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HYDROGEN CAPABILITIES OF SIEMENS ENERGY GAS TURBINES, AN OEM PERSPECTIVE

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ABSTRACT

This paper provides an overview of hydrogen capabilities of Siemens Energy gas turbines, ranging from SGT-A05 with 4 MW to SGT5-9000HL with 593 MW. First, basic challenges of hydrogen combustion are presented, regarding both the combustion, as well as handling and safety, of hydrogen systems. Results from recent technology development projects are presented, including validation tests under engine conditions at Clean Energy Center (CEC) near Berlin. Additionally, details of engine validation tests will be provided.

NOMENCLATURE

ACE: Advanced Combustion System for Efficiency
CCS: Carbon Capture and Sequestration
CEC: Clean Energy Center of Siemens Energy
CH_4: Methane
CO: Carbon Monoxide
DLE: Dry Low Emissions
DLN: Dry Low NO_x
GRI: Gas Research Institute
H_2: Hydrogen
H_2O: Water
HEE: Hydrogen Environmental Embrittlement
HRSG: Heat Recovery Steam Generator
IEA: International Energy Agency
LHV: Lower Heating Value
NO_x: Nitrous Oxides
PCS: Platform Combustion System
SE: Siemens Energy
SMR: Steam Methane Reforming
ULN: Ultra Low NO_x
WI: Wobbe Index (=LHV/ (relative density ratio)$^{0.5}$)
WLE: Wet Low Emissions

1. INTRODUCTION

Hydrogen is a promising fuel on the way to achieving future decarbonization targets. Being a feedstock to industrial processes, such as in refineries or for production of fertilizers, hydrogen already exceeds an annual production volume of 75 million tons. The vast majority is generated from conventional carbon emitting processes, such as steam methane reforming (SMR), and the IEA estimates 830 million tons of CO_2 emissions from hydrogen production – equivalent to the combined emissions of Indonesia and Britain (IEA, The Future of Hydrogen, 2019). As hydrogen can also be generated from water and electricity via electrolysis, without emitting carbon, depending on the electricity source, it enables a sector-coupled economy, where, for instance, surplus renewable energy can be converted into a green feedstock for the industrial processes. This value chain, often referred to as Power-to-X, is an important element in the path towards deep decarbonization. Current challenges include the development of an appropriate infrastructure to support not only the production but also the distribution of hydrogen at large scale. Recent forecasts (Bloomberg, 2020) expect the hydrogen market to grow by more than 8 times by 2050 from today's approximately 75 Mt/year, and while the current feedstock market is expected to remain flat, new applications in transport, as well as in power generation, are expected to emerge. Specifically, for the power generation sector hydrogen has the benefit of future-proofing both existing investments, as well as investments into new gas turbines. By blending hydrogen with natural gas, for example, the carbon footprint can be gradually reduced or even eliminated by modest engine modifications and the economic lifetime of existing, reliably operating gas turbines can be extended even with the arrival of stricter carbon emission rules. Siemens Energy has developed several gas turbines that can be operated with hydrogen as primary fuel. Traditionally, utilization of hydrogen in gas turbines has been via diffusion combustion, where fuel and air are introduced into the combustor without premixing. This technique is inherently safe against flashback and auto-ignition. Earlier applications used diffusion combustion systems with steam or N_2 injection for NO_x control. Many aspects of hydrogen handling have been addressed in these systems, including safety, leakages, embrittlement and cracking. Despite its convenient features, diffusion combustion using diluents for NO_x emission control is associated with high capital investment related to equipment and auxiliary systems, as well as additional operating expenses, and especially burdened with a penalty for plant efficiency. Consequently, recent applications utilize dry low NO_x (DLN) systems for NO_x control, with the capability to burn up to 60 vol% H_2 and the potential to achieve 100 vol% H_2, without any dilution. Siemens Energy has recently accelerated its efforts to extend hydrogen dry low emissions capability to its entire product range. This led to a solid commitment as part of the recent EUTurbines announcement (EUTURBINES, 2020) to make Siemens Energy gas turbines 100% H_2 capable by 2030 to serve customer needs.

2. CHALLENGES OF HYDROGEN IN GAS TURBINES

Utilization of hydrogen as gas turbine fuel poses some challenges due to its physical and chemical properties. These challenges require special measures for the combustion system, as well as for the fuel and safety systems.

2.1. Fundamentals of hydrogen combustion

One of the primary difficulties associated with hydrogen combustion is increased reactivity, which is characterized by increased laminar flame speed and reduced ignition delay time. In **Figure 1**, calculated laminar flame speeds of hydrogen and methane mixtures are shown for different adiabatic flame temperatures. These chemical kinetics calculations have been carried out with GRI3.0 mechanism (Gregory P. Smith, 2021) at 20 bar pressure and 450°C air temperature at constant adiabatic flame temperature. As these data indicate, laminar flame speed is increased steadily as the hydrogen ratio is increased, initially with a relatively low slope and a much stronger increase in higher hydrogen range. It should be noted that these estimates, with a flame speed increase of up to 3.5 times, are relatively mild compared to other values in the literature (Brower, et al., 2012), with flame speed increase of well above 10 times, where flame temperature increases as the $H_2/(CH_4+H_2)$ fraction is increased, if the equivalence ratio is kept constant. A dominating design parameter in gas turbine combustion systems, however, is the combustor exit / turbine inlet temperature. Therefore, a reasonable comparison of H_2 / CH_4 mixtures vs. pure CH_4 should be made at constant flame temperature rather than constant equivalence ratio. In practical design systems it is obvious that not laminar but rather turbulent flame speed should be used. Turbulent flame speed is known to increase even stronger with increasing H2 content than laminar flame speed. Turbulent flame speed correlations typically are not easily available for the needed conditions in gas turbine combustors, esp. related to high pressure ratio and turbulence conditions (Yu-Chun Lina, 2014). Therefore, laminar flame speed is a good indicator only for increased flash back risk, and the related problem needs to be addressed in the design by unsteady numerical analysis and experimental validation.

Increased flame speed leads to the following main issues:

- Risk of flashback in premix combustion systems, which can cause significant damage due to overheating and combustion dynamics
- Increased NO_x emissions due to flame position moving upstream
- Change of combustion induced pressure pulsations, which potentially can lead to combustion system damage due to change of flame shape leading to a change of the thermo-acoustic response of the flame

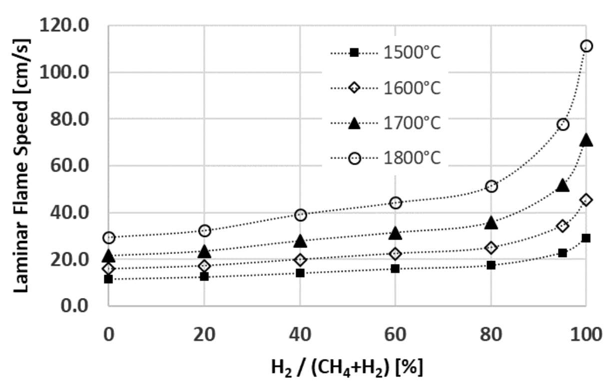

Figure 1: Laminar flame speed of H_2+CH_4 mixtures under gas turbine relevant conditions

Ignition delay time vs % H_2 content is shown in **Figure 2** for hydrogen/methane mixtures at 20 bar pressure and 750°C temperature for constant adiabatic flame temperatures, as calculated with the GRI3.0 mechanism (Chemkin 2, module Senkin). There is a steep reduction in ignition delay time for the initial 20% hydrogen, and further increases in hydrogen lead to only gradual reductions in ignition delay time. Contrary to flame speed, there is only little impact of adiabatic flame temperature / stoichiometry on the ignition delay time.

The main physical significance of ignition delay time reduction is observed as auto ignition in the mixing zone of the premix burners, or slightly downstream of the mixing duct in regions where flame is stabilized, for example by external recirculation, where hot gas is mixed with fuel air; this second example is motivation for the selection of 750°C for the calculation of ignition delay time.

- This could lead to periodic flashes in the mixing zone, followed by a steady flashback. Local zones of recirculation in wake regions behind any flow disturbances and boundary layers are especially critical for auto ignition-based flashback.
- Stabilisation of flames by external recirculation will occur closer to the burner with H_2 mixtures, which itself can again impact:
    - Emissions
    - Combustion system thermo-acoustic response
    - Overheating of combustion system parts

To prevent auto ignition with hydrogen, all fuel-containing wake regions should be eliminated by proper aerodynamic design of mixing zone and fuel injection. To avoid flashback in wall regions, fuel concentration should be low along walls and boundary layers should be purged with air.

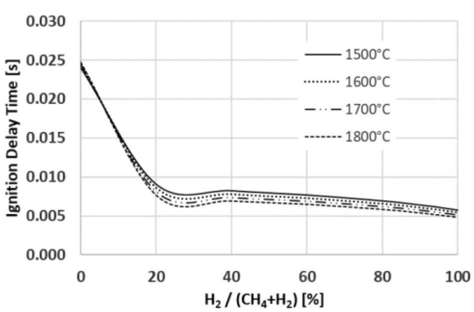

Figure 2: Ignition delay time of H_2+CH_4 mixtures under gas turbine relevant conditions

Additional changes are observed in the flame region as the hydrogen ratio is increased. First, the reaction zone moves upstream, as expected from the increased flame speed and reduced ignition delay time results presented above. Moreover, the flame gets more compact as the hydrogen ratio increases, which is expected due to increased reactivity.

Due to changes in the position and size of the reaction zone, it is expected that the thermo-acoustics of combustion are also affected. The geometry of combustion systems typically dominates excitable acoustic eigenmodes, and various flame coupling mechanisms can change related to the use of H_2.

2.2. Emissions

In this section, the effects of high-hydrogen combustion on the emissions of NO_x, CO and CO_2 are discussed. While the impact of H_2 addition on CO_2 is straightforward (**Figure 3**), assessment of changes to NO_x and CO requires more analysis.

CO_2:

Obviously, CO_2 is decreasing with increasing H_2 fraction in the fuel; however, up to a fraction of approx. 70% H_2 the CO_2 reduction increases relatively slowly to approx. 25%. Therefore, the message is clearly related to decarbonisation – significant replacement of CH_4 by H_2 is required to be successful to achieve decarbonisation by addition of H_2 to natural gas.

CO and NO_x:

CO and NO_x are strongly related to the design of the combustion system. NO_x formation in particular is strongly related to temperature distribution in the combustion system. Avoiding temperature peaks has made lean premixed technology the standard approach to achieve low NO_x emissions. The most used fundamental design feature to mix fuel with the available air is the "jet in crossflow" approach where the fuel is injected through relatively small holes (diameter d) into air. The mixing of this arrangement can, for example, be characterised by the jet penetration x, which is dominated by the ratio of momentum fluxes of fuel and air:

$$x/d \sim \sqrt{\frac{\rho_{fg} * c_{\mathrm{fg}}^2}{\rho_{air} * c_{\mathrm{air}}^2}} \qquad \textbf{Equation 1}$$

where

This is a key design parameter for lean premixed burner technology. After a few straightforward transformations, $xd \sim \sqrt{\frac{\rho_{fg} * c_{\mathrm{fg}}^2}{\rho_{air} * c_{\mathrm{air}}^2}}$ Equation 1 can be reformulated to demonstrate the impact of fuel composition, especially Wobbe index Wi. Equation 2 shows that jet penetration is directly proportional to Wobbe index and adaptation of fuel injectors may be needed to make sure that the mixing quality for a change in fuel composition is enough to achieve target NO_x emissions. It should be noted that the ideal H_2 penetration and mixing is not necessarily the same as natural gas, as additional consideration should be given to fuel placement and distribution due to flashback risk.

$$\frac{\left(x/d\right)_{real}}{\left(x/d\right)_{Design}} \approx \frac{Wi_{design}}{Wi_{real}} \qquad \textbf{Equation 2}$$

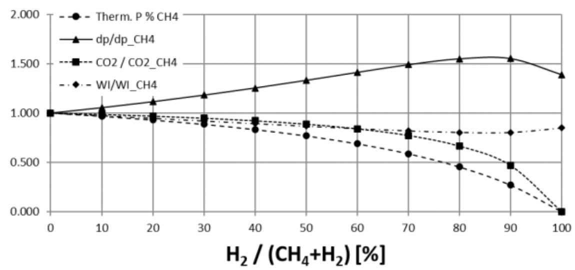

Figure 3: Variation of thermal power from CH_4 and ratio of pressure drop, CO_2 and Wobbe index relative to CH_4 for H_2+CH_4 mixtures

Figure 3 shows some important parameters, such as thermal power from methane, pressure drop over fuel injection, CO_2 production and the Wobbe index as a function of volumetric hydrogen ratio in relation to that of methane.

The impact of mixing changes on NO_x emission due to H_2 addition in practice requires reacting CFD capturing mixing and chemical kinetics and mixing tests, typically followed by a combustion test for validation.

In addition to this aerodynamical design task there is another challenge to NO_x and CO emissions when using H_2 addition to natural gas, namely the way of measuring emissions and how often emission regulation / permitting is done.

NO_x and CO are mostly measured by extractive methods using probes in the exhaust duct. Traditionally (and defined per standards as well), H_2O is extracted from the sample before the measurement for various reasons like condensation in sampling equipment, cross-sensitivities and more. Burning H_2 at same thermal input as with CH_4 produces, however, more H_2O. Extracting this H_2O for the measurement of NO_x, CO and other components in the exhaust is equivalent to an increased concentration of the NO_x content in the dry sample.

$$\boldsymbol{NO_x(dry, 15\%\, O_2)} = \left[\boldsymbol{x_{NO}} + \boldsymbol{x_{NO_2}}\right]$$

$$* \frac{1}{(1 - x_{H2O})}$$

$$* \frac{0.2089 - 0.15}{0.2089 - x_{O_2}}$$

Equation 3

In Equation **3** the term

$$\frac{1}{(1 - x_{H2O})}$$

represents the impact of measuring after H_2O extraction. For H_2 compared to CH_4 driven turbine running at approx. 1700°C combustor exit this represents a "penalty" factor for the H_2 turbine of 7% (**Figure 4**).

Often, emissions are permitted in units of volume content at defined conditions normalized to a reference condition, for example parts per million volume dry at 15% O_2 (ppmvd, 15%O_2). This also adds a burden for H_2 combustion because there is a change of excess O_2 in the exhaust at the same thermal load. In addition, O_2 also – again – is measured dry, meaning after extraction of H_2O.

In Equation **3** the term

$$\frac{0.2089 - 0.15}{0.2089 - x_{O_2}}$$

represents the impact of normalising emission to an O_2 reference value of 15%, measured O_2 after H_2O extraction. For H_2 compared to CH_4 driven turbine running at approx. 1700°C combustor exit this represents a penalty factor for the H_2 turbine of 28% (**Figure 5**).

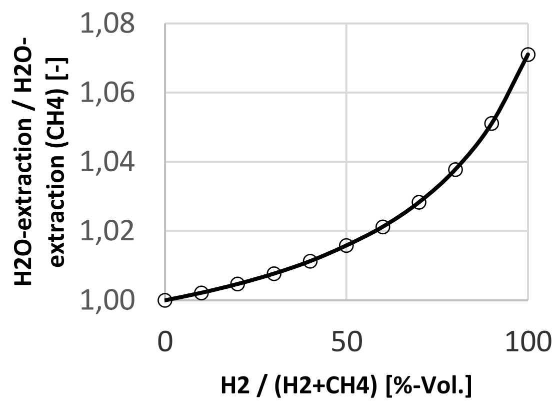

Figure 4: H_2O extraction factor

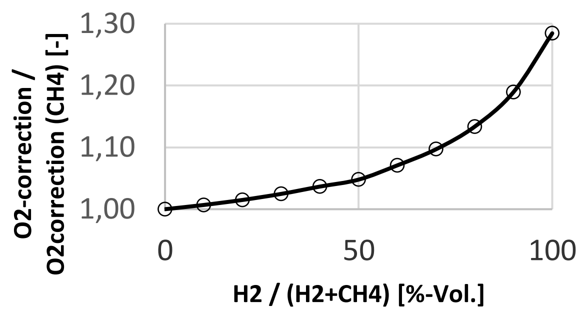

Figure 5: O_2 correction factor

Both **Figure 4** and **Figure 5** show an increasing trend with increasing fraction of H_2 in an H_2 / CH_4 mixture. Both trends depend on the equivalence ratio and corresponding flame temperature for a certain frame. The shown example represents a flame temperature of 1700°C. Both factors add up to a penalty of almost 35% when comparing NO_x from the H_2 turbine to NO_x from the CH_4 turbine; the higher the temperature of the combustion system the larger these factors will be. Under such regulatory standards H_2 turbines would require engine derating by approx. >25K (or equivalent -0.4%-pts in combined cycle efficiency) to compensate for this H_2-penalty. A recommendation from this simple mass balancing study is that attempts must be made to:

- Change emission regulation to gr / MWh, gr / kJ or similar units
- Correct for H_2O extraction in emission sampling lines or measure wet.

2.3. Fuel system requirements

Fuel systems of high-hydrogen combustion systems must fulfil certain requirements due to physical and chemical properties of hydrogen. First, owing to the lower volumetric heating value of hydrogen compared to natural gas, higher volume flows require larger size pipes and fittings to keep fuel supply pressure within the required limits. Second, and perhaps more important, are the materials used in the fuel system, which might be subject to hydrogen embrittlement, namely, degradation of certain mechanical properties due to gaseous hydrogen and applied stress. Although there exist multiple mechanisms for this degradation, the one most related to fuel systems is called Hydrogen Environmental Embrittlement (HEE), which occurs due to diffusion of hydrogen into metal and subsequent reactions with metal carbides, producing CH_4, which cannot escape, thus creating local deposits (blisters) or micro cracks (Lee, 2016). There are suitable stainless-steel choices with negligible to low HEE properties, with 316L being the best austenitic steel variant (EIGA, 2014), (San Marchi & Somerday, 2012). However, existing installations cannot always be converted to 316L steel and must be checked for intended hydrogen pressure and temperature to exclude any degradation risks.

To prevent leakages, material modifications might be needed. Pipe joints could require additional sealing as well. Usually, connections and flanges are welded together, including bolt holes, to prevent any leakages, creating a permanent connection which can be disconnected only by cutting the flange connection.

Despite all modification's hydrogen leakages are more likely to occur compared to other fuels due to hydrogen's small molecular size, which necessitates further safety measures. These measures include proper design of enclosed volumes, with leakage detection, explosion proof electrical equipment and proper ventilation. It is expected that hydrogen leakages will rise to the highest point of enclosures due to low density of the gas. Thus, it is suggested to ventilate closed enclosures through the highest point. Owing to wide flammability limits of hydrogen (4 to 75 vol%), improper enclosure designs and insufficient explosion protection might still lead to accidents, as recently observed in hydrogen filling station incidents in Norway and California, where a faulty plug and faulty flange caused a leakage and an explosion (Mario Pagliaro, 2019).

Further protective measures are necessary for fuel systems as far as electrical equipment is concerned. Generally, ATEX 2C or International Electrotechnical Commission (IEC) gas groups IIC and IIB+H_2 compliance is necessary for electrical equipment. For the flame detection in the package enclosure a combination of ultraviolet (UV) and infrared (IR) detectors might be required

2.4. Combustor modifications

The combustor is the most impacted component in a high hydrogen gas turbine. Depending on the ratio of hydrogen, modifications, from simple control and protection modifications for low hydrogen ratios to complete replacement of combustion system for higher hydrogen ratios, might be required. Additionally, depending on the performance targets to be achieved, a hybrid strategy might be selected, comprising partial derating and introduction of an upgrade package. Combustion control systems may require modification to adapt to the changes in fuel properties when increasing the hydrogen content in the fuel to control NOx emissions, as well as mitigating the risk of flashback or pulsation damage. Siemens Energy already has control systems which are capable of operating GTs at sites with multiple gaseous fuel streams, including sites where the streams are mixed and have higher H_2. The main change that is happening now is that the H_2 content is anticipated to further increase, therefore, the flashback risk increases and drives the need for better flashback detection/prediction. Gas analysis devices are used in the fuel line, in order to measure the changes in gas composition and to adapt the control parameters. These devices are redundant and sufficiently fast, with response times shorter than 20 seconds and are placed sufficiently upstream in fuel line, allowing proper control of gas turbine parameters as hydrogen concentration varies.

In certain cases, start-up and shutdown is carried out with standard fuels to eliminate risks during transient operation. Depending on the concentration and engine configuration, the use of additional instrumentation may be required which would be monitored by the control system to avoid flashback and associated damage. Additional redundant hydrogen concentration measurements are used to activate control measures, such as de-rating or shifting fuel between fuel stages.

2.5. Hot gas path impact

High hydrogen combustion impacts heat transfer and the lifetime of hot gas path components in the combustor, turbine, exhaust diffusor and HRSG. Owing to increased water vapour in combustion products, exhaust gas properties can impact heat transfer and corrosion rates, possibly impacting the life of components. Usually, a plant specific study is needed to analyze all factors and develop the most appropriate solution.

3. TYPES OF HYDROGEN OPERATION IN GAS TURBINES

Hydrogen operation in gas turbines can be either wet (using dilution steam / water for NO_x control) or dry, depending on several factors, including combustor design, availability of steam or water, emission regulations, performance requirements, lifetime impact, cost and engine type.

3.1. Conventional combustors

Traditionally, gas turbine combustion systems were diffusion or partial-premixed type, which require water or steam injection for emissions control for hydrogen operation. A sliced conventional combustion system of SGT-600 is shown **Figure 6** with diffusion type fuel injection without premixing and separate demineralized water or steam nozzles for emission control.

Such conventional combustors can be operated up to 100% H_2 without any flashback issues, as diffusion flames do not have premixing zones. However, due to the high flame temperature for diffusion flames (which always burn stoichiometrically) and therefore very high NO_x emission that can to some extent be mitigated by water injection (Geipel, 2012), the availability and cost of demineralized water may also be a problem for the customer. The conventional combustion systems have nowadays been replaced with DLE combustion systems (also for the SGT-600).

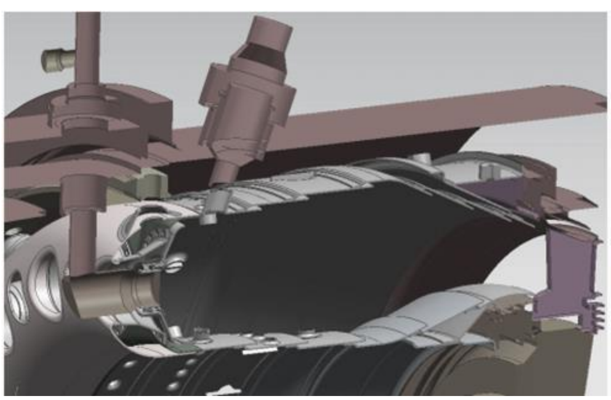

Figure 6: SGT-600 Non-DLE combustion system

3.2. Dry low emission combustors

Emission control technique based on dry low emission technologies (DLE) was developed over the last four decades. The key design feature of DLE is the homogenous premixing of fuel and air at lean composition prior to flame stabilization, in order to eliminate excessive temperature peaks in the combustion system, not only globally but also locally.

Typical DLE combustion systems are shown in **Figure 7**, **Figure 8**, **Figure 9**, **Figure 10** and Figure **11** for the SGT-400, SGT-600, SGT-5000F, SGT-4000F and SGT5/6-9000HL engines, respectively.

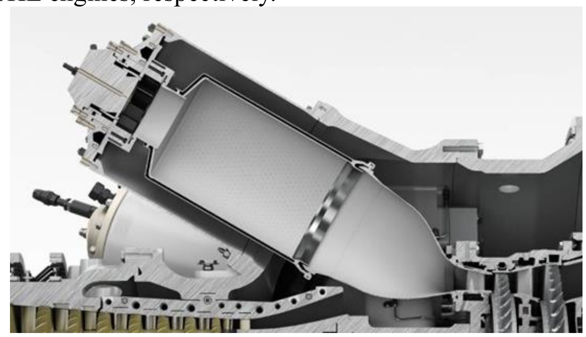

Figure 7: SGT-400 DLE can combustion system

The distinguishing feature of the DLE combustion system is the introduction of a mixing zone, where fuel and air are introduced and mixed prior to entering a reaction zone where combustion takes place. The G30, AEV, HR3 and ULN/PCS technologies from the SE gas turbine portfolio are well known and proven injector/burner technologies with millions of operating hours of experience.

Figure 8: 3rd Generation DLE combustion system of SGT-600 gas turbine

These burners are installed in combustion systems of three main architectures – annular, can-annular and large silo type combustors.

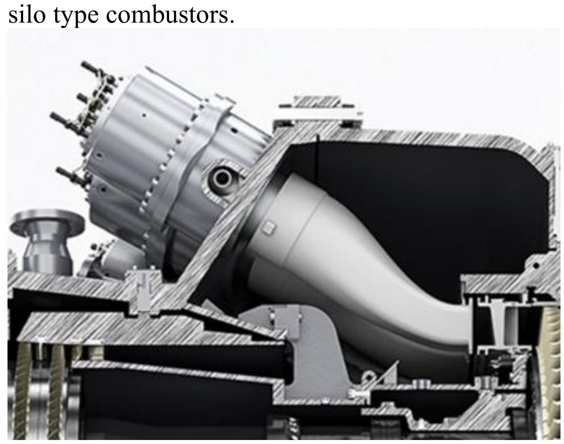

Figure 9: SGT-5000F can combustion system

DLE systems provide a major technology jump over conventional combustion systems, as the need for distilled water or steam is eliminated with efficiency, lifetime and emission improvements and major cost savings. However, introduction of DLE systems carries a flashback risk because of utilization of a mixing zone which did not exist in conventional systems. Additionally, DLE systems tend to be more unstable as far as thermoacoustic instabilities are concerned. Combustion of high-hydrogen fuels in the existing DLE systems has fundamental limitations due to flashback risk and thermoacoustic instabilities, as well as increased NO_x emissions.

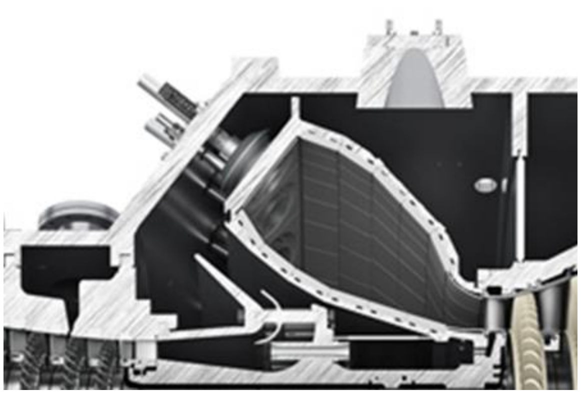

Figure 10: SGT-4000F combustion system

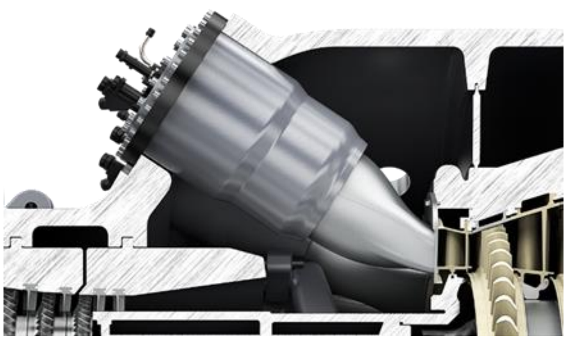

Figure 11: SGT5/6-9000HL combustion system

4. HYDROGEN CAPABILITIES OF EXISTING SIEMENS ENERGY GAS TURBINES

Currently, the hydrogen capabilities of the Siemens Energy gas turbine portfolio for new unit applications vary widely depending on the type of combustion system utilized (DLE, WLE or diffusion burners), operation pressure and temperature of the engines, and the frame sizes; see **Figure 12**.

There are several high-hydrogen gas turbine applications from Siemens Energy as shown in

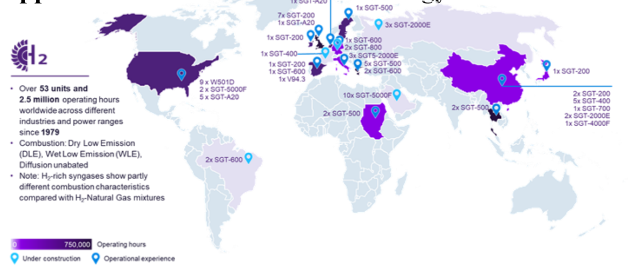

Figure **13**, with some under construction and some operational (shown with light and dark symbols, respectively). These applications helped Siemens Energy to gain experience with all aspects of high-hydrogen operation, ranging from materials to safety and combustion. Some examples are highlighted in more detail in the following section

4.1. Small industrial gas turbines

SE small industrial gas turbines SGT-100, 200, 300 and 400 use G30 burner technology, a proven radial swirler premixing design which has gone through significant fuel flexibility programs, driven by petrochemical customer demand. This combustor technology has the ability to burn mixtures of hydrogen and methane up to 30 vol% on the SGT-100 and 300, which is being further developed for increased hydrogen fractions through the Siemens Energy hydrogen roadmap. The SGT-400 combustion system has been developed to run on up to 10 vol% hydrogen (Lam, 2016).

The non-DLE combustion systems of the SGT-200 and SGT-400 have over 1 million operating hours in coke oven gas applications, which are characterized by high hydrogen (50-65 vol%) content and significant amounts of carbon dioxide and carbon monoxide. The SGT-200 has refinery gas experience, with contents of hydrogen up to 85 vol% and with more than 800,000 operating hours.

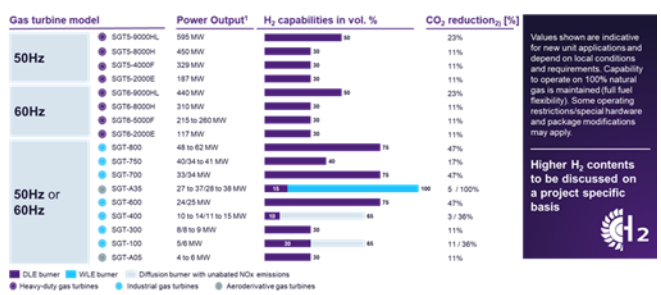

Figure 12: SE gas turbine portfolio hydrogen capability for new unit applications with high hydrogen option

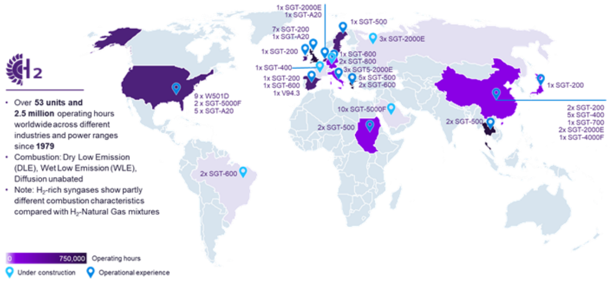

Figure 13: High-hydrogen gas turbine applications from Siemens Energy

4.2. Medium industrial gas turbines

DLE operation of the SGT-600, 700 and 800 is based on 3rd generation DLE technology with a cylindrical duct downstream of a conical swirler for optimal premixing. Over the last decade, further development and testing of the burner has steadily improved its hydrogen capability. Rig and engine testing over the last ten years has cleared 60 vol% hydrogen on the SGT-600, 55 vol% on the SGT-700, and 50 vol% on the SGT-800. The SGT-600 has run an engine test with close to 80 vol% hydrogen (Magnussson, 2020), and an AM manufactured hydrogen adapted 3rd generation DLE burner, that is used in all three engines, was tested at the Siemens Clean Energy Center near Berlin in 2019 with hydrogen up to 100% in mixture with natural gas at engine-like conditions. This significant achievement was enabled by additive manufacturing as shown in **Figure 14**, which allowed for fast iterations via rapid prototyping and more efficient combustion system aerodynamics.

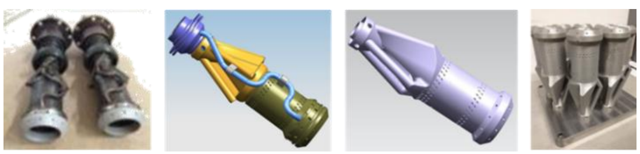

Figure 14: SGT-600, SGT700 and SGT-800 burner design welded with AM repaired burner tip to SLM manufactured still to be cut from printing plate (far right)

Siemens Energy has sold two SGT-600 engines for a project in Brazil that will be commissioned during the summer of 2021 to operate on process gas with about 60 vol% hydrogen (Magnussson, 2020).

The SGT-750 (38 MWe, 40% efficiency) is equipped with the 4th generation DLE burner. The 4th generation burner has a central premixed pilot with a radial main swirler. The 4th generation burner has been tested for various fuel compositions, including hydrogen-methane mixtures, and the SGT-750 has proven operation up to 40 vol% hydrogen fuel (Lindman, June 2017). The SGT-750 is currently being developed for low carbon operation.

On the non-DLE side, SE has gained extensive experience with high-hydrogen fuels on SGT-500 and SGT-600 industrial gas turbines burning refinery fuel gases with up to 90 vol% hydrogen content. For example, 10 SGT-500 units in the field have gathered more than 800,000 combined operating hours on high-hydrogen fuels using non-DLE systems since 1979.

4.3. Aero-derivatives

The SE aero-derivative engines use axially staged DLE burners with radial swirlers in the primary stage and secondary non-swirling premixing ducts axially downstream, which are stabilized by the hot gases from the primary stage. Axial staging is commonly used in multi-shaft engines to ensure optimal operability for all load conditions and to minimize thermo-acoustics as the heat release profile through the combustor can be varied for a given constant power. The SGT-A35 have the capability to run with up to 15 vol% hydrogen today, and the A05 is capable of 30 vol% hydrogen.

Non-DLE systems in the SE aeroderivative gas turbine family are adapted from aerospace engine applications. These systems can operate on both gas and liquid fuels, with NO_x controlled by using water injection to reduce flame temperature. The SGT-A65 and SGT-A45 share the Phase V combustion system, while the SGT-A35 uses the Phase II combustion system. The SGT-A65, SGT-A45 and SGT-A35 non-DLE engines are all capable of operating on 100% hydrogen. The A05 is capable of 30 vol% hydrogen with a non-DLE system with water injection. The SGT-A20 has significant experience operating on high-hydrogen fuels (up to 78 vol%) in petrochemical applications. Rig testing of the SGT-A65 and SGT-A45 combustion system has been conducted to understand the emissions characteristics of hydrogen-methane mixtures and pure hydrogen with water dilution.

4.4. Large gas turbines

SE heavy-duty large gas turbines SGT5/6-2000E and SGT5/6-4000F use the HR3 burner design. Based on a hybrid burner concept, the HR3 has a central pilot swirler and a concentric diagonal swirler with gas injection through the swirler vanes (SFI). The SGT6-5000F and SGT5/6-8000H use Ultra-Low NO_x Platform Combustion System (ULN/PCS) systems which integrate SFI technology into a premixed pilot and concentrically arranged main swirlers. These burners combined have accumulated many millions of operating hours and offer a wide range of fuel flexibility, including the capability to run on mixtures of natural gas and up to 30 vol% hydrogen. The latest SGT5/6-9000HL engines use the Advanced Combustion for Efficiency (ACE) system, which can also run on up to 50 vol%. hydrogen. By 2030, the large gas turbine DLE systems are targeted to be capable of running on 100% hydrogen.

SE has recently sold a 2000E utility scale gas turbine to a customer in the petrochemical industry, with the requirement to run on up to 27 vol% hydrogen starting in 2020. This extension of the Siemens Energy standard capability was achieved through incremental and retrofittable changes to the geometry of the burners to improve flashback resistance at higher hydrogen contents. It was tested and validated through a high-pressure combustion test at engine conditions. Validation testing has indicated that NO_x emissions will not exceed 50 mg/Nm^3 during both operation on natural gas and with the hydrogen fuel mixture.

Hydrogen capability of SE energy gas turbines is not limited only to the examples presented above. All SE heavy-duty gas turbines can be operated with up to 30% hydrogen. However, it should be noted that this capability is for new unit applications and depends on local conditions and requirements. In certain cases, operational restrictions or package modifications may be necessary.

Since the early 1990s, SE has gained experience operating its large gas turbine products employing non-DLE combustion technology on hydrogen fuel mixtures, specifically in applications of gasification processes with different feedstocks (coal, waste from the petrochemical industry, and biomass) and waste gases from steel mills (coke oven and blast furnace gases). These synthetic gases (syngas) are mixtures of varying composition, but typically have significant percentages of hydrogen and CO, as well as inert gases (N_2, CO_2, steam).

Around the beginning of this century, gasification processes were developed to convert coal or refinery residues via gasification and carbon monoxide (CO) shift reaction into CO_2 and hydrogen. Following conversion, CO_2 is removed prior to feeding the syngas to the gas turbine. These Carbon Capture and Storage (CCS) syngases, like hydrogen, are characterized by a very high reactivity as the thermal input to combustion is almost completely from hydrogen. Significant development of these processes occurred during the 2000s (Huth, 2000), (Hannemann, 2003) and 2010s with governmental support (EU, United States Department of Energy (DOE), and German Federal Ministry for Economic Affairs and Energy (BMWI)). One of the central focus areas of these governmentally funded programs was research and development of combustion technology for DLE systems in large gas turbines, with the goal of substantially reducing or eliminating dilution in order to maximize plant efficiency. While CCS gasification plants are not yet commercially viable, the related research into highly reactive hydrogen fuel combustion fuels has contributed to the development of future pure hydrogen capable DLE technology.

5. TECHNOLOGY PROGRAMS FOR HYDROGEN

A comprehensive technology program is currently underway at Siemens Energy to achieve 100% hydrogen targets. This program is supported across the company with a wide range of tools and facilities, including additive manufacturing facilities (Fu, Haberland, Klapdor, Rule, & Piegert, 2017), high pressure test facilities in Lincoln and Berlin, as well as engine tests.

5.1. Flow and combustion simulation investigations

Advanced CFD tools allow Siemens Energy's combustion engineers to run analyses on fuel burners to identify the key design measures needed to increase a combustion system's hydrogen fuel capabilities. Combustion CFD tools provide engineers with a clearer picture of the flame structure, as demonstrated on the SGT-800 fuel injector study in **Figure 15**. The tools are calibrated for Siemens Energy designs and verified through years of combustion development and verification testing, allowing reliable evaluation of design options in the early phases of a project. With an increasing share of hydrogen, thermo-acoustics of the flame changes as explained in Section 3. To account for this effect, Siemens Energy is engaged with universities to implement the latest advances from the research community into our tool suite, to take those effects into account during early stages of the design process.

5.2. Atmospheric and high-pressure combustion tests

Despite all the advances that were made in past years in CFD, combustion today is still a complex field. Testing of combustion systems at relevant pressure and temperature conditions is therefore still an important part of our design process. All new developments undergo rigorous testing to ensure safe operation at the customer site. An atmospheric test rig is used, with full optical access, in order to gain insight into combustion characteristics, as shown with the 3rd generation DLE burner in Figure **16**.

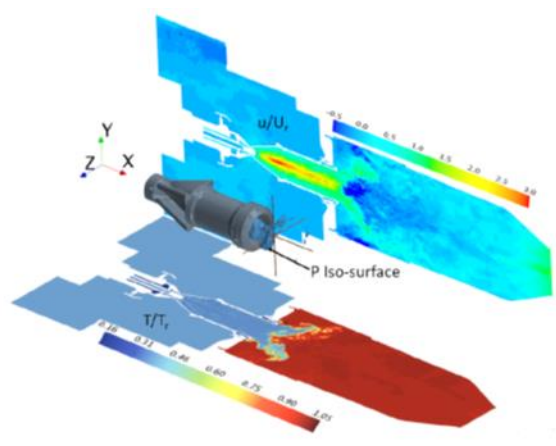

Figure 15: CFD flow field overview from a study of SGT-800 3rd generation burner with high-hydrogen fuels (Moëll, 2018)

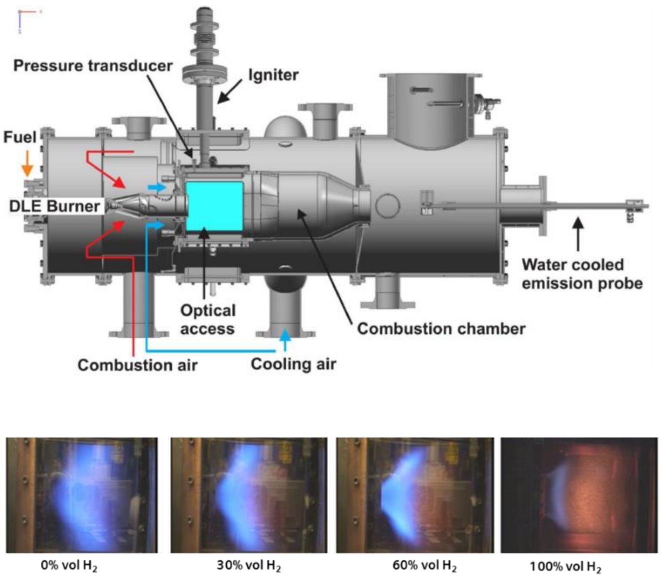

Figure 16: Flame pictures from atmospheric combustion tests in the rig shown above, as H_2 percentage is increased

The Clean Energy Center near Berlin is Siemens Energy's facility for high pressure (35 bar) combustion tests, see **Figure 17** and **Figure 18**. The facility supports testing of components and systems for the whole Siemens Energy gas turbine portfolio – from large gas turbines down to small industrial designs – and allows for a wide variety of fuels to be tested. In 2019, hydrogen testing capability was added to ensure that it can support the increased demand of hydrogen applications. With this in-house capability Siemens Energy ensures new knowledge is shared across our fleet and timely support is provided to customer projects for special fuels like hydrogen.

Figure 17: Clean Energy Center facilities for high pressure combustion tests near Berlin, Germany

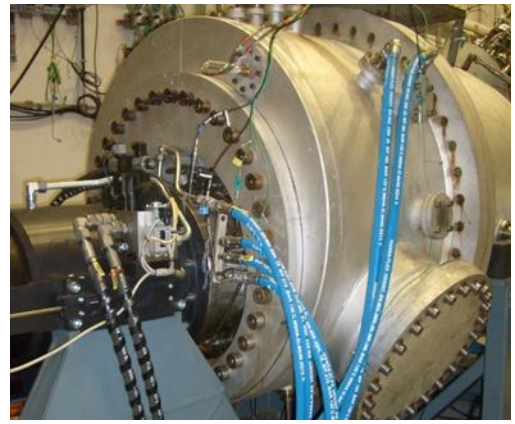

Figure 18: High pressure test rig for combustion tests

In addition to single-burner or single-can high pressure tests at CEC, further high-pressure tests are carried out in test engines by replacing only one burner with a test burner and providing this burner with high hydrogen. Flame pictures from a high-pressure test at CEC with 3rd generation DLE burner are shown in **Figure 19**. It is especially interesting that the flame is practically invisible with 100% H_2.

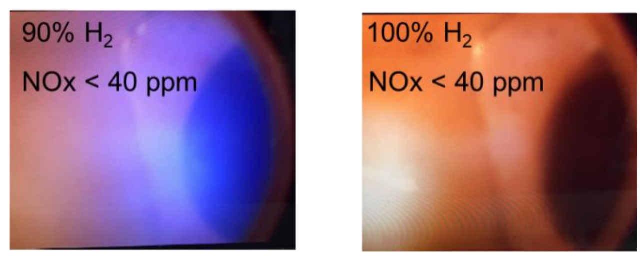

Figure 19: Single-burner high hydrogen test in CEC

6. UPGRADE STRATEGY

Siemens Energy has an ambitious technology approach to utilize a building block strategy for the development of H_2-NG flexible combustion systems for as many as possible of their gas turbine products. A set of core technology elements will be developed which can be applied across the product portfolio. The technology is planned to be initially demonstrated in the SGT-400 engine within the EU-funded HYFLEXPOWER project (SiemensEnergy, 2020) as shown in Figure **20**, the world's first industrial power-to-X-to-power demonstrator with an advanced H2 gas turbine. Initial testing will be conducted with mixtures of natural gas with hydrogen content up to 30% in 2022. The goal is to demonstrate the advanced plant concept for up to 100% in 2023. By taking this approach, the overall development timeline and cost will be minimized. Additionally, the risk for the larger, higher firing temperature gas turbines will be mitigated by first validating the technology elements in smaller, lower firing temperature gas turbines.

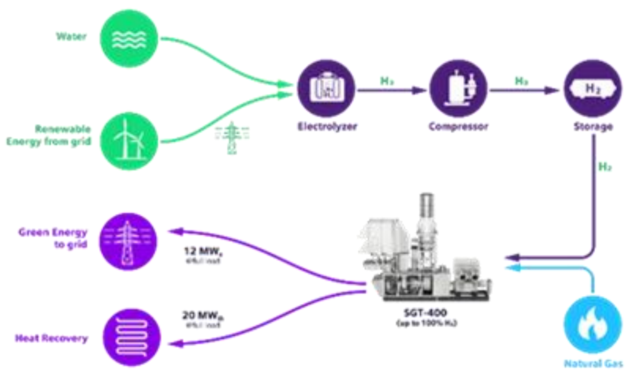

Figure 20: EU funded project HYFLEXPOWER

The SE gas turbine portfolio covers products from 4 to 593 MW and with a wide variety of pressure ratios, turbine inlet temperatures and engine architectures, not to mention customer operational requirements. This wide range of scales and requirements creates a challenge for the technologies under consideration and makes it likely that multiple technology elements (Baukasten) will be required to design combustion systems that fulfill the requirements of the entire SE gas turbine portfolio and can operate on all mixtures of fuels between 100% H_2 and 100% NG.

To address this great challenge, SE assembled a technology team of engineers with experience in all their product lines and in combustion technology development. This team identified an extensive list of potential technologies and novel design features which could contribute towards meeting the H_2 challenge. These technologies are currently being analyzed and further developed and tested at the SE CEC.

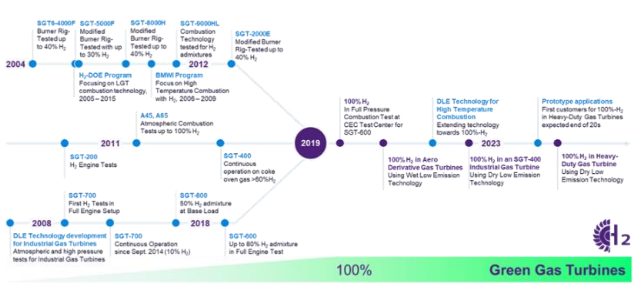

Figure 21: High-hydrogen gas turbine roadmap of Siemens Energy

Finally, the 100% hydrogen gas turbine program from Siemens Energy combines extensive technology development for industrial and utility power generation applications. Since the 1960s, Siemens Energy has gained experience with high-hydrogen fuels on non-DLE combustion systems. Beginning in the early 2000s Siemens Energy has invested in the development of DLE hydrogen combustion technology, as shown in

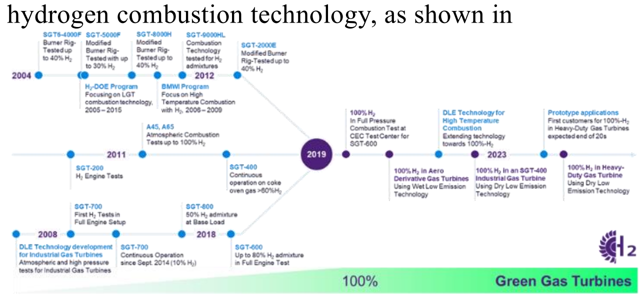

Figure 21. By 2030, Siemens Energy intends to have gas turbines with the capability of operating on 100% hydrogen fuel with DLE technology available. To achieve this target, the necessary technologies are continuously being developed and these new designs are implemented into the Siemens Energy product portfolio.

7. SUMMARY AND CONCLUSIONS

High-hydrogen combustion in gas turbines paves the way for coping with fluctuations in renewable energy generation and enables CO2-free utilization of gas turbines in a renewable-dominated market. Owing to its small and very reactive molecules, utilization of hydrogen creates new challenges with materials, safety, low-NOx combustion and the lifetime of hot gas path components. Gas turbines from Siemens Energy have extensive hydrogen experience in both wet- and dry-low emission operations. Additionally, a comprehensive technology program is underway to extend the DLE combustion systems' hydrogen capability to 100%, as part of an industry-wide commitment. This technology program is based on modern simulation and testing facilities and will be implemented across the product portfolio.

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