Hydrogen power and heat with Siemens Energy gas turbines

Reliable and flexible carbon-free energy

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Today, gas turbines play a vital role in addressing the threat of global warming and making energy greener. Gas turbines are in the category of the cleanest fossil-fuel based power generation solutions and are ideally suited to manage the intermittency of increasing renewable loads by providing reliable and on-demand power. Gas turbines will remain an even more important element in power grids as electrification trends toward full decarbonization and the hydrogen economy starts to unfold.

By burning hydrogen as a fuel, either through co-firing or complete displacement of natural gas, gas turbines can provide low-carbon or even carbon-free power solutions. Gas turbines play a key role in enabling a smooth transition from a fossil fuel-based to a fully decarbonized power system because they provide highly flexible and dispatchable generation to support future grids largely dominated by intermittent renewable power. They can also provide much needed grid ancillary services - even when the gas turbine is not producing active power -, which will become more important as the system moves to a largely renewable-dominated production. These capabilities make gas turbines ideally suited to helping to meet the World Energy Council's trilemma of secure, affordable, and environmentally sustainable energy.

In the future, increasing use of hydrogen fuels will enable the conversion of thousands of gas turbine operating units worldwide into reliable and environmentally sustainable decarbonization agents. Therefore, owners of existing gas turbine power plants and the ones soon to be developed can be confident of their plants' roles in supporting the future energy transition.

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1 Why use hydrogen as a fuel for gas turbines?

The need for hydrogen to decarbonize power generation

Global warming, caused by anthropogenic emissions such as carbon dioxide, methane, and other greenhouse gases, threatens to disrupt the ecosystems on which we all depend. In October 2018, the Intergovernmental Panel on Climate Change (IPCC) released a special report that details the impacts of global warming of 1.5 °C and higher above pre-industrial levels. Revising their original target of keeping global warming below 2 °C, the IPCC warned that warming above 1.5 °C is not sustainable in the long-term. Instead, the IPCC now recommends reducing the target for global temperature increases to just 1-1.5 °C until the end of the century [1].

The IPCC's target of limiting the global temperature rise to no more than 1.5 °C requires limiting annual global emissions to 25–30 gigatons (Gt) carbon dioxide (CO_2) equivalent per year range by 2030 [1], however in 2023 annual worldwide emissions reached 37.4Gt CO_2 [2]. The energy sector is a major contributor to global greenhouse emissions with a global share of around 44% while the remaining 56% are emitted from other sectors such as industry, mobility and residential [3]. While last data indicates that the 1.5 °C temperature limit is already difficult to impossible to reach, it is of increased importance to limit global warming to a temperature increase of below 2 °C.

For the last few decades, the focus for reducing the carbon emissions in the energy sector has been on the development of renewable generation using mainly wind and solar energy. While renewables do not produce carbon emissions, they introduce a high level of intermittency due to changing weather conditions and variations in solar irradiation. This is often coupled with mismatches between the demand and supply of energy. While demand-side management can play a large role in handling these mismatches, supply management through curtailment of renewables during times of oversupply, energy storage, and providing backup power with dispatchable, flexible conventional power plants is also required. In recent years, a variety of storage options have emerged allowing short-term storage during the day as well as long-term storage through whole seasons. While batteries are well-suited to help manage the daily peak shift from midday to evenings, energy storage in chemical form appears as the only viable solution to store energy for longer periods and for seasonal storage.

Of the conventional thermal-fuel generation technologies, combined cycle power plants are the most efficient and clean option. The switch of an existing coal power plant to a new combined cycle power plant running on natural gas will reduce specific carbon dioxyde emissions by up to 65%. Compared to separately producing electricity in a combined cycle plant and producing heat in a fossil-fuel fired boiler, cogeneration of heat and power in combined heat and power plants further reduces the specific CO_2 emissions. The total energy efficiency of modern gas turbines with cogeneration can surpass 90%.

Carbon neutrality is becoming a key long-term goal for countries and organizations. The European Union (EU) has set an example by aiming to reach this goal by 2050 and 90% CO_2 emission reduction by 2040. However, switching from coal to natural gas power generation and improving efficiency can only be the first step towards it. After replacement of coal power stations with new gas-fired power combined-cycle power plants, the next step is to work to a full decarbonization of gas turbines. This can be done either by switching to hydrogen, using other sustainable fuels such as biofuels or hydrogen derivatives (e.g. ammonia or methanol) or through Carbon Capture and Storage (CCS). All decarbonization options are described in the Whitepaper "Decarbonization Pathways for Hydrogen" by Siemens Energy [4]. This whitepaper focuses solely on hydrogen as a fuel for gas turbines.

Displacement of natural gas with sustainable hydrogen (H_2) is a viable means of enabling carbon neutral power plant operation as hydrogen combustion produces no CO_2. Additionally, blending natural gas and hydrogen can substantially lower carbon emissions and provide a steady reduction of emissions as the hydrogen portion in the fuel is continuously increased over time. For hydrogen mixtures the relationship between CO_2 reduction and hydrogen volume content is nonlinear as shown in Figure 1.

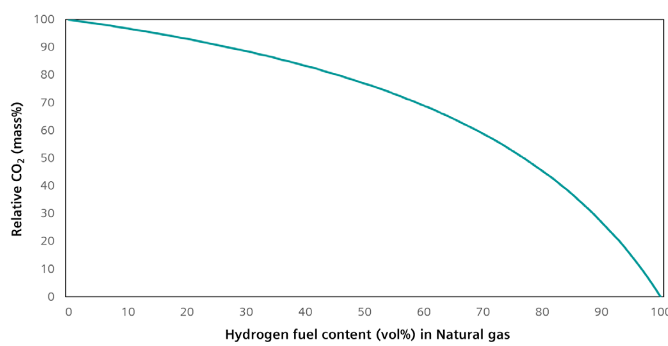

Figure 1: Relationship between hydrogen content in natural gas [volume %] and relative CO_2 emissions from the combustion process

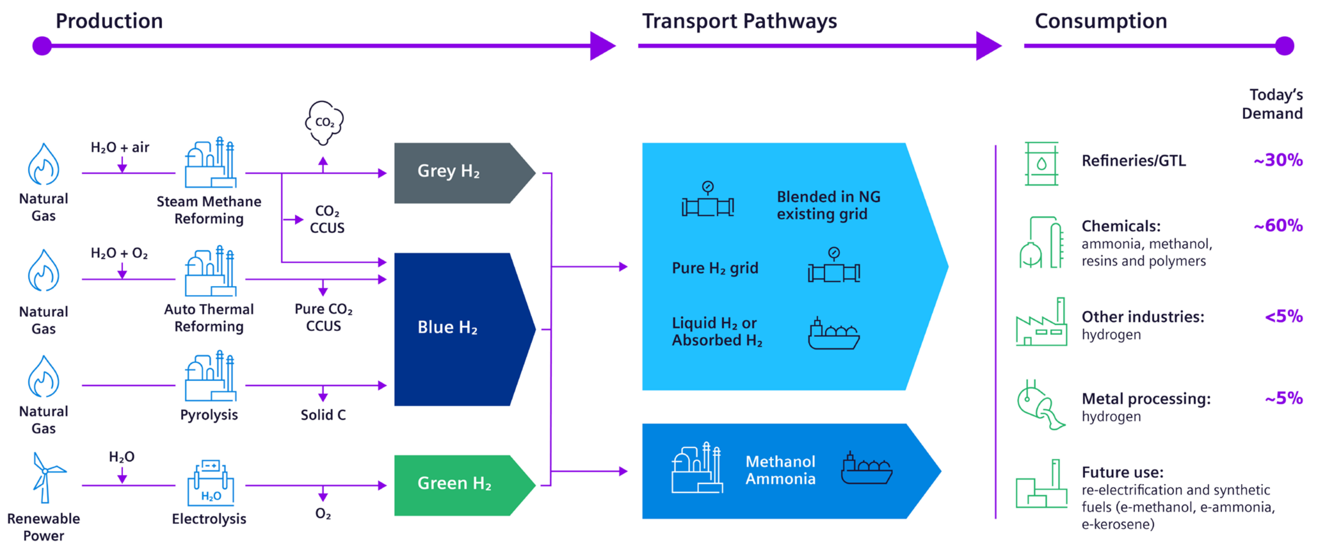

Figure 2: Production, transport and uses of hydrogen.

Substituting natural gas with hydrogen over time means that power plants remain eligible for operation even with increased CO_2 emission regulatory limits. New regulations put more stringent requirements on carbon emission from power and heat generation.

Going forward, hydrogen fueled gas turbines and combined cycle power plants will enable a fully decarbonized power system, as planned e.g. in the UK or Germany. In such decarbonized power systems renewable energy provides the backbone of all energy consumed, and the combined and simple cycle power plants provides the residual load for periods of low renewable energy production, so called "dark doldrums" (dark and wind still periods), as well as enabling large scale, seasonal storage of renewable electricity.

The hydrogen fuel blending not only lowers CO_2 emissions of gas turbines, it also ensures that the gas turbines can act as long-term electricity storage by means of hydrogen re-electrification. Hydrogen can serve as a chemical storage vehicle by being produced through electrolysis (or other processes) during times of excess renewable energy generation and then used to fuel gas turbines, converted to hydrogen derivatives or sold to other industries as shown in Figure 2.

As shown in Figure 1, to reach a 50% reduction in CO_2 emissions from the gas turbine combustion process, approximately 77vol-% hydrogen co-firing is needed. Due to the high costs of sustainable hydrogen compared with natural gas, operation of hydrogen in gas turbines is not economically competitive with natural gas today, and governmental support, carbon taxation and/or legislation is essential to accelerate the deployment of hydrogen as a fuel. Co-firing in small quantities or in a smaller gas turbine already improves the emission footprint with an acceptable economic impact. For example, adding only 10 vol% hydrogen in the fuel will reduce CO_2 emissions by 2.7%, which would result in a reduction of 30,000 metric tons of CO_2 for a reference 850 MW combined cycle power plant that runs for 6,000 hours a year at an average 60% efficiency.

The impact of hydrogen gas turbines on the power sector

In January 2019, the EU Turbines industry association members committed to developing gas turbines capable of operating on 100% hydrogen by 2030 [5]. This shows the gas turbine industry's commitment to decarbonization and will make it possible to use gas turbines for completely carbon emissions-free operation.

The use of hydrogen in gas turbines has several benefits to the power sector.

- For operators, the use of hydrogen fuels reduces the carbon emissions of existing generation plants. It allows these facilities to participate in low carbon energy markets, makes flexible and decarbonized generation capacity available and prevents stranded assets due to potential future regulations on emissions reductions.
- For the grid, gas turbines operating on hydrogen fuel or hydrogen fuel mixtures are dispatchable and make flexible and decarbonized generation capacity available. In addition to providing inertia, they also provide much needed grid ancillary services such as reactive power control, voltage control and short circuit power. Optionally, gas turbines and combined cycle power plants can be prepared to

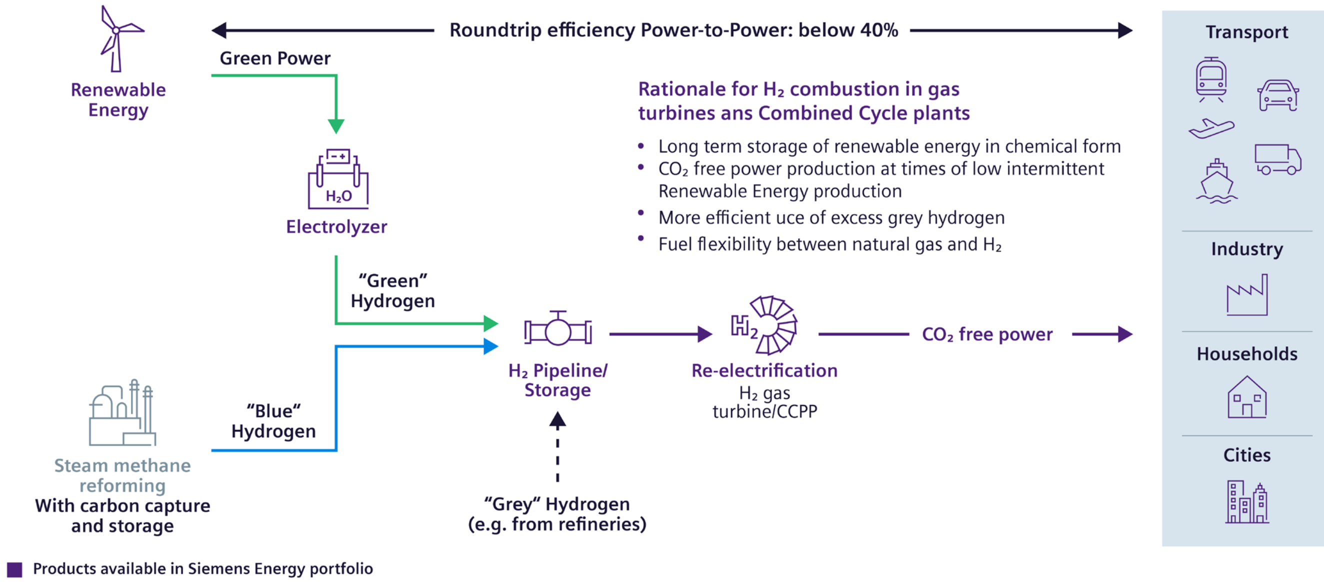

Figure 3: Sources of hydrogen generation.

be black start capable as well as to act as synchronous condenser in times where the unit is not providing active power.

- For the power sector, continuing to use the installed fleet of gas turbines avoids capital costs and CO_2 emissions associated with building new facilities to support the intermittent renewable energy market. Gas turbines in combined heat and power arrangements in various applications can provide steam and heat for industrial processes or district heating, especially as these plants will operate at times when there is a lack of renewable power, and thus also a lack of power to operate heat pumps, which will be the main technology to decarbonize lower temperature heat applications. Indeed, residual load and residual heat times are concurrent, so use of gas turbines for residual load and heat (through CHP) makes much sense.

In the IEA Net Zero 2050 scenario [6], hydrogen for electricity generation is estimated to increase to 373 TWh by 2030,1028 TWh by 2040 and 1161 TWh by 2050. This would mean according to IEA, an average blend of 5.9% hydrogen by 2030 and 87% hydrogen by 2050.

Application paths for gas turbines

There are various application paths emerging for gas turbines related to operation on 100% hydrogen or hydrogen blends mixed with other fuels, e.g. natural gas or biogas.

Renewable electricity or electricity from other zero carbon sources could be used to generate hydrogen in times of electricity oversupply, which is then stored until needed. Up to 100% hydrogen can then be burned in peaking or intermittent operation gas turbine and combined cycle power plants to provide zero or low carbon electricity and compensate for insufficient amounts of renewable electricity, thus providing sustainable residual (backup) power. Gas turbines are the optimal solution since it can provide both fast power for shorter intervals as well as operation for days, weeks and even months on stored hydrogen. In Combined Heat and Power (CHP) plants, the exhaust heat from the hydrogen combustion could be reused to a large extent to improve the energy efficiency of the hydrogen used in the re-electrification process, e.g. for district heating or process heat production.

Where does the hydrogen come from?

The source of the hydrogen should be considered when assessing its impacts on carbon emissions in power generation applications. Hydrogen production can be classified according to its carbon footprint and production method:

Green Hydrogen
Hydrogen production with zero associated CO_2 emissions, such as electrolysis using electricity from 100% renewable sources. Emerging technologies may also be classified as green if there are no CO_2 emissions associated with the electricity required for the process.

Blue Hydrogen
CO_2 capture systems are fitted to the hydrogen production technology and the CO_2 sequestered in underground aquifers or depleted oil and gas fields. CO_2 capture is not 100%

efficient, so some CO_2 will always be released to the atmosphere. This fact, coupled with typical upstream methane emissions make blue hydrogen a largely, but not 100% sustainable hydrogen. Depending on the carbon capture effectiveness, blue hydrogen reduces GHG emissions usually between 70 and 85% compared with grey hydrogen.

Grey / Black / Brown Hydrogen
Hydrogen is produced conventionally from natural gas with Steam Methane Reforming (grey), lignite (brown) or bituminous coal (black), using coal gasification. In all these cases, CO_2 is produced during the hydrogen production process and released to atmosphere. To date, more than 90% of the worldwide hydrogen is supplied via this route. Using these for power generation would generate even larger amounts of CO_2 emissions than with natural gas. However, the use of surplus hydrogen-rich flare gases from petrochemical sources, e.g. in a combined heat and power plant is economically a very attractive option already today, which increases the efficiency of the hydrogen utilization compared with a more traditional combustion in a stand-alone boiler.

Turquoise Hydrogen
Hydrogen produced through methane pyrolysis with carbon sequestration. While this is also a low carbon pathway for producing hydrogen, it is not yet commercially available.

Other Hydrogen sources
There are also additional color codes for other forms of hydrogen production:

- White hydrogen: Extracted from naturally occurring geological hydrogen reservoirs, a potentially attractive carbon-neutral (but not sustainable) source of hydrogen
- Pink hydrogen (sometimes also referred to as red or purple): Produced through electrolysis from nuclear power
- Yellow hydrogen: Produced through electrolysis from grid mix of renewables and fossil energy. Some associate this color only to solar power
- Orange hydrogen: Produced from plastic and other waste.

According to the Net Zero 2050 scenario by IEA by 2050, approximately 78% of all sustainable hydrogen produced will come from low-emissions electricity (green) and the remainder from fossil fuels with CCS (blue).

Hydrogen carriers
There are various carbon neutral hydrogen carriers suitable for storage or long-distance transport, e.g. via synthesis of ammonia and Liquid Organic Hydrogen Carriers (LOHC). Plans are being made to allow transportation of hydrogen in liquid form or via hydrogen carriers by ship to allow worldwide trading in case pipeline supply of hydrogen is technically or commercially not a viable option. According to the Hydrogen Council, the optimal carrier depends on the intended end-use, purity requirements, transport distance and the need for long-term storage [7]. The long-term optimal choice of carrier depends on a range of factors: Liquid hydrogen is most efficient if the destination requires liquid or high-purity hydrogen, and has benefits if hydrogen needs to be distributed with trucks after landing at port. This is typically the case for hydrogen refueling stations for cars or trucks. In contrast to ammonia and LOHC, liquid hydrogen does not require dehydrogenation or cracking to convert into gaseous hydrogen, which not only saves costs but also avoids purity challenges caused by carrier residues. The main drawback of liquid hydrogen is its relatively low volumetric energy density compared with ammonia, which limits the amount of hydrogen per ship, the energy required for liquefaction and the boil-off losses that occur with every day of storage. While liquefaction is a proven and commercialized technology, liquid hydrogen shipping and large-scale storage – which requires suppliers to manage the boil-off losses – remain in the early stages of deployment.

Hydrogen transport via pipelines (blended/dedicated)
Hydrogen produced from any source (green, blue or grey) can be injected into the existing natural gas network. In this case, any consumer (industrial, commercial or domestic) would be required to operate gas-fired equipment using natural gas with a hydrogen content. This may pose a challenge to many consumers and additional investment would be required to have all connected hardware able to run with hydrogen in the fuel. The hydrogen percentage could vary depending on the purity of the injected hydrogen, the injection frequency (continuous or intermittent), the complexity of the network, and the distance of the consumer from the point of injection.

While some customers of natural gas could easily adapt to consume a methane-hydrogen blend (e.g. gas turbines), other sectors may have difficulties accepting higher hydrogen blends, and some (like the chemical industry) are interested in the methane molecule itself, rather than only in the energy content of the gas. In addition, many small natural gas appliances are limited to less than 20% hydrogen content, hence requiring limiting the blending quota in varying operating conditions (both the natural gas consumption and the production of hydrogen from renewable energy show significant, frequently opposite seasonality). Such an approach will require regulators to redefine the permissible specifications for “pipeline quality” natural gas. High pressure transmission pipelines can be adapted to carry different hydrogen contents with limited retrofit requirements. While changes to valves and compression stations will be required, the pipes themselves would usually not require replacement. Unchanged, pipelines today are unlikely to exceed 25 vol% hydrogen due to concerns over leakage through seals, welds, and valves or other mechanical constraints, while several sectors will be very critical with fluctuating or hydrogen contents already over 5%.

Hence, an alternative (and more feasible option) to hydrogen blended into existing pipelines is a second, dedicated hydrogen pipeline to run in parallel to the natural gas lines, repurposed from an existing natural gas pipeline. Older gas networks built for town or city gas, e.g. old town gas pipes, can already accept hydrogen contents of up to 50%. Cross-linked polyethylene (XLPE) pipes used in low pressure natural gas distribution systems appear to be suitable for up to 100% hydrogen. In the long term, gas networks can be rebuilt to carry 100% hydrogen. The highly integrated European natural gas transmission networks represent an economically advantageous way to distribute large quantities of energy as required. The pipeline networks are available, socially accepted, and can be gradually converted to hydrogen operation with an investment of an estimated 10-15% of the cost of new construction. [8] The European Hydrogen Backbone (EHB) Initiative is planning to deploy a separate hydrogen pipeline infrastructure for 100% hydrogen through reconversion of some existing natural gas pipelines and a few new hydrogen pipeline builds. This initiative will be executed over the next decades and gradually lead to a European network that links main production sites, import terminals, underground storage caverns and main consumers of hydrogen. [9]

As different approaches (blended vs. pure hydrogen) might be used in different regions, gas turbines must therefore be able to operate in the future on any fuel gas from 100% natural gas to the maximum hydrogen content permissible on the pipeline network.

2 Hydrogen combustion

Hydrogen combustion fundamentals

Hydrogen differs from hydrocarbon fuels by its combustion characteristics, which pose unique challenges for gas turbine combustion systems designed primarily for natural gas fuels. Flame temperatures for hydrogen under adiabatic and stoichiometric conditions are almost 300 °C higher than for methane. Hydrogen's laminar flame speed is up to 8 times that of methane and the auto-ignition delay time of hydrogen is more than three times lower than methane, as shown in Figure 4 for flame temperatures of 1600 °C and gas turbine conditions. With these characteristics hydrogen is a highly reactive fuel and controlling the flame to maintain the integrity of the combustion system and reach the desired level of emissions is a formidable challenge for research and development teams.

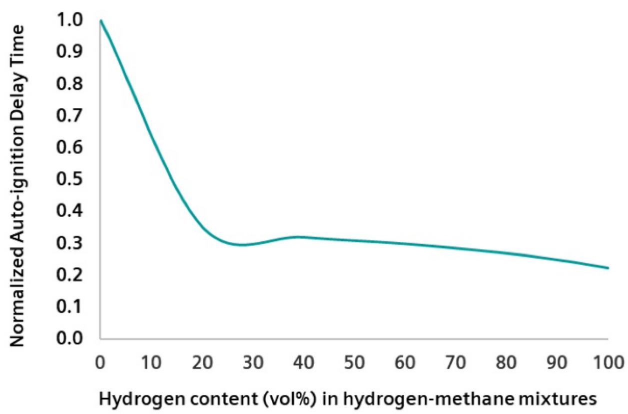

Figure 4: Hydrogen's impact on auto-ignition delay for hydrogen-methane mixtures.

Dry Low Emission (DLE) combustion technology

In dry low emissions combustion systems, fuel and air are mixed prior to combustion in order to precisely control flame temperature which, in turn, allows the control of the rates of chemical processes that produce emissions such as nitrogen oxides (NO_x). The relative proportions of fuel and air is one of the driving factors for NO_x but also for flame stability. Hydrogen's higher reactivity poses specific challenges for the mixing technology in DLE systems:

- Higher flame speed with hydrogen increases the risk of the flame burning closer to the injection points, travelling back into mixing passages, or burning too close to liner walls leading to damage (see example in Figure 5). This risk increases as the hydrogen content in the fuel is increased and with increasing combustion inlet and flame temperature
- Hydrogen's lower auto-ignition delay compared to methane increases the likelihood of igniting the fuel in the mixing passages leading to damage
- Changes to thermoacoustic noise patterns because of the different flame heat release distribution can affect combustion stability and reduce the life of combustion system components.

Siemens Energy DLE combustion systems generally use swirl stabilized flames combined with lean premixing to achieve low NO_x emissions without dilution of the fuel. The acceptable fuel fraction of hydrogen depends on the specific combustion system design and engine operating conditions. Hardware and control system changes are required for higher safety, meet NO_x emission limits and manage varying fuel compositions. Siemens Energy is in the process of extending the hydrogen capability of its DLE systems, with more details provided in the following sections.

As hydrogen capabilities are still under development for the different turbine families, some operational restrictions may be required at high hydrogen contents. These may include derating, the use of a conventional fuel for startup and shutdown, and higher NO_x emission levels which may require the need for post-combustion emission control like Selective Catalytic Reduction (SCR) systems. In the long term, we envisage performance levels with hydrogen combustion comparable to natural gas operation.

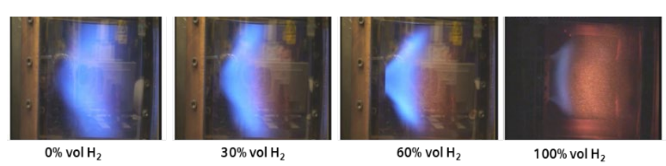

Figure 5: Flame position changes with increasing hydrogen fuel content, showing the most compact flame at 100% hydrogen. Also note how the 100% hydrogen flame is not as luminous as the natural gas flame [10].

Non-DLE combustion technology

Non-DLE technology uses diffusion flames or partially premixed flames. There are several advantages and disadvantages associated with non-DLE systems:

- In general, these systems handle a large envelope of fuel compositions, and 100% hydrogen is possible on various Siemens Energy non-DLE gas turbines
- Diffusion flames require dilution to control NO_x emissions, which are driven by high flame temperatures. Hydrogen has higher flame temperatures compared to natural gas, which means NO_x emission will be higher without abatement. Dilution is achieved by the introduction of nitrogen (N_2), steam, or water into the flame:
    - Nitrogen dilution has the advantage of being available at the plant as a cracking product in cases of ammonia cracking. Using the nitrogen produced as a byproduct to dilute the fuel reduces plant operating costs.
    - Steam dilution is significantly more efficient than nitrogen dilution in terms of emission reduction and in combined cycle or Combined Heat and Power (CHP) configurations steam dilution has a relatively small plant efficiency impact.
    - Injection of water into the combustor reduces the combustion flame temperature, thereby reducing NO_x and has the added benefit of boosting power output of the gas turbine.

High costs and increased turbine maintenance associated with dilution due to the injection of nitrogen or demineralized water make diffusion flames with this abatement technology rather unattractive.

- For single shaft gas turbines, surge margin can be a challenge with diluted high-hydrogen fuels due to changes in the balance of volumetric flow between the compressor and turbine. This can be managed by compressor and / or turbine modifications.

NO_x emission correction when burning hydrogen rich fuels

When burning hydrogen rich fuels, attention needs to be placed on the emission limit calculation methodology, which leads to a different range of values compared with conventional fuels.

Today, most emission limit regulations are defining NO_x emissions as a relative concentration of NO_x in the exhaust gas of the turbine, e.g. as ppmv or mg/Nm^3, but always referenced to 15% O_2 content in the exhaust gas and to dry exhaust conditions. This calculation method was selected for ease and consistency of measurement across different turbines excess air and operational profiles.

With hydrogen as a fuel, this leads to a double change of the correction factor: On one hand, there is more water vapour in the exhaust gas, so normalizing to dry exhaust conditions increases the ppm number. Similarly, combusting H_2 leads to a reduced consumption of oxygen, which again requires a larger correction factor increasing the ppm value. At 100% H_2, these effects lead to numerically overinflated NO_x emissions by 37.2% (see Figure 6). These effects need to be taken into account when setting new NO_x emission limits or when comparing emissions between different fuels.

As a solution to this calculation bias, it is recommended to adapt the measurement unit to neutralize the emission bias of the fuel. This can be done either via a fuel correction factor or via a switch from a volumetric to a mass specific measurement unit, e.g. mg per energy unit (consumed or produced). A potential variation of the hydrogen content in the fuel over time also needs to be taken into account.

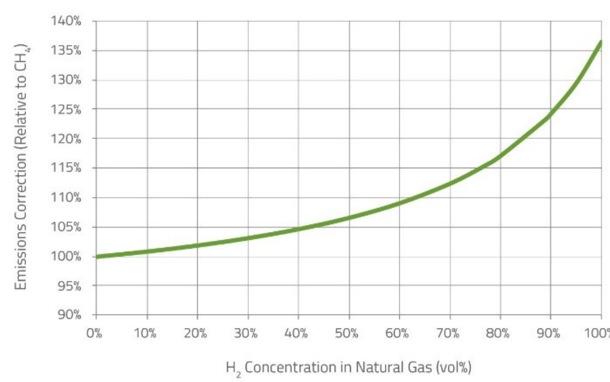

Figure 6: Energy-based emissions correction factor for increasing hydrogen content in natural gas as a factor of the blending rate

3 Hydrogen capabilities in Siemens Energy gas turbines

Siemens Energy gas turbine hydrogen operating experience

Siemens Energy fleet experience with high hydrogen content fuels is extensive, with more than 55 units around the world amassing more than 2.5 million operating hours since the 1960s. High hydrogen gas turbine applications have been built for a range of industries and span the power range of the Siemens Energy gas turbine portfolio. Experience has been gained on unabated diffusion flame, Wet Low Emissions (WLE), and Dry Low Emissions (DLE) combustion technologies. Although many of these references are based on hydrogen-rich synfuels, which offer a different combustion behavior compared with a natural gas-hydrogen fuel mixture, Siemens Energy has gained a high level of experience in managing hydrogen on a plant level and within their gas turbine systems (see Figure 7).

Siemens Energy gas turbines can operate on high percentages of hydrogen fuel, with the specific capability of a unit depending on the gas turbine model and the type of combustion system. See Figure 8 for the high-hydrogen options across the portfolio for new unit applications that are available on specific request. For already installed units the current capabilities are given in the gas turbine manual. Higher hydrogen mixtures for those existing power plants and options for upgrading are discussed in Section 5.

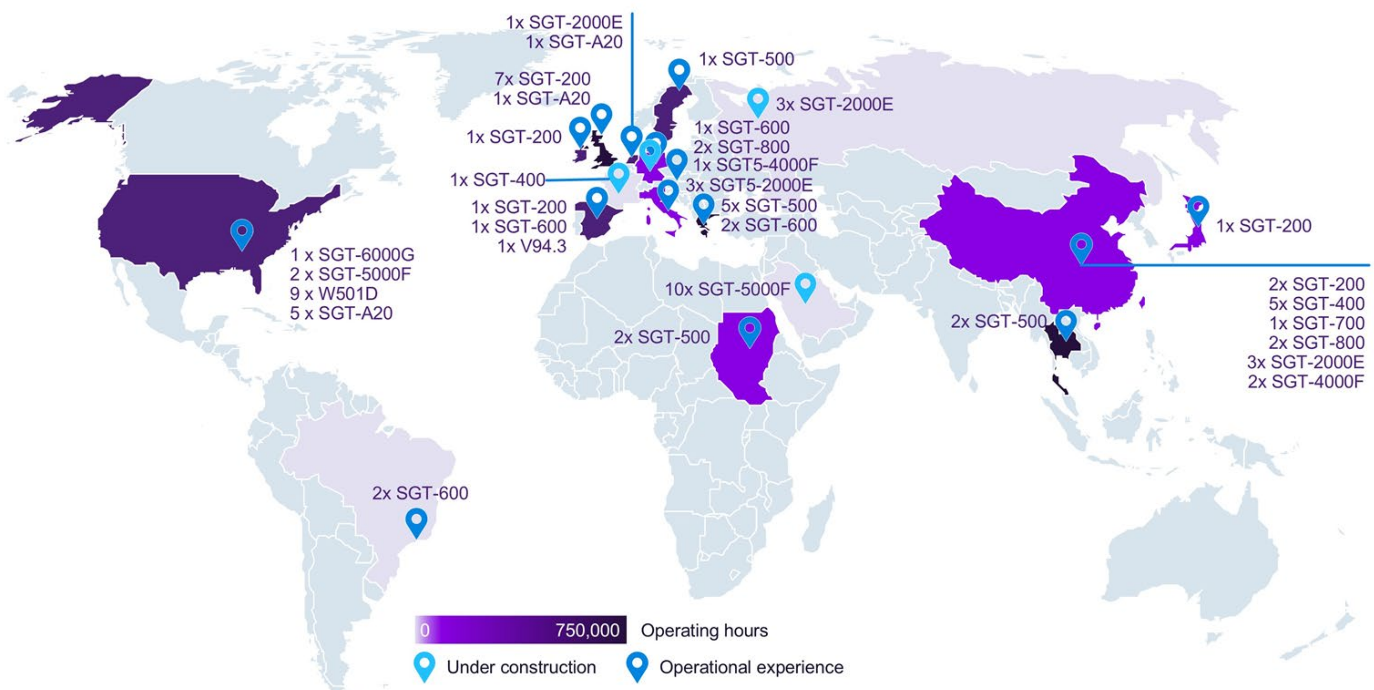

Figure 7: Siemens Energy's high hydrogen fleet experience.

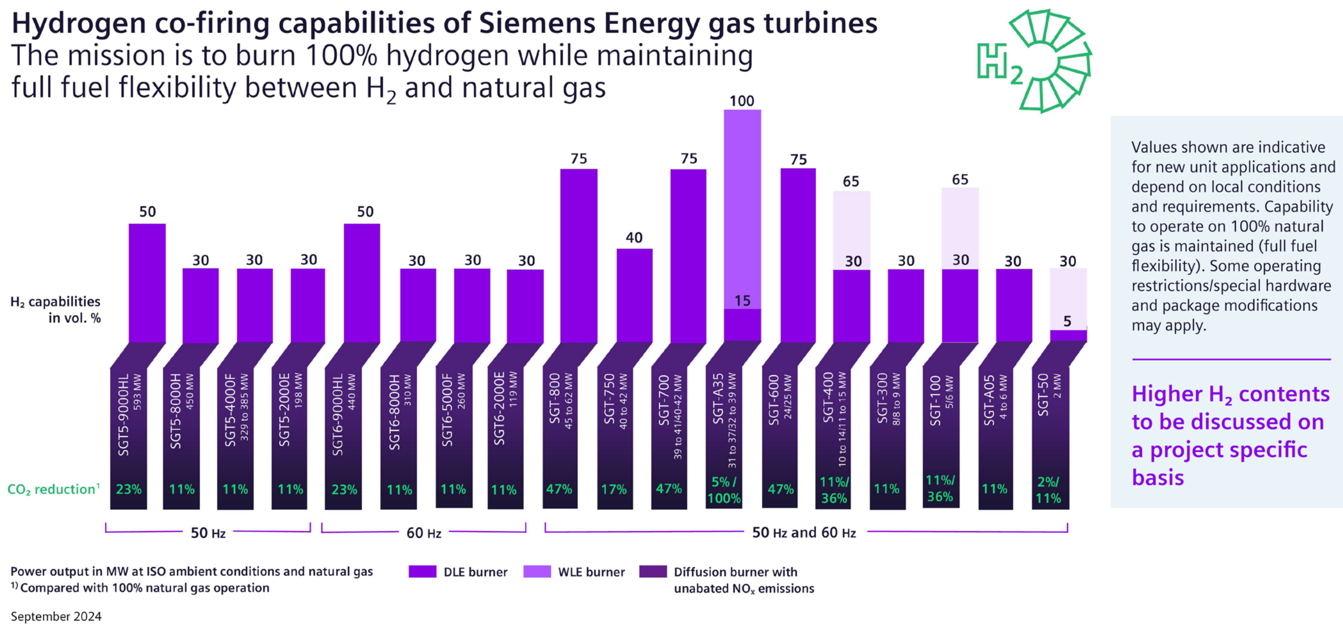

Figure 8: Siemens gas turbine portfolio hydrogen co-firing capability for new unit applications. Retrofit capabilities of existing units may vary due to unique site constraints, combustion systems, implementation timing and other factors.

Detailed information on GT families

Large gas turbines

DLE technology
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 synthetic gas (syngas) to the gas turbine. These Carbon Capture and Storage (CCS) syngases 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 and 2010s with governmental support (EU, United States Department of Energy (US DOE) [11], and German Federal Ministry for Economic Affairs and Energy (BMWi) [12]). 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 fuels has contributed to the development of future pure hydrogen capable DLE technology.

Siemens Energy 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 is capable to run on up to 50 vol% hydrogen. By 2030, commitments by Siemens Energy ask for the commercial availability of large gas turbines capable of running on 100% hydrogen in DLE mode.

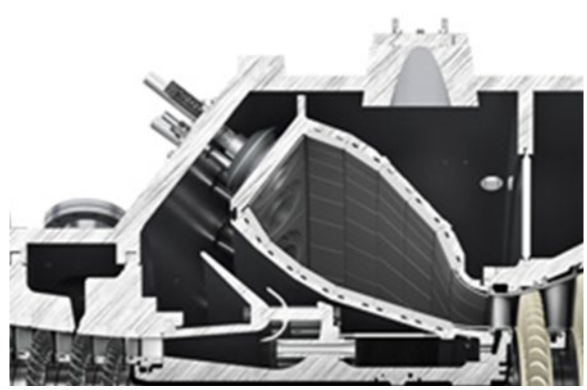

Figure 9: SGT-4000F annular combustion chamber.

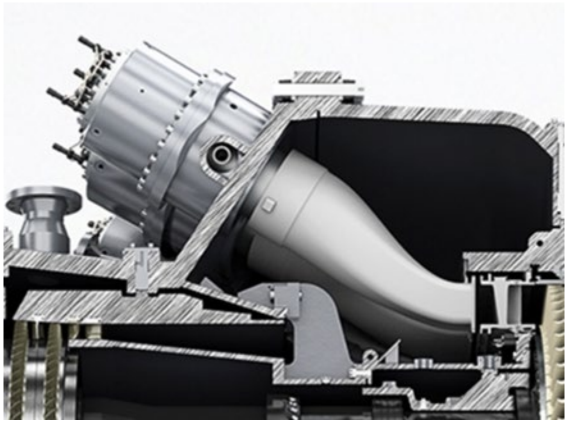

Figure 10: SGT-5000F combustion system.

In 2022, two Siemens Energy SGT5-2000E utility scale gas turbines were commissioned to run commercially on a 27.2% H_2 content in the fuel with DLE technology. The power plant operates on a hydrogen-rich refinery offgas, providing Combined Heat and Power (CHP) in baseload mode to the adjacent refinery. This hydrogen cofiring 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 operations on natural gas and with the hydrogen fuel mixture.

In December 2024, UK energy company SSE Thermal and Siemens Energy announced an accelerated hydrogen power partnership, launching "Mission H_2 Power" – a collaboration which aims to deliver gas turbine technology capable of running on 100% hydrogen, fuelling the transition to net zero and potentially boosting the UK's energy security. The project builds on the existing partnership between SSE and Siemens Energy. It supports the decarbonisation of SSE's Keadby 2 Power Station in North Lincolnshire, which is powered by a Siemens Energy's SGT5-9000HL gas turbine.

Under the co-investment, Siemens Energy will develop a combustion system for its SGT5-9000HL gas turbine capable of operating on 100% hydrogen, while maintaining the flexibility to operate with natural gas and any blend of the two. This will see additional facilities constructed at Siemens Energy's Clean Energy Centre in Berlin to allow testing of the technology for large gas turbines to take place [13].

No -DLE Technology
Since the early 1990s, Siemens Energy has gained experience operating some of 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) [14]. These syngases are mixtures of varying composition, but typically have significant fractions of hydrogen and CO, as well as inert gases (N_2, CO_2, steam). In general, Siemens Energy is focusing its hydrogen R&D on DLE technology only. Other forms of NO_x abatement such as WLE are not being developed due to their very high water consumption and operating costs.

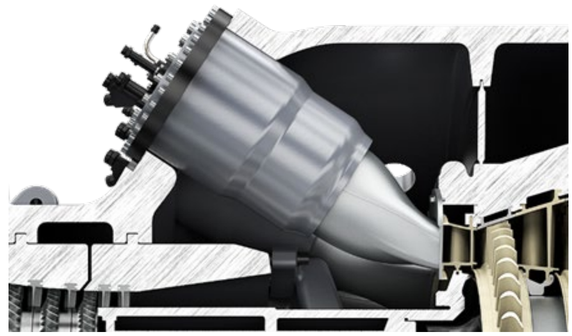

Figure 11: SGT5/6-9000HL combustion system.

Medium industrial gas turbines

DLE technology

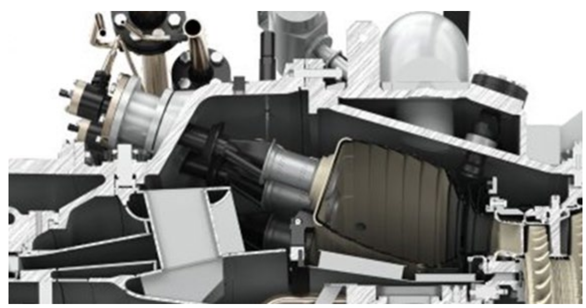

Figure 12: 3rd generation DLE combustion system.

The SGT-600, 700 and 800 use 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 three years has cleared 75 vol% hydrogen on the SGT-600, SGT-700 and on the SGT-800. The SGT-600 has operated up to 88 vol% of hydrogen in a commercial environment, and a variant of the 3rd generation DLE burner, that is used in all three engines, has been tested at the Siemens Energy Clean Energy Center in Berlin with up to 100% hydrogen fuel at engine-like conditions. This significant achievement was enabled by additive manufacturing which allowed for more efficient combustion system aerodynamics. Continued engine testing isplanned going forward with the target to reach 100% hydrogen capability in near term.

The SGT-750 engine is equipped with the 4th generation DLE burner. The 4th generation burner has a central premixed pilot with radial main swirler, contrasting it from the HR3 burner which uses a diagonal 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 [15].

Siemens Energy has sold two SGT-600 for the Braskem refinery in Brazil, with capability to operate on 60 vol% hydrogen in DLE combustion mode keeping NO_x emissions controlled to 25ppmv. This power plant started operation in 2021 under an Operation & Maintenance contract where Siemens Energy takes responsibility for delivery of power and heat to the adjacent refinery with reliability and availability guarantees. Since then, the units have been operating in baseload operation with average hydrogen blends of around 60 vol% and a maximum of 88 vol%.

Non-DLE technology
Siemens Energy 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.

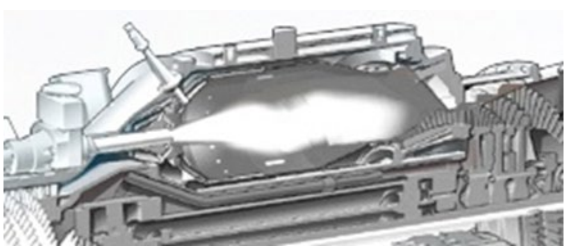

Figure 13: SGT-500 Non-DLE combustion system.

Aeroderivative gas turbines

DLE technology
The Siemens Energy aero-derivative engines, like the SGT-A35 (see Figure 14), 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 powers and conditions and to minimize thermoacoustics as the heat release profile through the combustor can be varied for a given constant power. The SGT-A35 combustion system has the capability to run with up to 15 vol% hydrogen today, and the A05 is capable of 30%.

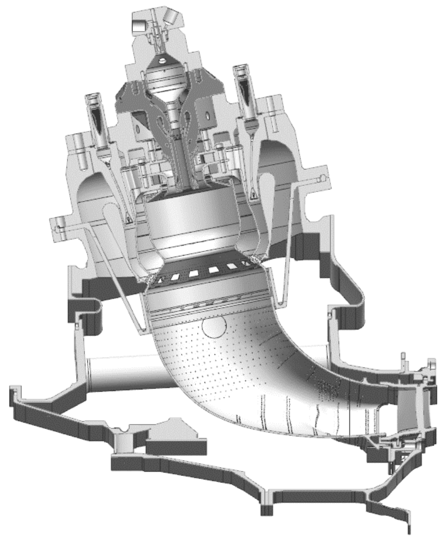

Figure 14: SGT-A35 DLE combustion system.

Non-DLE technology
Non-DLE systems in the Siemens Energy 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-A35 uses the Phase II combustion system and is capable of operating on 100% hydrogen. 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.

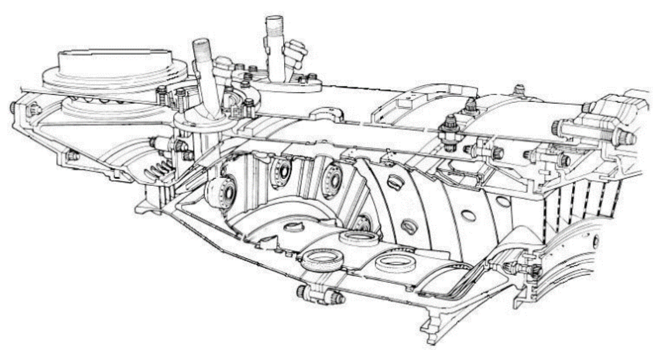

Figure 15: SGT-A35 Non-DLE combustion system.

Small industrial gas turbines

DLE technology
Siemens Energy 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 can burn mixtures of hydrogen and methane up to 30 vol% on the SGT-100, -300 and -400, which is being further developed for increased hydrogen fractions through the Siemens Energy hydrogen roadmap. The SGT-400 has been selected as the technology proving platform for the new hydrogen DLE burner system, and in September 2023 has already demonstrated 100% DLE operation with hydrogen at the HYFLEXPOWER project in France [16]. Details of this project are shown under an own chapter in this section. Latest by 2030, commercial availability of 100% hydrogen operation in DLE mode for first small industrial gas turbines is targeted.

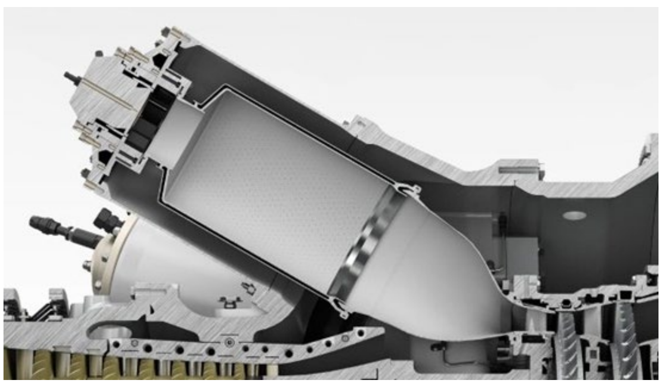

Figure 16: SGT-400 DLE combustion system.

Non-DLE technology
The SGT-200 and SGT-400 with non-DLE combustion systems have more than one 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% with more than 800,000 operating hours.

Technology enablers and Siemens Energy roadmap toward 100% hydrogen gas turbines

Siemens Energy is employing several key technology enablers to further develop the hydrogen capability of its gas turbines.

High fidelity Computational Fluid Dynamics (CFD)
Advanced CFD tools allow Siemens Energy 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 17. 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 increasing share of hydrogen, thermo-acoustics of the flame changes as explained in Section 2. To account for this effect, Siemens Energy is engaged with universities to implement the latest advances from the research community into their tool suite and to take those effects into account during early stages of the design process.

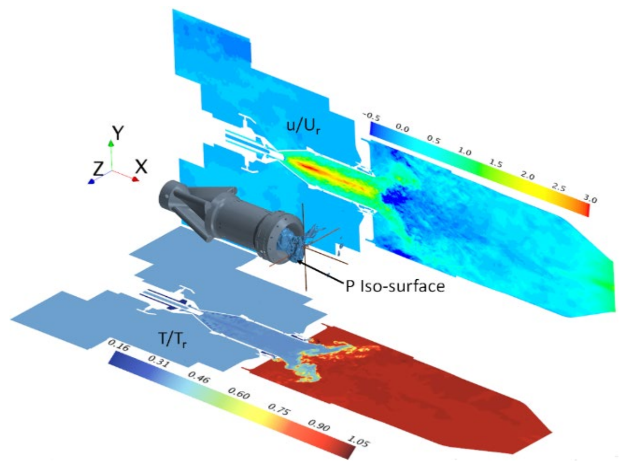

Figure 17: CFD flow field overview from a study of SGT-800 3rd generation burner with high-hydrogen fuels [17].

Additive manufacturing
Siemens Energy's additive manufacturing capability enables the integration of innovative design features and allows technology validation time to be accelerated by up to 75%. Siemens Energy has built up an additive manufacturing (AM) business to establish prototype and serial manufacturing capability. Over the recent years tremendous efforts have been made in the fields of materials and processes, industrialization, and design for function. Materials such as IN 625 and Hastelloy X have been fully characterized to enable designers to utilize the benefits of AM. Moreover, the productivity of the respective processes was significantly improved via increased layer thicknesses and transfer to industrial multi-laser machines. Key, however, is the integration of AM in a bigger scale production landscape including de-powdering, removal of supports, heat treatment, and respective quality control. Today a global fleet of more than 50 laser-powder bed machines produces metal parts for Siemens Energy gas turbines in their production facilities located in Orlando, Florida, USA, Worcester, United Kingdom and Finspång, Sweden. Figure 18 shows final AM built premixed combustion swirlers for heavy-duty large gas turbines.

Figure 18: Additive manufactured premixed combustion swirlers for heavy-duty large gas turbines.

This enables a faster response to changing customer needs. As shown in Figure 19, additive manufacturing is supporting the development of combustion technology that can overcome the challenges of hydrogen applications. It enables the creation of complex cooling features and fuel routing that would not previously have been possible with conventional manufacturing techniques. These features are vital when it comes to ensuring stable combustion of hydrogen.

Figure 19: Fuel burner design progressions from welded (top left) to SLM additive manufacturing (bottom right) for 3rd generation DLE burner.

High pressure combustion testing
Despite all the advances that were made in past years in the area of CFD, combustion today is still a complex field that cannot be modelled with theoretical models alone. Testing the combustion systems at engine pressure and temperature conditions is therefore still an important part of the Siemens Energy design process. All new developments undergo rigorous testing to ensure safe operation at the customer site. The Clean Energy Center in Berlin is Siemens Energy's facility for high pressure (35 bar) combustion tests, shown in Figure 20. The facility supports testing of components and systems for the entire 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 support of the increased demand for hydrogen applications. In the next years, the hydrogen capability of the CEC near Berlin is to be expanded to allow for increased number and volume flows of testing. With this in-house capability, Siemens Energy ensures new knowledge is shared across their fleet and timely support is provided to customer projects for special fuels like hydrogen.

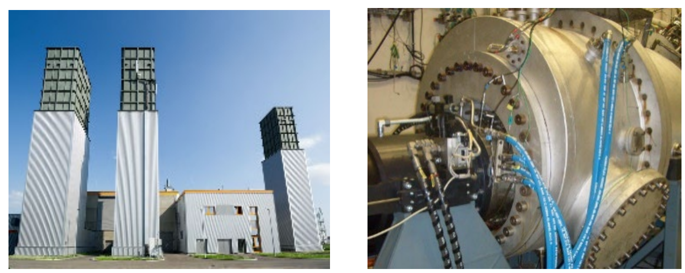

Figure 20: Clean Energy Center facilities for high pressure combustion tests, Berlin, Germany.

The HYFLEXPOWER Project – Technology for Deep Decarbonization with 100% Hydrogen Power-X-Power
Siemens Energy committed to advancing technology through a building block strategy aimed at developing hydrogen-natural gas flexible combustion systems across its gas turbine product range. This approach involved creating a set of core technology elements that could be universally applied within the product portfolio.
The innovative technology was developed and initially demonstrated in an existing SGT-400 based cogeneration facility in Saillat-sur-Vienne, France (Figure 22) within the EU-funded HYFLEXPOWER project. In 2020, a Siemens Energy-led consortium including ENGIE, Centrax, Arttic, German Aerospace Center (DLR) and four European universities, at the Smurfit Westrock paper recycling plant, launched the implementation of HYFLEXPOWER, the world's first industrial power-to-X-to-power demonstrator with an advanced H_2 gas turbine. The integrated hydrogen project as shown in Figure 21 demonstrated that an existing industrial Combined Heat and Power (CHP) plant can be upgraded for production of green hydrogen from renewable energy in an electrolysis facility, hydrogen compression and storage and its further re-electrification. For this, the existing SGT-400 industrial gas turbine was upgraded to allow for combustion of stored

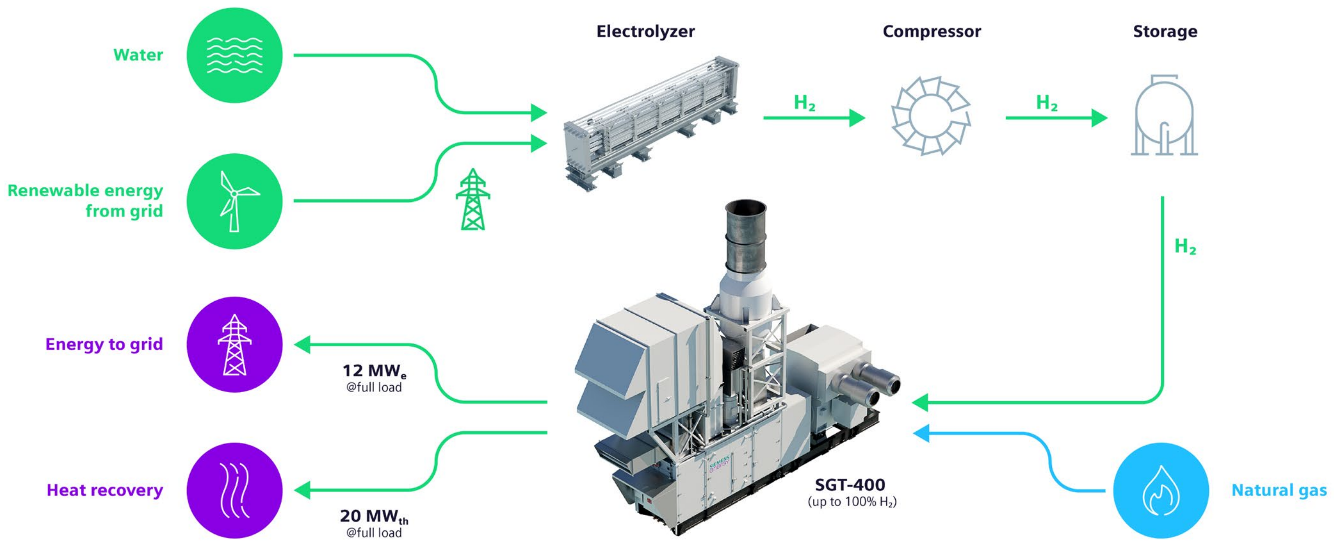

Figure 21: Schematic of EU funded HYFLEXPOWER Project.

green hydrogen into electricity and thermal energy. During two demonstration campaigns in 2022 and 2023, the facility demonstrated for the first time a flexible operation with natural gas-hydrogen fuel mixtures from 100% natural gas to 100% H_2 in DLE operation mode enabling CO_2-free power and heat generation with green hydrogen.
By taking this approach, the overall development timeline and cost of the 100% H_2 DLE combustion technology for the GT portfolio was minimized. Additionally, the risk for the higher firing temperature gas turbines will be mitigated by first validating the technology elements in smaller, lower firing temperature gas turbines.

The HyCoFlex Project
In 2024, the EU and UK-funded HyCoFlex project was launched at the same industrial cogeneration site as the HYFLEXPOWER project, building on its foundational achievements. Led by Siemens Energy, the HyCoFlex consortium aims to advance the power-to-hydrogen-to-power plant for combined heat and power (CHP) applications, with a focus on enabling gas turbines to operate flexibly on up to 100% hydrogen. The project is set to demonstrate the technology through site testing in 2025 and 2026, validating the commercialization potential of the SGT-400 DLE hydrogen gas turbine.
HyCoFlex seeks to optimize the hydrogen technology to enhance efficiency, emissions control, and operational flexibility in industrial cogeneration plants. By refining existing infrastructure and developing tailored operational strategies, the initiative aims to address the dynamic needs of these facilities. New design enhancements will push the turbine's firing temperature to its limits while ensuring compliance with NO_x emission targets, thereby establishing a robust foundation for commercialization. Through these advancements, HyCoFlex aspires to improve the performance and reliability of hydrogen-fired gas turbines and contribute to the broader goal of decarbonizing the energy sector while promoting sustainable industrial practices.

Figure 22: Smurfit Westrock SGT-400 Cogeneration plant in Saillat-sur-Vienne, France.

Siemens Energy Zero Emission Hydrogen Turbine Center
Siemen Energy has developed a demonstration plant at their gas turbine manufacturing facility in Finspång, Sweden, to show how hydrogen and gas turbines, renewable energy production and energy storage work together in a future flexible and sustainable energy system. Excess energy from gas turbine tests and electricity from solar panels are used to produce hydrogen in an electrolyzer. The hydrogen is stored and used later as a fuel for gas turbine testing. In the local microgrid created, it will be possible to optimize the use of energy through storage as hydrogen and/or in batteries. Hydrogen produced in the plant will also enable continued research and development to optimize the use of hydrogen in gas

turbines and reach Siemens Energy's goal to run gas turbines on 100% hydrogen contributing to a full decarbonization of the power sector.
The project was developed in the framework of Era Net Smart Energy Systems with support from the European Union's Horizon 2020 research and innovation program and the Swedish Energy Agency. [18]

Figure 23: Siemens Energy's Zero Emission Hydrogen Turbine Center.

Hydrogen roadmap for Siemens Energy gas turbines
The 100% hydrogen gas turbine program 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. Siemens Energy is making significant strides in the development of 100% hydrogen-fueled gas turbines with DLE technology, in order to have the first frames commercially available latest by 2030. To achieve this target, they are continuously developing the necessary technologies and implementing these new designs into the product portfolio.

Summary

Over the last few decades, hydrogen capability in the Siemens Energy gas turbine portfolio has been developed to meet customer and project demands. These demands have differed significantly across the portfolio and the proven capabilities clearly reflect this. The higher capabilities, for example in the industrial gas turbine portfolio, were driven by demand from the industrial and petrochemical sector. We now see demand rising in the energy sector for high-hydrogen capabilities due to the drive toward energy decarbonization. Siemens Energy is answering this demand with a development roadmap as shown in Figure 24.

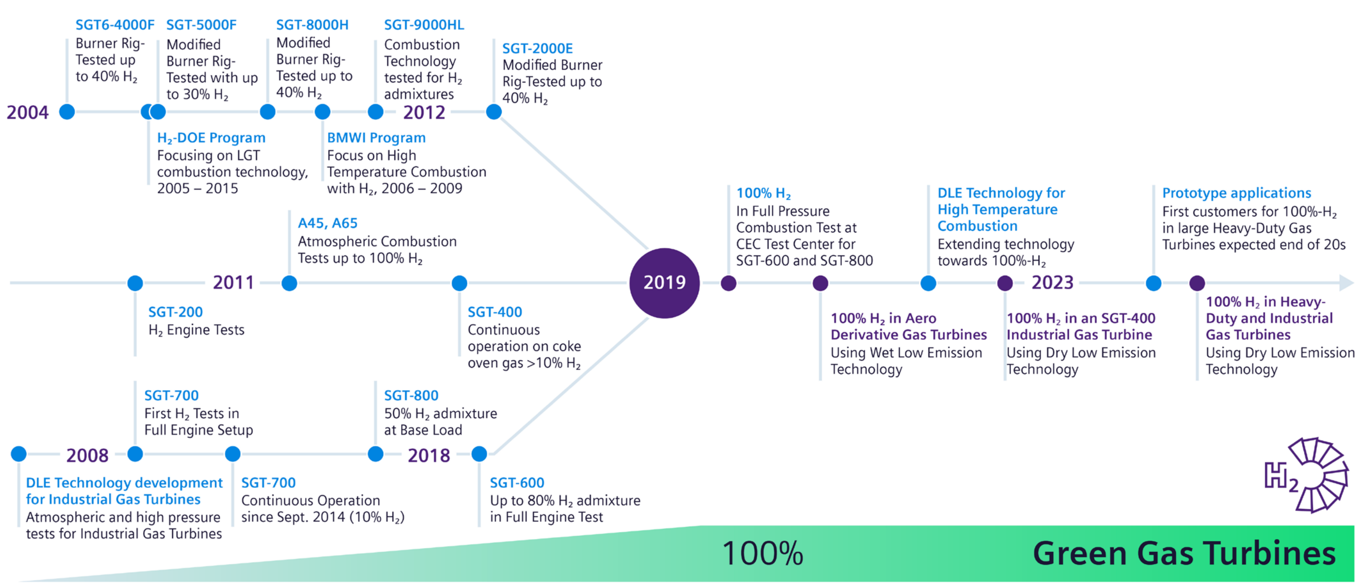

Figure 24: Siemens Energy 100% hydrogen gas turbine roadmap.

4 Hydrogen capabilities of power plant systems

Additional systems required for hydrogen co-firing

Hydrogen operation capability in power plants has additional requirements on the systems and components upstream and downstream of the gas turbine.

In case of supply of a blended hydrogen/natural gas mixture, all components in the fuel gas system upstream of the gas turbine need to be designed for hydrogen compatibility. Depending on blending ratio, temperature and pressure, this could affect components in different systems such as pipes, valves, filters/strainers, preheaters, measuring devices and transmitters.

Additional gas conditioning systems are required when there is a separate hydrogen supply to the plant. In addition to the requirements mentioned above in the fuel gas supply system, a hydrogen and natural gas mixing station with valves, gas composition and flow measurement would be required and also the gas supply pressure would need to be slightly increased. Siemens Energy has designed an optimized mixing station for such applications.

Power plant component considerations for hydrogen co-firing

Gas fuel supply system:
Because the fuel gas system is handling the hydrogen directly, the necessary hydrogen resistance needs to be confirmed for the implemented components and materials. Furthermore, adapted requirements on pressure, flow and temperature to the gas turbine need to be considered in the design of the gas fuel supply system, possibly requiring increased pipe diameters to accommodate the increased fuel volume flow when burning hydrogen.

Heat Recovery Steam Generator (HRSG):
Downstream of the gas turbine the influence of hydrogen co-firing is smaller than upstream, but some mitigation may need to be taken. Compared to natural gas firing, the HRSG must handle exhaust gases with different compositions, volume flows and in some cases changes to the exhaust temperature. In addition, provisions for ventilation may be required in cases of unburned hydrogen entering the HRSG, e.g., after a failed start or a flame-out event. In case of a supplementary firing system, additional aspects such as the flue gas characteristics need to be investigated.

Selective Catalytic Reduction (SCR) system:
Due to the increased NO_x emissions associated with burning hydrogen, the provision of a Selective Catalytic Reduction (SCR) System may become larger or necessary depending on the applying local emission regulations. If a SCR may be required at a later stage when increasing the hydrogen content over the years, sufficient space in the HRSG needs to be provided for a later retrofit.

Buildings and Ventilation:
Due to the different density and flammability characteristics of hydrogen, the definition of the hazardous areas in the power plant needs to be revisited. Special consideration must be taken on the active and passive ventilation of the buildings to handle any leakage of hydrogen and the installation of suitable gas detectors to detect such leakages.

Electrical Equipment:
Electrical systems in areas susceptible to hydrogen presence will require a gas group classification according to IEC Group IIC - in NFPA regions alternatively NEC 500 Class I Div 2 Group B (explosion proof protection).

Power plant performance:
Due to the different physical properties of hydrogen compared to natural gas, the following effects on power plant performance will need further consideration/adaptation in detail: NO_x emission handling, introductory ratings, design back pressure drop, fuel gas preheating, combustion stability and dew point in the cold end of the HRSG/stack.

Hydrogen readiness for new gas turbine-based power plants

In the next years, newly built gas power plants will mainly run on natural gas, due to the already significant GHG reduction when using natural gas compared with other dispatchable fuels (e.g. coal) and the unavailability of large amounts of hydrogen as fuel. However, new power plants being built today will very likely be required to be converted at a later stage to burn a blend of hydrogen up to 100% during the lifetime of the plant, hence requiring provisions for cost-efficient later retrofit for hydrogen operation.

This demands hydrogen-ready power plant solutions with a prepared pathway up to 100% hydrogen capability. In this case the power plant is designed to be converted to hydrogen operations at a later stage. A new power plant can also be designed and build to operate with a defined share of hydrogen without any technical modification ("H_2 Capability"). In that way the power plant is already hydrogen capable, according to the limits of the current capabilities of the respective gas turbine. However, today's new power plants will typically start operating with natural gas for a number of years. It is therefore crucial to have the option of new natural gas fired power plants solutions that can easily be upgraded and converted to hydrogen operations as hydrogen becomes available to the operator. By doing so, natural gas fired power plants are future-proof and will be fit to meet the amount of hydrogen for which it has been made ready, with minimal conversion costs ("H_2 Readiness"). The efforts to upgrade these power plants may vary for each power plant, as they are built according to specific requirements agreed between the plant operators and the technology providers.

Hydrogen-readiness power plant concept certification
Siemens Energy is the first company worldwide to have received a third-party certification for its "H_2-Ready" power plant concept.

Depending on the required roadmap of hydrogen co-firing requirements over time, Hydrogen-readiness allows the design of power plants that enable a later retrofit to hydrogen co-firing with minimal costs and disruptions, while keeping the additional front-end investment limited. The detailed configuration of a hydrogen-ready plant will always be determined project-specific in line with the expected hydrogen co-firing roadmap for the plant.

Figure 25: Hydrogen ready power plant concept certification

The independent Certification Guideline for H_2-Readiness of Combined Cycle Power Plants, provided by international certification provider TÜV SÜD, covers the three phases in the life cycle of the plant:

1. Bidding Phase - when the concept of the hydrogen-Readiness is established according to the client's H_2-roadmap (Concept Certificate - Generic).
2. Project Phase – when the concept is implemented into the design and construction of a H_2-Ready power plant (Project Certificate – Project specific).
3. Transition Phase – when the plant is converted into a H_2 fired plant, once hydrogen is available (Transition Certificate – Project specific).

The "H_2-Ready" concept certificate provides a roadmap describing how a new power plant can be converted over time to co-fire hydrogen or even burn pure hydrogen, limiting future conversion cost and making the power plant future-proof. The certificate was awarded through the analysis of an SCC-800 combined cycle power plant which was designed H_2-ready according to the certification guideline. Except for the gas turbine and associated package, the concept may also be used for other gas turbine plant configurations. On a project specific case, the certification process can be further expanded with "H_2-Ready"- certificates for the plant specific construction (Project Certificate) and retrofit phases (Transition Certificate).

Hydrogen-readiness categorization for new gas turbine power plants according to EU Turbines
Under the framework of the EU Turbines Association in which Siemens Energy is a member, key gas turbine manufacturers in the power plant industry will voluntarily indicate with each newly built power plant a specific category of hydrogen-readiness fulfilled by the power plant [19].

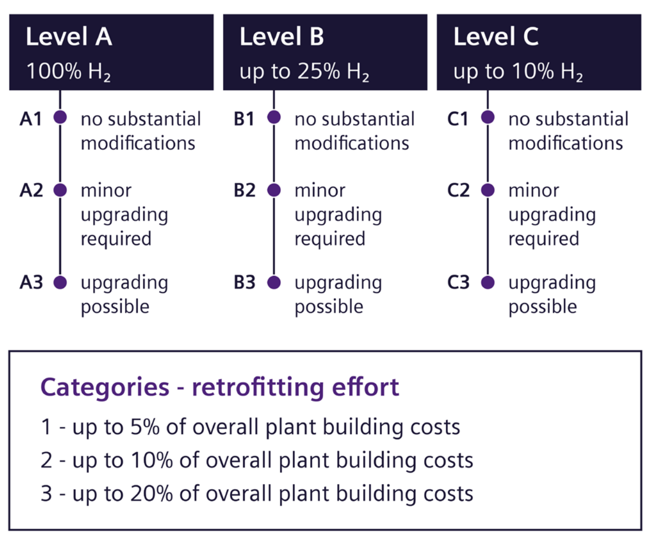

Figure 26: Hydrogen readiness levels and retrofitting effort categorization as defined by the EU Turbine Association [18].

At this moment first countries are in the process of implementing a dedicated H_2 pipeline infrastructure with first pipelines becoming operational in Germany and Netherlands in 2025 and a first European hydrogen backbone in 2030. [9] As hydrogen will remain a scarce resource over the next decade, the most likely scenario is that a limited number of hydrogen valleys and a backbone grid connecting these valleys and large-scale generation facilities will be available. These regions and hydrogen pipelines will be extended in the future. In the remaining gas grid, especially the distribution grid, we may see a blending of hydrogen into the existing natural gas grid, but most indications point towards complete separate hydrogen and natural gas networks. In such a case, if a power plant requires a specific hydrogen blend, it will require connection to both networks and a local mixing station. The maximum blending share in pipelines is expected to remain to max. 5-20% by volume - if blending is accepted at all.

Accordingly, the EU Turbines Association defines three levels of readiness according to the hydrogen content of the gas used combined with a categorization of required retrofitting effort as shown in Figure 26. Current market trands indicate that most power plant operators interested in a later switch to hydrogen plan for a 100% H_2 readiness.

CertaLink™ - Clean Energy Certification
Beyond the scope of hydrogen and new power plants, Siemens Energy is taking a holistic view of the entire energy production and consumption market and the value of certifying cleanliness.

Siemens Energy has established with German Energy Agency dena and TÜV Süd a partner ecosystem for the verification and certification of renewable energies, products and goods made from them along the entire Power-to-X value chain (CertaLink™). This distributed ledger technology based certification system is tamper-proof, fully automated and covers all aspects of the energy and hydrogen value chain, from renewable energy, electrolysis, Power-to-X, and H_2 re-electrification. As such, it enables a secure system to prove the sustainability of the whole energy value chain and its associated CO_2 footprint.

5 Upgrading Siemens Energy gas turbines for higher hydrogen fuel content operation

The requirement to upgrade existing gas turbines to hydrogen operation

Several reasons encourage gas turbine operators to consider hydrogen fuel retrofits:

- Upcoming stricter regulation on emissions and use of fossil fuels due to the Paris agreement (COP21), other initiatives (e.g. European Green Deal, EU Taxonomy), political instruments and country targets (more than 100 countries target or discuss targets on net zero emissions).
- Increasing carbon pricing through CO_2 taxes or emissions trading
- Customer pressure, companies and owners´ commitments to reduce carbon footprint as well as requirements from investors and financing institutions (e.g. European Investment Bank (EIB))
- Future blending of hydrogen in existing natural gas networks and pipelines, forcing existing gas turbines installed in compressor/pumping stations and existing power plants to cope with a certain hydrogen content in the fuel
- The possibility to store excess production of electricity from renewables as hydrogen (Power-to-X) and to utilize it when demand is higher. Especially in regions with good renewable conditions, hydrogen re-electrification will likely emerge as the most efficient way providing decarbonized residual load in a fully renewable based power system, where hydrogen serves as large scale, seasonal and long-term storage of renewable energy
- The possibility to utilize hydrogen rich off-gas from refinery and chemical processes

These reasons, combined with the long lifetime expectancy of gas turbines and combined cycle power plants of more than 30 years, means that every new gas turbine built today is likely to be still in commercial operation in the 2050s, when the energy system should be largely decarbonized. Hence, gas turbine-based power plants that recently began operation or are built today are very likely to require a future retrofit to operate on low-carbon fuels such as hydrogen to avoid any stranded assets in the generation fleet.

What about the installed fleet of Siemens Energy gas turbines?

The current hydrogen capability for existing gas turbines is detailed in their specific gas turbine manuals, and is usually rather low. The feasibility of retrofitting these units to accommodate higher hydrogen concentrations will depend on several factors, including site constraints, the existing equipment and combustion system, the timing of implementation, and other relevant considerations.

If operation with higher concentrations of hydrogen is desired, consultation with the Siemens Energy representative is required. Siemens Energy will provide clarification on the feasibility of higher hydrogen content, including whether the capabilities outlined in Figure 8 are applicable to the specific gas turbine, which modifications would be required and any potential impacts on service overhaul times.

High-hydrogen fuels present challenges not only for the combustion system of the gas turbine but also for the overall gas turbine package and plant.

When assessing the upgrade options for a gas turbine or plant, it is essential to evaluate the current package design and identify any necessary modifications. This ensures that all components and systems can safely operate with higher hydrogen concentrations in the fuel.

Upstream of the combustion system, the use of hydrogen fuels may necessitate modifications to component materials, pipe sizes, as well as sensors and safety systems. Downstream, it is essential to assess the exhaust path, including the Heat Recovery Steam Generator (HRSG). Variations in exhaust gas properties can affect heat transfer and corrosion rates, potentially impacting the lifespan of components. We recommend conducting a plant-specific analysis of all relevant factors to develop the most suitable solution.

To implement a hydrogen upgrade for our customers, we follow the process outlined in Figure 27. Typically, Siemens Energy's scope will focus on the gas turbine package; however, in some instances, the scope may extend to encompass the entire power plant. For more information on the implications of hydrogen for a power plant, please refer to Chapter 4.
The scope of an upgrade package is determined by the target hydrogen concentration in the fuel and the specific technical

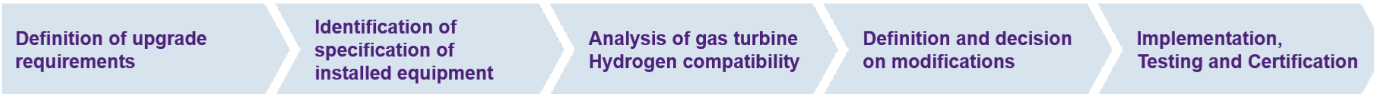

Figure 27: Process for assessment, definition, and implementation of hydrogen upgrades.

requirements, local regulatory rules as well as the site-specific configuration of the gas turbine and its associated systems.
We are committed to continuously enhancing our upgrade packages to ensure that owners of Siemens Energy gas turbines can effectively adapt their assets for higher concentrations of hydrogen fuels.

Can I upgrade my gas turbine power plant?

High-hydrogen fuels not only pose challenges for the combustion system of the gas turbine, but also to the gas turbine package and plant as well. The package design must be evaluated to ensure all components and systems are capable of safely running with higher hydrogen contents in the fuel. Upstream of the combustion system, hydrogen fuels can require changes to component materials, pipe sizes, as well as sensors and safety systems. Downstream, the exhaust path including the HRSG must be evaluated. Varying exhaust gas properties can impact heat transfer and corrosion rates, possibly impacting the life of components. Siemens Energy recommends a plant specific analysis of all factors and develop the most appropriate solution.

The effort to upgrade a gas turbine package for higher hydrogen content depends highly on the age of the gas turbine and the status of the installed package and plant auxiliaries. To implement a hydrogen upgrade for their customers, Siemens Energy uses the process defined in Figure 27.

There are several physical properties of pure hydrogen and natural gas-hydrogen mixtures that need to be considered. Hydrogen's lower density will lead to higher volumetric flow rates, higher flow velocities and/or higher skid edge pressures, requiring a review of gas fuel skid capacities. For example, as the amount of hydrogen in the fuel mixture increases, the required fuel volume flow will increase up to three times when comparing natural gas to pure hydrogen at the same pressure.

Hydrogen is a smaller molecule than methane, which will result in higher leakage rates (if used in a natural gas environment), and therefore appropriate plant modifications are required. Additionally, hydrogen's wider flammability range and low ignition energy makes it more likely that fuel leaks could ignite. The connections in the gas system, package ventilation design, and gas detection systems must be assessed for suitability for high-hydrogen fuel operation, both with respect to material suitability and explosion risks. For example, a change to stainless steel material might be needed to prevent embrittlement and enclosed electrical components may need to meet specific certification requirements (e.g.: International Electrotechnical Commission (IEC) gas groups IIC and $IIB+H_2$). For the flame detection in the package enclosure a combination of ultraviolet (UV) and infrared (IR) radiation detectors might be required.

Combustion control systems may require modification to adapt to the changes in fuel properties when increasing the hydrogen content in the fuel. Depending on the concentration and engine configuration, the use of additional thermocouples may be required which would be monitored by the control system to avoid hardware damage by flashback.

The scope of an upgrade package is related to the target amount of hydrogen in the fuel and the specific technical requirements for the application. For higher hydrogen contents, the development of an upgrade package may have to balance between the scope of the modification, the associated retrofit costs, the remaining lifetime of the plant, the regulatory emission requirements, outage intervals and resultant performance levels. In the end, the decision on what specific measures should be implemented on an existing unit always depends on the blending requirement, the site-specific configuration of the gas turbine and its surrounding systems.

Abbreviations

ACE	Advanced Combustion for Efficiency
BMWK	Bundesministerium für Wirtschaft und Klima (German Federal Ministry for Economic Affairs and Climate)
CCS	Carbon Capture and Storage
CFD	Computational Fluid Dynamics
CHP	Combined Heat and Power
CO	Carbon Monoxide
CO_2	Carbon Dioxide
DLE	Dry Low Emissions
DOE	Department of Energy
EHB	European Hydrogen Backbone (Initiative)
EIB	European Investment Bank
EU	European Union
G30	Name of Combustion System
GHG	Greenhouse Gases
HR	Hybrid Burner
HRSG	Heat Recovery Steam Generator
H_2	Hydrogen
IEA	International Energy Agency
IEC	International Electrotechnical Commission
IPCC	Intergovernmental Panel on Climate Change
IR	Infrared
LOHC	Liquid Organic Hydrogen Carriers
MW	Megawatt
Nm^3	Normal Cubic Meter
NO_x	Nitrogen Oxides
N_2	Nitrogen
NEC	National Electric Code
NFPA	National Fire Protection Association
O&M	Operation and Maintenance
PCS	Platform Combustion System
PPMV	Parts Per Million Volume
SAF	Sustainable Aviation Fuel
SCR	Selective Catalytic Reduction
SFI	Swirler Fuel Injection
SLM	Selective Laser Melting
TWh	Terawatt-hour
UK	United Kingdom
ULN	Ultra-Low NO_x
US	United States
UV	Ultraviolet
WLE	Wet Low Emissions
XLPE	Cross-linked polyethylene

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