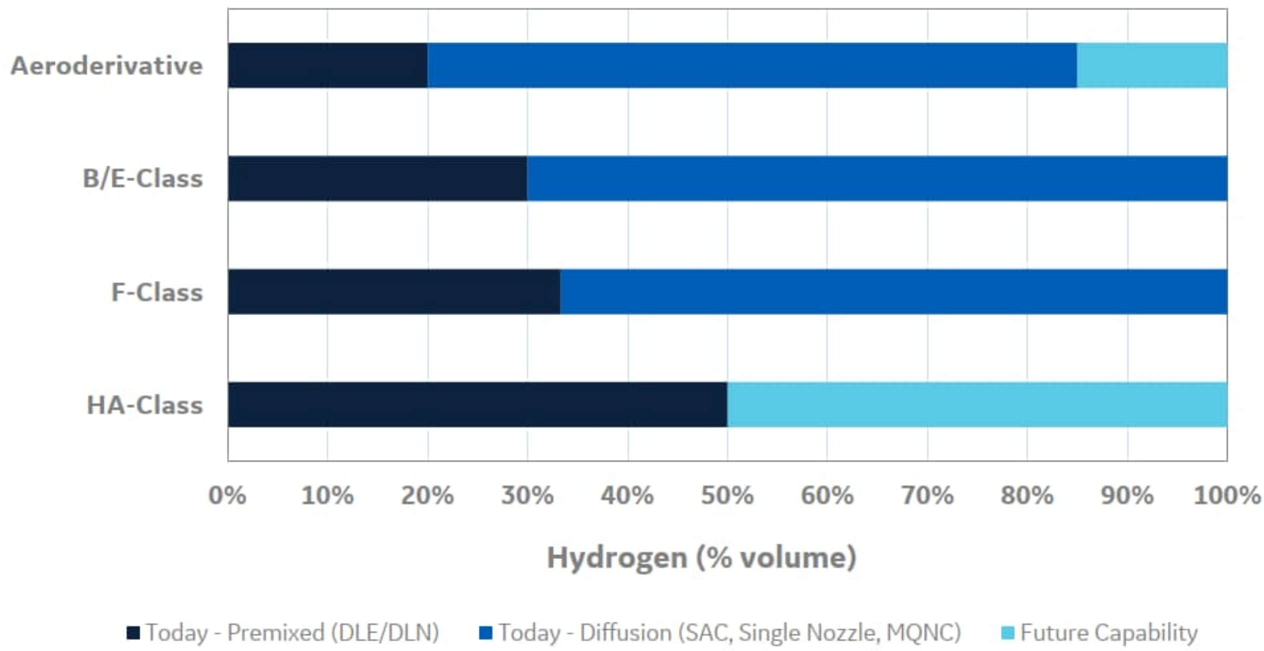


Figure 8: GE gas turbine hydrogen capabilities /11/.

As per today 100% hydrogen is achievable with B/E-Class heavy duty gas turbines, but with wet combustion. Similarly for the aeroderivative engines, which can operate close to 90% hydrogen content already, but again with WLN burners. The F-Class, 9FA, has the ability to operate with approximately 30% hydrogen volume content in dry mode, whilst GE claims the HA-Class even to be capable of 50% volume hydrogen operation (not confirmed dry or wet).

The table below shows the amount of power and water required per hour for electrolysis to supply hydrogen for operating GE's engines with 100% hydrogen at full load. For reference, an Olympic size swimming pool contains 2,500 m^3 of water; this means that an electrolyzer generating hydrogen for a 9F.04 would use an Olympic pool of water every 12 hours.

Table 2: Electrolysis requirements supporting 100% hydrogen operation /9/.

Gas Turbine	Output† MW	Heat Input† GJ/hour (MMBTU/hour)	100% H_2 Flow Rate m^3/hour (ft^3/hour)	Water Required to Generate H_2 m^3/hour (gallons/hour)	Electrolysis Power Required†† GWh
GE-10	11.2	129 (122)	~11,700 (~446,000)	~10 (~3,700)	~500
TM2500	34.3	350 (332)	~31,800 (~1,210,800)	~27 (~7,300)	~1,500
6B.03	44.0	473 (448)	~ 43,000 (~1,635,900)	~37 (~9,900)	~2,000
6F.03	87	857 (813)	~78,000 (2,970,000)	~68 (~17,950)	~3,600
7F.05	243	2,197 (2,083)	~200,000 (~7,600,000)	~174 (~46,000)	~9,400
9F.04	288	2,677 (2,537)	~243,500 (~9,266,900)	~212 (~56,000)	~11,400
9HA.02	557	4,560 (4,322)	~415,000 (~15,786,400)	~361 (~95,500)	~19,500

† ISO conditions operating on natural gas
†† Power required for electrolysis to supply H_2 flow for gas turbine to operate on 100% H_2 for 8000 hours

Increasing the electrolyzer efficiency in future will reduce some of the power needs, as would operating the on a blend of hydrogen and natural gas. Nevertheless, large sources of power and water will be needed to create a hydrogen ecosystem using electrolysis of water. GE's analysis shows that the power required for electrolysis of water to supply 100% hydrogen to an F or H-class gas turbines is larger than the curtailed future planned renewable power. Thus, creating an energy ecosystem that generates large volumes of hydrogen for use in power generation will require much larger amounts of renewable power.

3.4 Mitsubishi Hitachi Power Systems

MHPS' F and J class Gas Turbines are capable to burn 30 vol % hydrogen with today's Pre-Mix DLN burners /3/.

The use of multi-cluster combustors is investigated for 100% hydrogen firing in future. The multi-cluster combustor is currently in commercial operation with 27% hydrogen firing at Osaki and co-firing up to 80% has been completed on a test rig /3/.

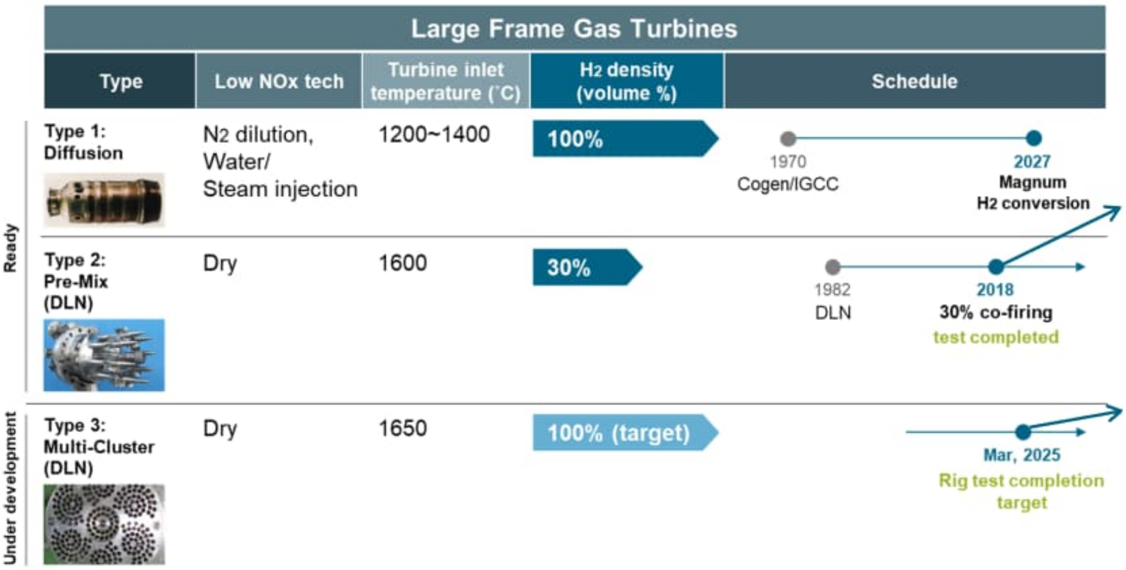


Figure 9: Hydrogen firing combustor development MHPS /3/.

4 GAS TURBINE TECHNOLOGY – RETROFIT

4.1 PSM and Thomassen Energy

Thomassen Energy offers hydrogen retrofit solutions to de-carbonize existing gas turbines in two stages /14/.

Stage 1 - LEC-III met AutoTune (GE Frame 6B, 7EA en 9E)

This is field proven technology, implemented at the 3x9E Dow Chemical site in The Netherlands, being deployed specifically for hydrogen combustion-technology development. In the past 3 years Thomassen has demonstrated hydrogen firing for volume contents of 0-35% and no impact on turbine life time, with NO_x emissions held to 9 ppm or below.

Stage 2- FlameSheet™

Thomassen has developed the FlameSheet combustor technology, simply described as a burner (or inner combustor) with a conical flame sheet around it that promotes a trapped vortex mechanism which allows higher flame velocities to be maintained.

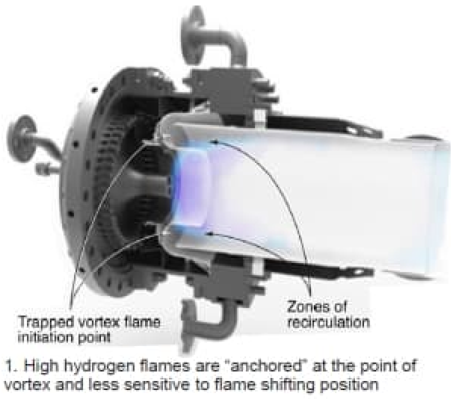


Figure 10: FlameSheet visualisation /14/.

Eight 501F and 7F gas turbines are currently operating commercially with a FlameSheet combustor. The technology offers up to 20% additional load turndown to 50% relative load and fuel flex with sub 9ppm NO_x and CO emissions. Other projects are one the way, e.g. the conversion of Linden-6 GE Frame 7F to a FlameSheet combustor using a blend of 40% hydrogen /16/.

PSM and Thomassen are participating in a Dutch-government-subsidized program to develop the FlameSheet combustor as a "platform" for 0 to 100% hydrogen firing.

In step one of the program, the company retrofitted an existing 1.8-MW OPRA OP-16 engine with a scaled version of FlameSheet and tested it for up to 100% hydrogen.

Step two will be scaling the FlameSheet to additional frame units (see figure 11), including a demo to achieve the goal of up to 100% hydrogen on units varying between 1 and 300 MW, while keeping emissions in check.

Meanwhile, a F-class unit also has been retrofitted with FlameSheet and has been field-demonstrated with a fuel mixture containing up to 5% hydrogen, the limit representing the amount of hydrogen available for this unit. The FlameSheet has been tested in the rig for F-class conditions at full pressure and full temperature for up to 60% hydrogen by volume without emissions excursions.

In addition to FlameSheet, the company has demonstrated that its AutoTune controls will greatly contribute to successful hydrogen firing. At its base, AutoTune can continuously measure the constituents of the fuel mixture, then automatically adjust the combustor fuel/air mixtures to improve combustor operation performance, thus reliability.

Maintaining low NO_x and CO emissions is a challenge with hydrogen, but premix combustion is key here and even more critical. Although conventional premix combustors are limited in their ability to burn hydrogen/natural gas mixtures, PSM sees AutoTune, combined with the aforementioned combustion technologies, as the key to successful firing in such gas turbine-equipped machines.

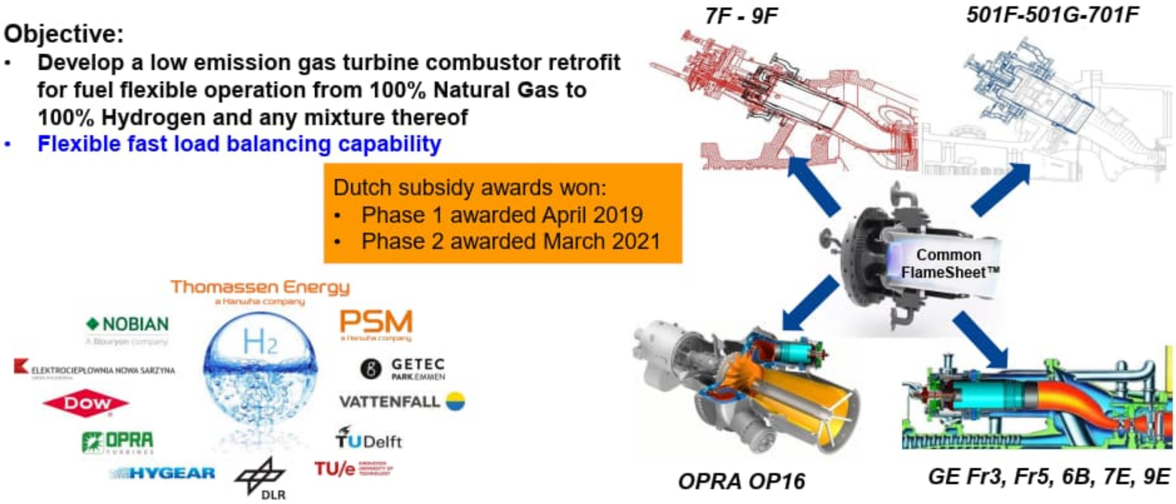


Figure 11: Step 2 – FlameSheet technology scaling for hydrogen combustion /14/.

For pragmatic entry into the H2-to-power market, Thomassen, in conjunction with OPRA Turbines of The Netherlands, offers a “turnkey clean energy package” that pairs a containerized 1.8 MWe GT/generator with a skid-mounted, packaged proton PEM or atmospheric alkaline electrolyzer driven by low-cost or negatively priced electricity to produce and store hydrogen for scheduled firing in the GT.

Figure 12: Market-entry turnkey power system pairs a containerized 1.8MWe GT (left) and a skid-mounted hydrogen generator (right).

5 DISCUSSION

Driven by the need of clean power and increasing CO_2 prices, green hydrogen is one of the technologies considered to be necessary for meeting the Paris Agreement goal of abating carbon dioxide emissions. With the thermal power generation being one of those sectors negatively impacting air emissions this White Paper aimed to explore the feasibility of using hydrogen as gas turbine fuel.

Hydrogen has in liquid form the advantage of being energy-dense, storable, light and it does not negatively impact the air emissions when burnt. As per today, 25-30% volume hydrogen content can be burnt in most gas turbines without any hardware modification and/or operating restrictions (de-rating and/or wet combustion for NO_x abatement). For some types of gas turbines the OEM claim capabilities up to about 50% hydrogen, e.g. GT36, GE9HA, SGT-800. However, to reduce the CO_2 emissions significantly, the fuel mixture should have a hydrogen volume content of at least 70%. This will come at the cost of engine performance (reduced power output and efficiency), plus the need to re-design of systems and introduction of extra safety measures (fuel supply, control & monitoring, etc.).

In addition, operating large heavy-duty F- or H-Class gas turbines requires a significant amount of power and water for producing hydrogen. With existing electrolysis efficiencies, it is unlikely that enough surplus of renewable energy will be available to operate large CCGT power plants on 100% hydrogen. Moreover, the traditional electrolysis process still relies on demineralized water quality

/10/ it will be only seawater demineralization, with its associated environmental footprint, that could really boost hydrogen as new energy source.

Nevertheless, there may be situations where green hydrogen as gas turbine fuel could well make sense, e.g. clusters with the availability of (locally) large-scale renewable power generation (off-shore wind, run-of-river hydro), water and infrastructure in combination with consumers having a high power demand.

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