CPV Valley Energy Center
50 Braintree Hill Office Park
Suite 300
Braintree, MA 02184

March 30, 2021

Transmitted via email to chris.hogan@dec.ny.gov

Mr. Christopher M. Hogan
Chief, Major Project Management Unit
Department of Environmental Conservation
Division of Environmental Permits
625 Broadway, 4th Floor
Albany, NY 12233-1750

Re: CPV Valley, LLC – CPV Valley Energy Center
Title V and IV Permit Applications
DEC ID 3-3356-00136/000010 & 00009
First Supplemental Response to November 29, 2020 Notice of Revocation of Complete Application and Notice of Incomplete Application

Dear Mr. Hogan:

As you know, CPV Valley, LLC ("Valley" or "Applicant") seeks permits under Title V and IV of the Clean Air Act and Article 19 of the New York Environmental Conservation Law ("ECL") (collectively, the "Application") for the Valley Energy Center ("Facility"). By letter dated March 8, 2021, Valley submitted a response to the New York State Department of Environmental Conservation's ("NYSDEC" or "Department") Notice of Revocation of Complete Application and Notice of Incomplete Application dated November 29, 2020 ("NOIA") regarding Valley's Application. Valley's March 8, 2021 submission included a report prepared by ICF demonstrating why NYSDEC's issuance of a Title V permit would not interfere with the Statewide greenhouse gas ("GHG") emission limits established in the Climate Leadership and Community Protection Act Section 7 [2] (Chapter 106 of the Laws of 2019) (the "CLCPA"), ECL Article 75, and recently promulgated at 6 NYCRR Part 496 (eff. December 30, 2020). This letter is intended to supplement Valley's March 8, 2021 submission and provide information related to the technical feasibility of using renewable natural gas ("RNG") and hydrogen sourced using renewable energy ("green hydrogen") at the Facility.[1]

As part of its report, ICF also assessed consistency with the state's long-term energy targets of a zero-emissions statewide electric system by 2040. ICF's modeling and conclusions presumed that RNG and/or green hydrogen would be CLCPA-compliant

[1] Valley reserves all rights to challenge NYSDEC's revocation of its May 2019 application completeness determination in any administrative or judicial action or proceeding.

zero-emissions fuel sources able to be used beyond 2040 to meet the statewide electric system targets. The ICF report set forth assumptions regarding combustion of RNG resulting in zero GHG emissions, and provided an evaluation of the economic feasibility and anticipated adequacy of RNG / green hydrogen supply.[2] Technical feasibility of using RNG or green hydrogen at the Facility, however, was outside the scope of ICF's report. As discussed herein, and based on the current state of knowledge concerning these evolving technologies, potential future use of RNG and/or green hydrogen could be technologically feasible should Valley be required to use such fuels to remain CLCPA compliant beyond 2040.

Green Hydrogen

Green hydrogen is a zero emission fuel produced through the process of electrolysis, which uses renewable energy to split water molecules into their elemental components. Hydrogen produced as a result of electrolysis can then be stored and combusted by dispatchable energy resources to produce electricity when it is needed.

The Facility uses two Siemens F-class combustion turbine generators ("CTG") model SGT6-5000F/W501F and employs state-of-the-art emissions control technology. These CTGs use Siemens Energy's Dry Low Emission ("DLE") combustion technology that can currently burn up to 15% hydrogen with no or minimal upgrades and up to 30% hydrogen if retrofitted with currently available technology. Included herein as **Attachment 1** is a Siemens Energy hydrogen White Paper detailing current hydrogen capabilities of Siemens' gas turbines (Attachment 1 § 2, Figure 3, pgs. 8-9). By 2030, Siemens anticipates that its large gas turbine DLE systems will be capable of running on 100% hydrogen (Attachment 1 § 3, pg. 12; Attachment 1 § 5, Figure 20, pg. 19). This will be accomplished by using various technology enablers such as incorporating modified or new burner designs into the existing turbines (Attachment 1 § 5, pgs. 18-19).

As a global power systems leader in designing a new generation of turbines and engines to run on hydrogen, Siemens Energy's efforts to obtain its 2030 goals are exemplified by present day efforts. For example, Siemens Energy is supplying two gas turbine packages that will eventually operate on 100% hydrogen for the Leipzig Süd district heating power plant in Germany[3] and has committed to having gas turbines capable of running on 100% hydrogen with DLE technology across its gas turbine portfolio.[4] While Valley cannot commit to using green hydrogen at this time, the

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[2] ICF's analysis regarding market expectations, supply, and economic feasibility of RNG and green hydrogen is consistent with a similar report ICF prepared in support of a Title V application for the Danskammer Energy Center ("Danskammer Report") (NYSDEC ID: 3-3346-00011/00017) to which Department Staff had brought to Valley's attention during a technical conference (*see* Case 18-F-0325, Application of Danskammer Energy, LLC, Fourth Supplement to the Application [Dec. 22, 2020] [Item No. 126] (available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=56697&MNO=18-F-0325). To the extent that there are overlapping questions related to statewide renewable fuel market economics, availability, or other similar issues that are not plant specific that NYSDEC requires in order to perform its CLCPA § 7 analysis, Valley adopts such information and respectfully refers Staff to the Danskammer Report for such information.

[3] See https://fuelcellsworks.com/news/leipzig-will-soon-be-able-to-heat-with-hydrogen-thanks-to-siemens-award-winning-turbines/.

[4] See https://www.worldenergy.org/assets/downloads/Siemens_Commitment.pdf.

information herein and in the attachments shows the current and future conversion potential to operate on green hydrogen by 2040.

Renewable Natural Gas

RNG is a pipeline compatible gaseous fuel derived from biomass or other renewable sources that after conditioning, can be up to 99% methane. The process of capturing RNG does not create new carbon emissions, but rather, recycles carbon that was already in circulation and which would have resulted in the emission of GHGs absent conversion to RNG. New York considers biogas from sources like landfill and manure digestion to be Main Tier Eligible Electric Generation Sources, which are the primary sources used to reach state Renewable Portfolio Standards ("RPS").[5] While RNG is not included as a qualified "renewable energy system" under the CLCPA, the New York State Department of Public Service ("NYSDPS"), the agency responsible under the CLCPA for implementing a program to achieve the 2030 and 2040 statewide electric system goals, has already recognized GHG reductions and the climate change benefits of RNG.[6]

RNG is considered suitable for many end-use applications and considered suitable for inclusion in general pipeline systems. While RNG production may require new interconnections to pipelines, RNG supply does not necessarily require additional natural gas system infrastructure, such as transmission and distribution pipes. RNG can be transported in existing natural gas pipelines, compressed and dispensed at existing compressed natural gas stations, or used by conventional natural gas burning end users.[7]

Importantly, because RNG is in effect methane that is sourced from biomass or other renewable sources (rather than geological natural gas), it can be transported to power plants such as Valley's Facility using existing natural gas infrastructure and used directly in Valley's CGTs with little to no modifications. As such, use of RNG is technically feasible at the Facility.

If RNG is either deemed a CLCPA compliant fuel or otherwise permitted for use because of its neutral or GHG reducing impacts, the Facility, being one of the most efficient and cleanest power plants currently operating in the region, is well positioned to aid the state in meeting its CLCPA targets <u>while</u> ensuring grid reliability.

Future Reliance on Renewable Fuels

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[5] See https://www.nyserda.ny.gov/All-Programs/Programs/Clean-Energy-Standard/Renewable-Portfolio-Standard.

[6] Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, Draft Supplemental Environmental Impact Statement [Issued Feb. 23 2016] [Item No. 84], 5-55 (available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=48235&MNO=15-E-0302) ("Closed-loop cycles [where biomass is grown from land solely dedicated to the production of energy resources] are generally carbon neutral because the carbon released during combustion is equivalent to the carbon absorbed while the biomass is grown. Open-loop cycles [where biomass resources are typically byproducts of other activities] result in GHG emissions reductions because the combustion process produces primarily CO2 while natural biomass decay produces CO2 and methane. Methane has more global warming potential than CO2; decreases in methane production result in a lifecycle reduction of greenhouse gases.").

[7] U.S. E.P.A, An Overview of Renewable Natural Gas from Biogas, July 2020, § 3.0 (available at https://www.epa.gov/sites/production/files/2020-07/documents/lmop_rng_document.pdf).

To date, neither NYSDEC nor the PSC have fully developed their CLCPA regulations and programs, and as such, there is no applicable regulation or other guidance as to whether RNG or green hydrogen would be deemed a zero GHG emission resource. Future possible regulation or guidance could include (a) installation of electric power generation resources that reduce GHG emissions by displacing older inefficient plants, (b) allowing such generation resources to operate beyond 2040 by using fuels that are in fact carbon-neutral or GHG reducing (even if not included within the technical definitions of the CLCPA), (c) modifying program requirements (as allowed under the CLCPA), or (d) ceasing operations unless the PSC determines that the resource is necessary for grid reliability. While ultimately these pathways are within the purview of PSC and/or NYSDEC programs implementing the CLCPA, and would be based on future changes in technology and infrastructure, the Facility is well positioned to operate within any of the above potential scenarios, reduce GHG emissions from the state electrical system, and be consistent with the CLCPA future targets.

To that end, Valley is willing to support green hydrogen research and development by undertaking a multi-year study after its Application is approved and permits are granted with appropriate permit conditions[8] that examines feasibility of using green hydrogen at the Facility and further assessing hydrogen's commercial and economic viability for use at the Facility.

Conclusion

Based on the information herein and Valley's prior submissions, it is technically feasible for the Facility to use or be converted to use alternative emissions-free fuels such as RNG or green hydrogen, if and when such sources become commercially and economically available in the future market place. Valley's Application is therefore consistent with the State's long-term targets for renewable and zero emission electricity required under the CLCPA, and the Facility will continue to operate complementarily with existing and future intermittent renewable resources and offer reliability for the unforeseeable needs of the grid in the long term.

Thank you for your continuing attention Valley's Application.

Very truly yours,

Donald G. Atwood
Asset Manager Representative

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[8] *See e.g.* Air Title V Facility for Edgewood Energy LLC (Permit No. 1-4728-03244/00005) (eff. 10/14/2020) condition 51 (stating "[p]ursuant to The New York State Climate Leadership and Community Protection Act (CLCPA) and Article 75 of the Environmental Conservation Law, emission sources shall comply with regulations to be promulgated by the Department to ensure that by 2030 statewide greenhouse gas emissions are reduced by 40% of 1990 levels, and by 2050 statewide greenhouse gas emissions are reduced by 85% of 1990 levels") (available at https://www.dec.ny.gov/dardata/boss/afs/permits/147280324400005_r2.pdf).

SIEMENS
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Hydrogen power with Siemens gas turbines

Reliable carbon-free power with flexibility

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 another key role in enabling a smooth transition from fossil to decarbonized power systems because they provide highly flexible and dispatchable generation to support grids largely dominated by intermittent renewable power. 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.

Karim Amin

Chief Executive Officer – Generation
Siemens Energy

Thorbjörn Fors

Chief Executive Officer – Oil & Gas
Siemens Energy

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1. Why use hydrogen as a fuel for gas turbines?

The need for hydrogen to de-carbonize power generation

Global warming, caused by anthropogenic emissions such as carbon dioxide and methane, 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 previous target of limiting the global temperature rise to no more than 1.5 °C required targeting annual global emissions in the 25–30 gigatons (Gt) carbon dioxide (CO_2) equivalent per year range by 2030 [1], but in 2018 annual worldwide emissions reached 33.1 Gt CO_2 [2]. The energy sector is a major contributor to global greenhouse emissions with a share of approximately 36% across advanced economies while the remaining 64% are emitted from other sectors such as industry, mobility and residential [2].

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 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 conventional fossil fuel 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 mid-day to evenings, thermal and chemical solutions are more suitable to store energy for longer periods.

Of the conventional fossil-fuel generation technologies gas turbines are the cleanest option. The use of natural gas fired open cycle gas turbines, instead of coal power plants, reduces specific carbon emission by 25% to 50%[1]. Additional reductions of carbon emissions can be achieved by converting simple cycle units to combined cycle power plants which yields another 20% to 23% reduction[2]. 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 reach 85% [3].

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 [4] but switching to natural gas power generation and improving efficiencies are only the first steps. In the long term, displacement of natural gas fuel with 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. For hydrogen mixtures the relationship between CO_2 reduction and hydrogen content is non-linear because the hydrogen molecule has 2.5 times the energy content of methane by mass, but one third on a volumetric basis. CO_2 emissions scale by hydrogen mass content in the fuel, while typically hydrogen and natural gas mixtures are defined on a volumetric basis, as in Figure 1.

Substituting natural gas with hydrogen over time means that investments in gas power plants today will have long-term viability, as mixing hydrogen into the natural gas stream for gas turbine operation will help plants remain eligible for capacity mechanisms. For example, as of July 4, 2019 the EU is limiting new power plants to less than 550 grams of CO_2 per kilowatt hour (gCO_2/kwh) to participate in the capacity mechanisms of the internal market and restricting the participation of legacy plants by 2025[3][5].

[1] Assumptions: coal emissions 750-1000 gCO_2/kwh; simple cycle gas turbines emissions 490-565 gCO_2/kWh for operation on 100% methane

[2] Assuming combined cycle gas turbine emissions range 305-395 gCO_2/kWh

[3] As of July 1, 2025, units that began operation before July 4, 2019 will be required to emit less than 550 gCO_2/kWh of electricity and less than 350 kilograms CO_2 of fossil fuel origin on average per year per installed kilowatt hour electric in order to qualify for the capacity mechanisms [5].

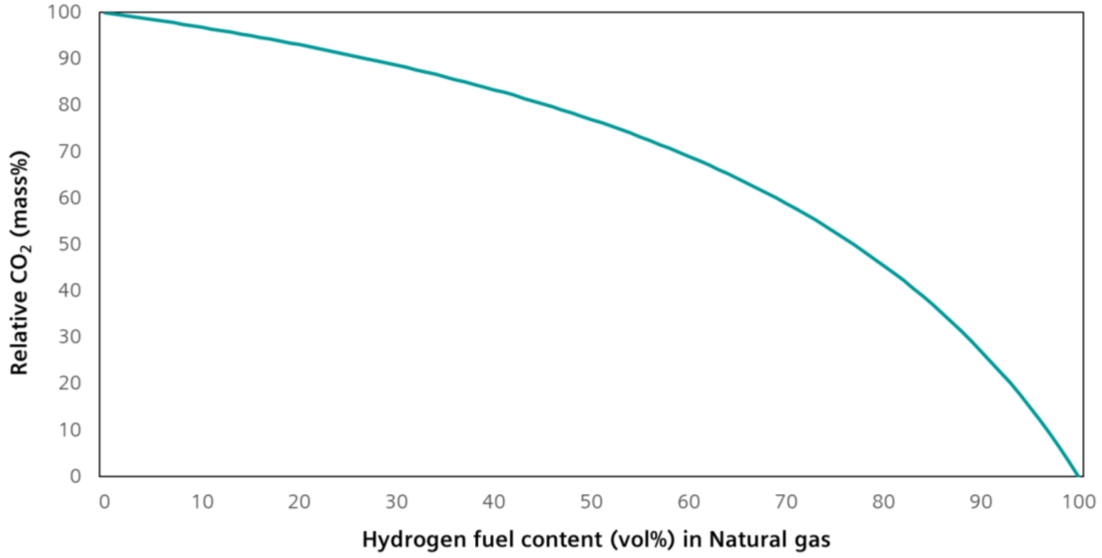

Figure 1: Hydrogen volume percentage (vol%) in the fuel versus the relative CO_2 emissions from the combustion process[4]

As noted in Figure 1, in order to reach a 50% reduction in CO_2 emissions by mass, approximately 80 vol% hydrogen fuel content is needed. The amount of hydrogen required to operate large gas turbines at this level of hydrogen fuel mixture is not economically viable today, but for smaller gas turbines these hydrogen levels are within reach, especially when considering hydrogen flare gases from petrochemical sources. With smaller amounts of hydrogen in the fuel it is still possible to make significant emission reductions. 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 1.26 million metric tons of CO_2 for a reference 600 megawatt (MW) combined cycle power plant that runs for 6000 hours a year at an average 60% efficiency.

This hydrogen fuel blending not only lowers CO_2 emissions of gas turbines, it also ensures that the gas turbines can participate in electricity storage and re-electrification. Hydrogen can serve as a chemical storage vehicle by being produced through electrolysis during times of excess renewable energy generation and then used to fuel gas turbines or sold to other industries, as shown in Figure 2. In addition to electrolysis, new technologies are being developed to produce hydrogen from renewable sources[5].

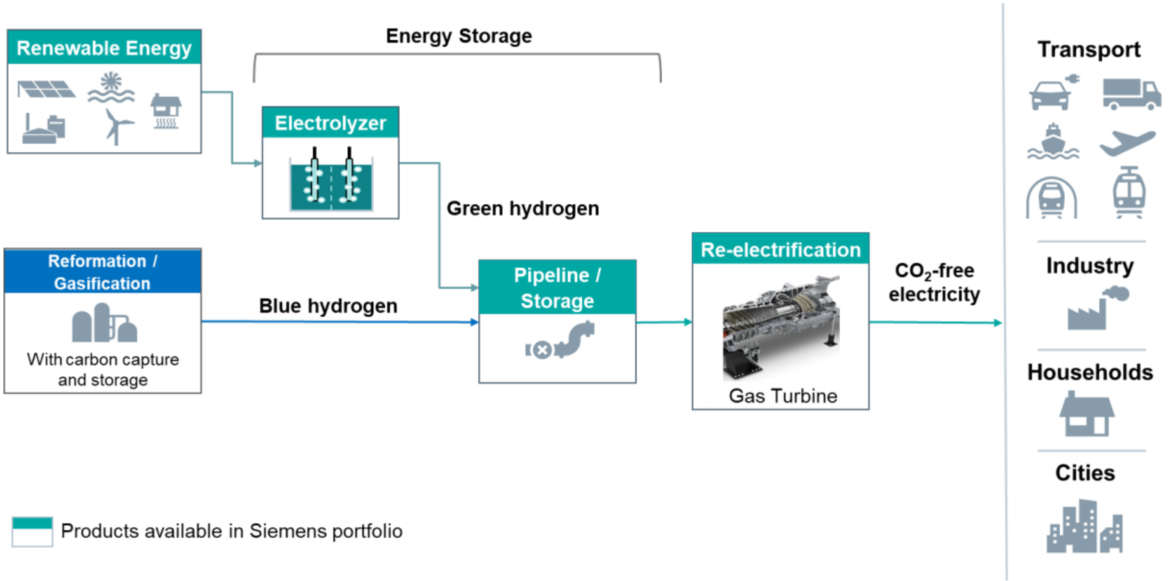

Figure 2: Example of the integration of technologies to produce and use hydrogen

[4] Assumes 100% combustion efficiency

[5] An example is the U.S. Department of Energy's Lawrence Berkeley National Laboratory and the Joint Center for Artificial Photosynthesis (JCAP) artificial photosynthesis device called a hybrid photoelectrochemical and voltaic (HPEV) cell which produces electricity and from sunlight and water [6].

The impact of hydrogen gas turbines on the power sector

In January 2019, the EUTurbines industry association members committed to developing gas turbines capable of operating on 100% hydrogen by 2030 [7]. 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 and prevents stranded assets due to regulations on emissions reductions. For the grid, gas turbines operating on hydrogen fuel or hydrogen fuel mixtures are dispatchable and flexible generation capacity available to keep the grid stable. For the power sector, continuing to use the huge 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 industrial applications can provide steam and heat that would otherwise need to be substituted by electric heaters or biomass plants.

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:

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, depleted oil and gas fields, or used in industry (ex: Food & Beverage) to produce higher value products. CO_2 capture is not 100% efficient, so some CO_2 will always be released to the atmosphere.
Black / Grey / Brown Hydrogen	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. However, in combination with power generation the associated CO_2 emissions with generating hydrogen this way is equal to or greater than the avoided emissions from burning natural gas in a gas turbine.

Application paths for gas turbines

There are three distinct application paths emerging for gas turbines related to operation on 100% hydrogen or hydrogen-natural gas blends.

Hydrogen blended into natural gas network

Hydrogen produced from any source (green, blue or grey) is injected into the existing natural gas network. In this scenario, any consumer (industrial, commercial or domestic) will now be required to operate gas-fired equipment using natural gas with a hydrogen content. This may pose a challenge to many consumers and 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 hydrogen, the injection frequency (continuous or intermittent), the complexity of the network, and the distance of the consumer from the point of injection. This would bring even more challenges to today's consumers connected to the gas grid.

In some cases, it has been proposed that consumers of high amounts of gas operate on higher hydrogen concentrations than other users. This would require the construction of dedicated hydrogen pipelines capable of transporting pure hydrogen. Hence, an alternative option to hydrogen blended into the existing pipeline is a second pipeline installed specifically for hydrogen to run in parallel to the natural gas lines.

High pressure transmission pipelines are unlikely to exceed 25 vol% hydrogen due to concerns over leakage through seals and welds, and hydrogen embrittlement of steel pipes. Older gas networks built for town or city gas, e.g. old German town gas pipes, can accept hydrogen contents 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 [8]. Plans are also being made to allow transportation of pure hydrogen in liquid form by ship to allow worldwide trading, in case underwater pipelines are not an option [9].

Such an approach will require regulators to redefine the permissible specifications for “pipeline quality” natural gas. 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.

Hydrogen ‘peakers’

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 power plants to provide zero or low carbon electricity and compensate for insufficient amounts of renewable electricity, thus providing sustainable backup power.

100 percent hydrogen baseload operation

Dedicated hydrogen production facilities could be created to fuel baseload or flexible baseload power plants, or combined heat and power facilities. This would allow zero carbon gas turbine-based power generation to provide the required electricity in networks with low renewables penetration or lack of other sources of zero carbon electricity. Within the next few years, blue hydrogen facilities are the most likely production sources for utility-scale 100% hydrogen applications because of the high amount of fuel required for large gas turbines.

2. Siemens hydrogen capability

Siemens gas turbine hydrogen capability

Siemens 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 3 for the "high-hydrogen options" across the portfolio for new unit applications that are available on specific request. For installed units the 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.

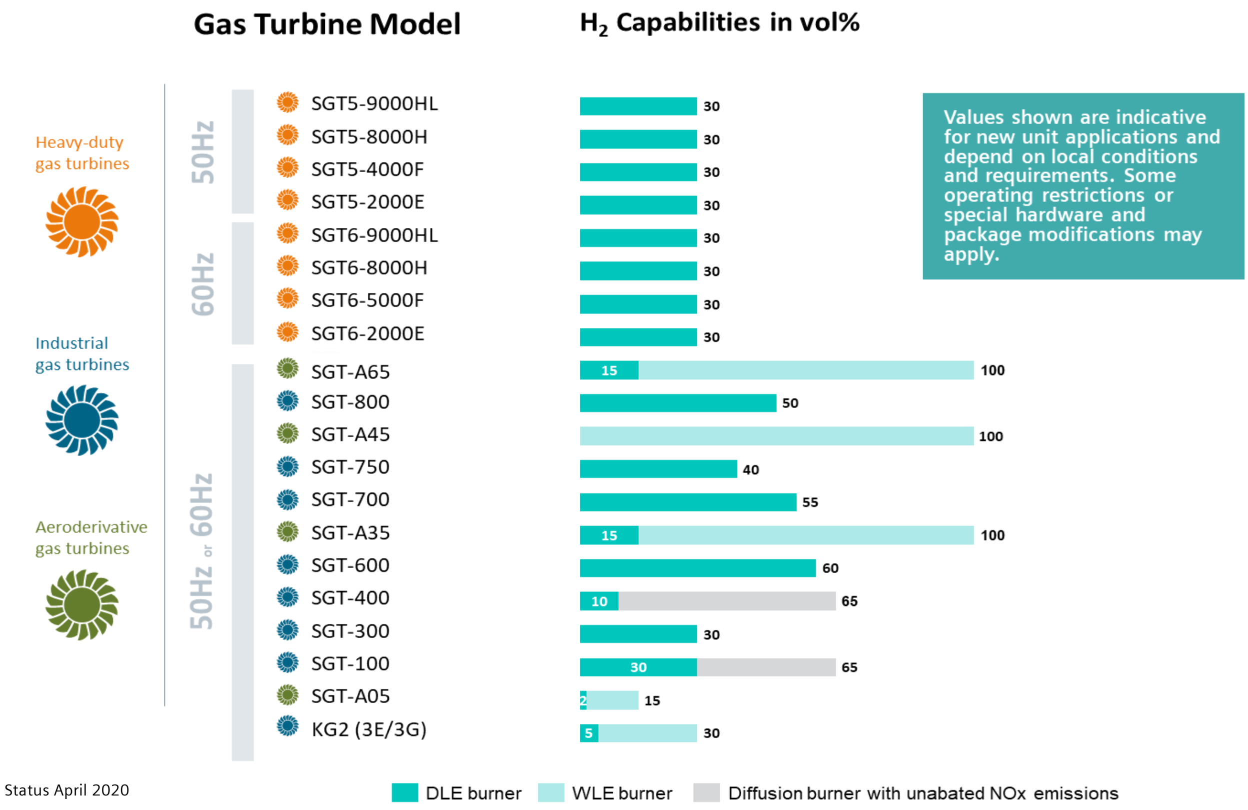

Figure 3: Siemens gas turbine portfolio hydrogen capability (available as "high-hydrogen" options) for new unit applications

Siemens gas turbine hydrogen operating experience

Siemens fleet experience with high hydrogen content fuels is extensive, with more than 55 units around the world amassing 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 gas turbine portfolio. Experience has been gained on unabated diffusion flame, Wet Low Emissions (WLE), and Dry Low Emissions (DLE) combustion technologies. With this experience Siemens has gained a high confidence in managing hydrogen on a plant level and within our gas turbine systems.

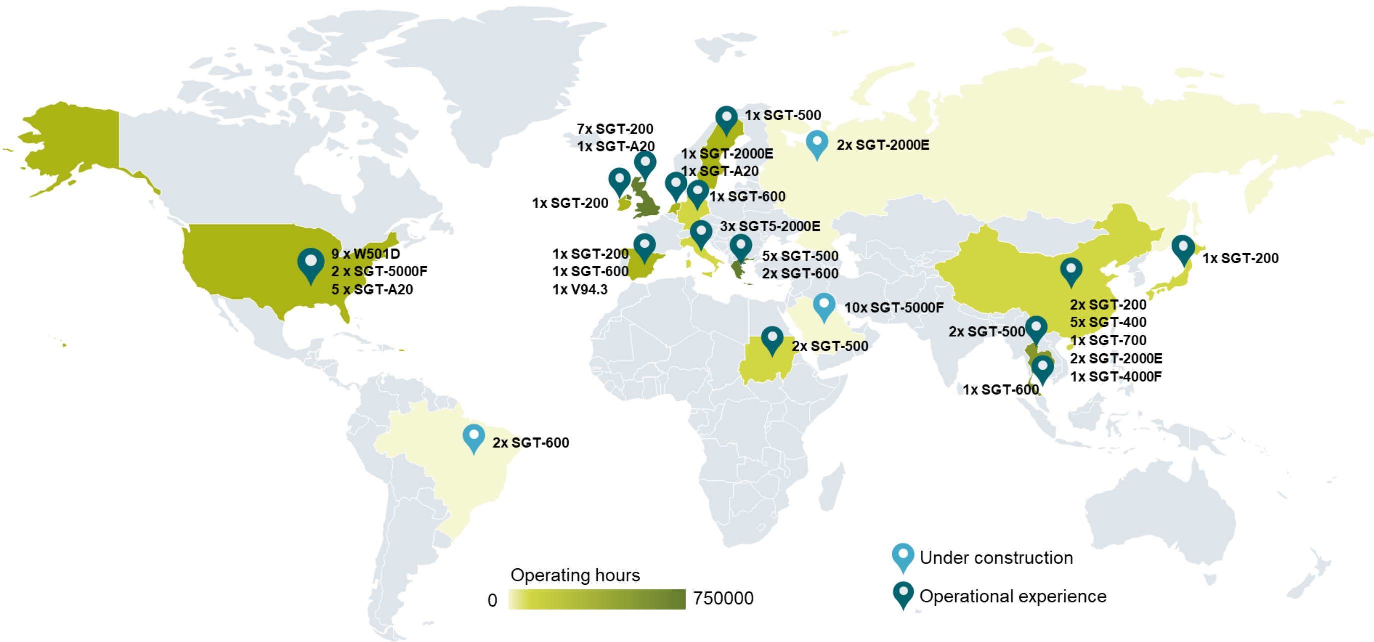

Figure 4: Siemens' high-hydrogen fleet experience

3. 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 more than three times that of methane and the autoignition delay time of hydrogen is more than three time lower than methane, as shown in Figure 5 for flame temperatures of 1600 °C. 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.

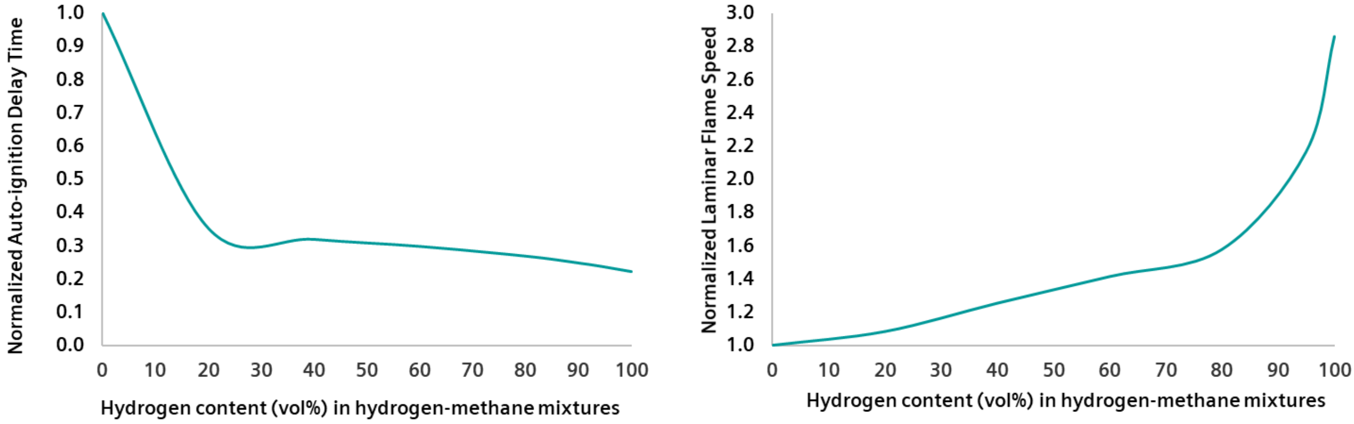

Figure 5: Hydrogen's impact on auto-ignition delay and flame speed for hydrogen-methane mixtures[6]

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 speeds with hydrogen increase 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 6). 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 reduce the life of combustion system components

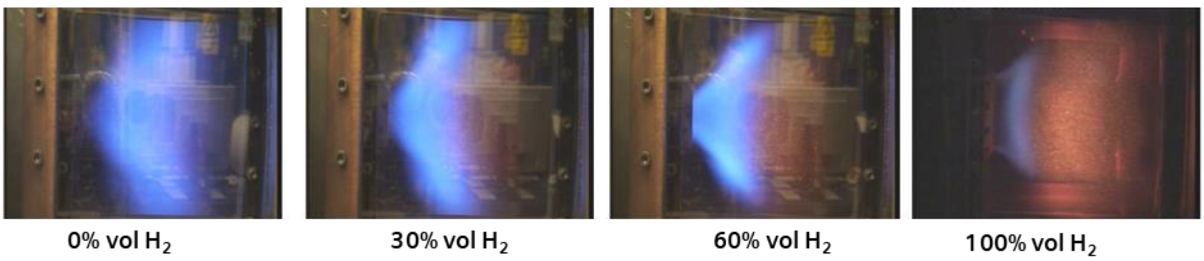

Figure 6: Flame position changes with increasing hydrogen fuel content, showing the most compact flame at 100% hydrogen. Also note how the 100% hydrogen flame is not as luminous as the natural gas flame.

[6] Produced with Chemkin using the GRI 3.0 Mechanism. Conditions: inlet temperature 450 °C, inlet pressure 20 bar, Adiabatic flame temperature 1600 °C

Siemens 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 hydrogen fuel contents to allow the systems to operate safely, meet NO_x emissions limits and manage varying fuel compositions. Siemens is in the process of extending the hydrogen capability of its DLE systems, with more details provided in the following sections.

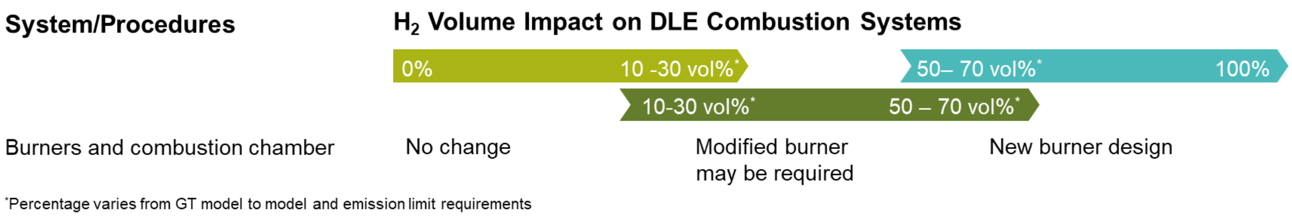

Figure 7: Hydrogen fuel volume impacts on DLE combustion systems

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 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 mean 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 often being available at the plant as a byproduct of gasification processes. Using the nitrogen produced as a biproduct 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.
- 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

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 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 and 2010s with governmental support (EU, United States Department of Energy (US DOE) [10], and German Federal Ministry for Economic Affairs and Energy (BMWi) [11]). 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.

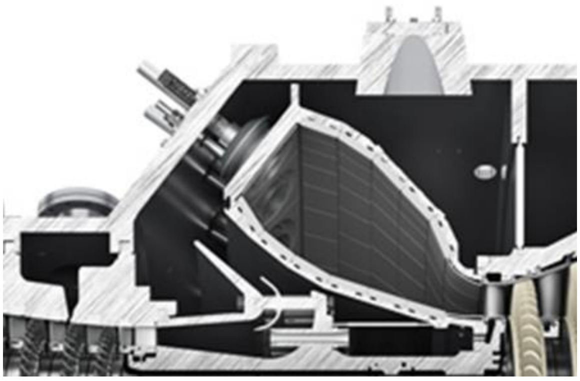

Figure 8: 4000F annular combustion chamber

Siemens' 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 also capable to run on up to 30 vol% hydrogen. By 2030, the large gas turbine DLE systems are targeted to be capable of running on 100% hydrogen.

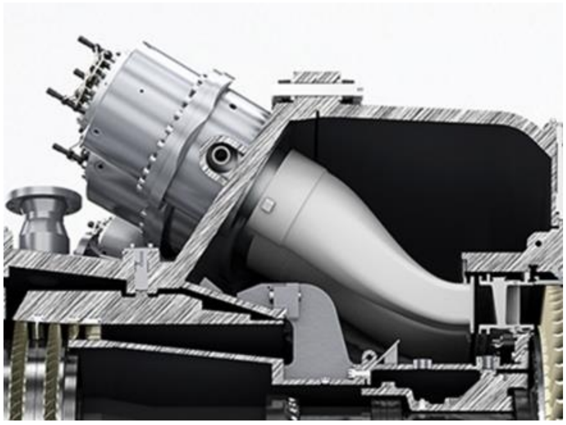

Figure 9: SGT-5000F combustion system

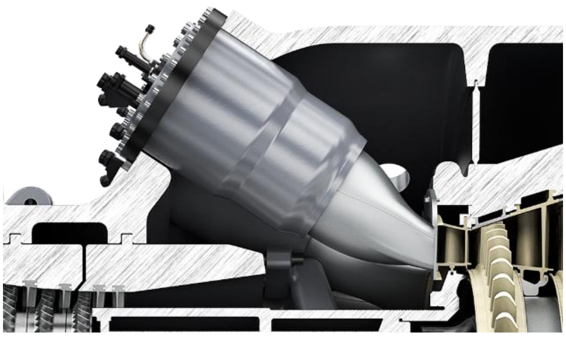

Figure 10: SGT5/6-9000HL combustion system

Siemens 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 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.

Non-DLE Technology

Since the early 1990s, Siemens' 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) [12]. These synthetic gases (syngas) are mixtures of varying composition, but typically have significant fractions of hydrogen and CO, as well as inert gases (N_2, CO_2, steam).

Medium industrial gas turbines

DLE technology

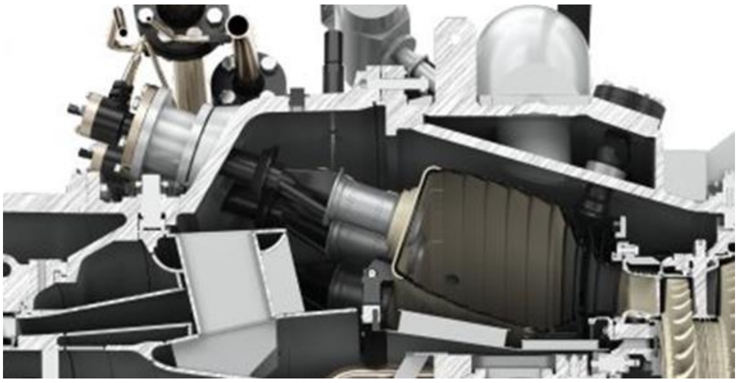

Figure 11: 3rd generation DLE combustion system

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 60 vol% hydrogen on the SGT-600, 55 vol% on the SGT-700, and 50% on the SGT-800. The SGT-600 has run an engine test with close to 80 vol% hydrogen, and a variant of the 3rd generation DLE burner, that is used in all three engines, has been recently tested at the Siemens 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.

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 [13].

Siemens has recently sold two SGT-600, for a project in Brazil that will be commissioned to operate on 60 vol% hydrogen.

Non-DLE technology

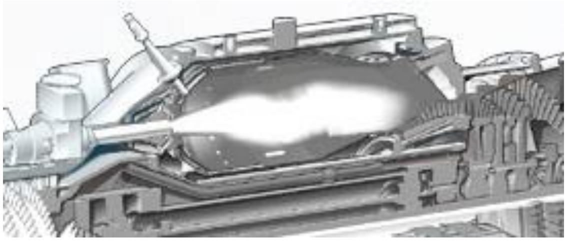

Figure 12: SGT-500 Non-DLE combustion system

Siemens 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.

Aeroderivative gas turbines

DLE technology

The Siemens aero-derivative engines, specifically the SGT-A35 and SGT-A65, see Figure 13, 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 thermo-acoustics as the heat release profile through the combustor can be varied for a given constant power. The SGT-A35 and SGT-A65 combustion systems have the capability to run with up to 15 vol% hydrogen today, and the A05 is capable of 2%.

Figure 13: SGT-A65 DLE combustion system

Non-DLE technology

Non-DLE systems in the Siemens 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 15 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.

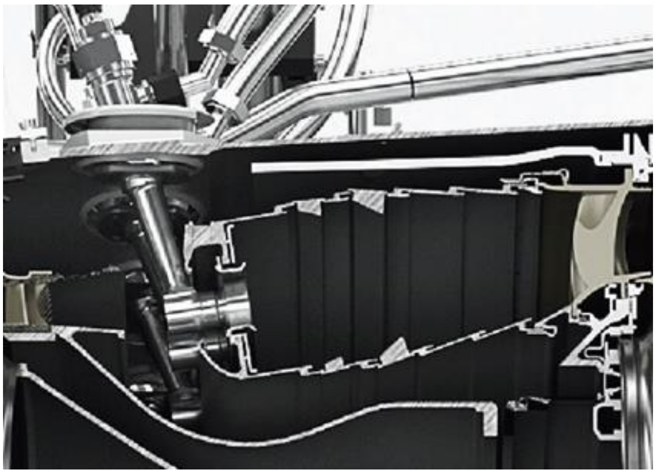

Figure 14: SGT-A65 and A45 Non-DLE combustion system

Small industrial gas turbines

DLE technology

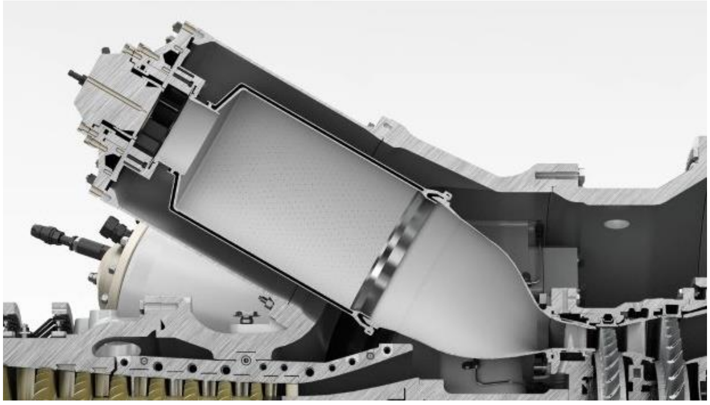

Figure 15: SGT-400 DLE combustion system

Siemens 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 hydrogen roadmap. The SGT-400 combustion system has been developed to run on up to 10 vol% hydrogen [14].

Non-DLE technology

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

Summary

Over the last few decades, hydrogen capability in the Siemens' 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 is answering this demand with a development roadmap as shown in section 5.

4. Upgrading Siemens gas turbines for higher hydrogen operation

What about the installed fleet of Siemens gas turbines?

The hydrogen capability for existing gas turbines is always communicated with the gas turbine manual. If higher hydrogen fuel contents are desired, please check with your Siemens point of contact. Siemens will clarify if higher contents are possible without any further changes to the system and if service overhaul times would be affected.

For medium size industrial gas turbines, the standard capability is up to 15 vol%, but it depends on the package design as well as local certification requirements. An analysis needs to be conducted on the existing site to identify which components need to be changed to be able to use a higher mix of hydrogen. The industrial gas turbines today with 3rd generation DLE system (standard for all new unit SGT-700 and SGT-800 and an option for SGT-600) have a high capability to burn hydrogen with levels of 50-60 vol%. Upgrading existing units to these levels is also possible.

For gas turbines with WLE systems the hydrogen fuel capability will be driven by the certification standard of package systems and will usually be around 25 vol%, depending on local rules. However, a check by Siemens should always be conducted, to clarify certification requirements and any impacts on service overhaul times. It is also possible to increasing the hydrogen capability of these units with an upgrade.

Can I upgrade my gas turbine power plant?

High-hydrogen fuels not only pose challenges for the combustion system of the gas turbine, but the package and plant as well. The package design must be checked to make sure 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. We recommend a plant specific FEED study to analyze all factors and develop the most appropriate solution.

For the Siemens fleet, certain upgrades are available for hydrogen operation. For example, for Siemens' gas turbines SGT-2000E and SGT-4000F, the H_2DeCarb upgrade package is available for higher hydrogen contents. This upgrade package needs to be adapted to each project specifically. The SGT-2000E with this upgrade package can operate with up to 30 vol% hydrogen fuel, while the SGT-4000F can operate on up to 15 vol% hydrogen fuel. For other machines in the Siemens fleet, upgrades to higher hydrogen contents can be requested based on a project specific pre-study.

The effort to upgrade a Siemens gas turbine package for higher hydrogen content depends highly on the age of the gas turbine and the status of the installed auxiliary package and power plant. To implement a hydrogen upgrade for our customers, we use the process defined in Figure 16.

Figure 16: Process for assessment, definition and implementation of hydrogen upgrades.

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, 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 number of 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 might be needed to prevent embrittlement and enclosed electrical components may need to meet specific certification requirements (ex: 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) 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 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 and resultant performance levels. For example, with DLE systems in some cases the primary zone temperature might need to be reduced in order to keep the NO_x level emissions compliant. Upgrade measures may be able to compensate for the performance impact due to reduced overall combustion temperature. In the end, the decision on what specific measures should be implemented on an existing unit always depends on the site-specific configuration of the gas turbine and its surrounding systems.

We are continuously working on improving our upgrade packages to ensure that owners of Siemens gas turbines can upgrade their assets for higher hydrogen fuels if economically feasible.

5. Technology enablers and Siemens roadmap toward 100 % hydrogen gas turbines

Siemens technology enablers for high-hydrogen operation

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

High fidelity Computational Fluid Dynamics (CFD)

Advanced CFD tools allow Siemens' 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 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 3. To account for this effect, Siemens 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.

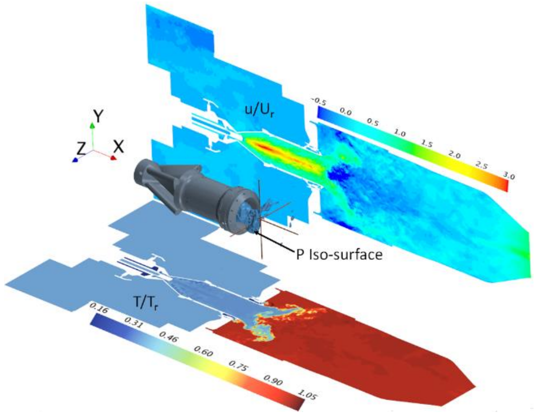

Figure 17: CFD flow field overview from a study of SGT-800 3rd generation burner with high-hydrogen fuels [15]

High pressure combustion testing

Despite of all the advances that were made in past years in the area of CFD, combustion today is still a complex field. Testing our combustion systems at 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. The Clean Energy Center in Berlin is Siemens' facility for high pressure (35 bar) combustion tests, see Figure 18. The facility supports testing of components and systems for the whole Siemens 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 we will be able to support the increased demand of hydrogen applications. With this in-house capability Siemens ensures new knowledge is shared across our fleet and timely support is provided to customer projects for special fuels like hydrogen.

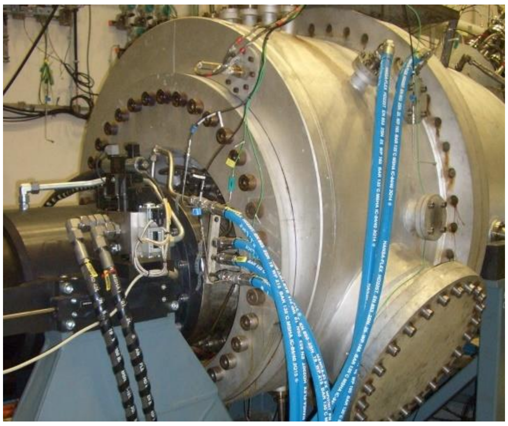

Figure 18: Clean Energy Center facilities for high pressure combustion tests, Berlin, Germany

Additive manufacturing

Siemens' additive manufacturing technology enables the integration of innovative design features and allows technology validation time to be accelerated by up to 75%. This allows 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 by allowing the creation of complex cooling features and fuel routing that would not previously have been possible [16]. These features are vital when it comes to ensuring stable combustion of hydrogen.

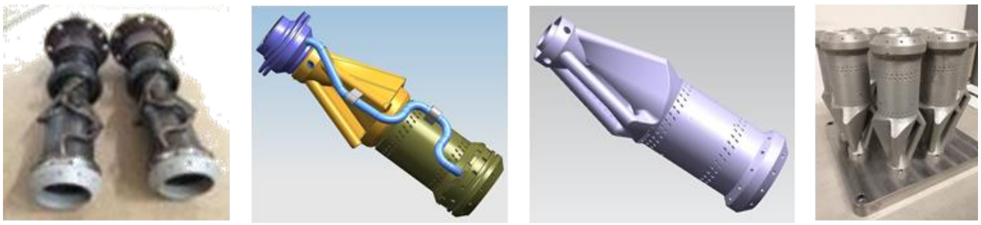

Figure 19: Fuel burner design progressions from welded (far left) to SLM additive manufacturing (far right) for 3rd generation DLE burner

Hydrogen roadmap for Siemens gas turbines

Finally, our 100% hydrogen gas turbine program combines extensive technology development for industrial and utility power generation applications. Since the 1960s, Siemens has gained experience with high-hydrogen fuels on non-DLE combustion systems. Beginning in the early 2000s Siemens has invested in the development of DLE hydrogen combustion technology. By 2030, Siemens intends to have gas turbines with the capability of operating on 100% hydrogen fuel with DLE technology available across our gas turbine portfolio. To achieve this target, we are continuously developing the necessary technologies and implementing these new designs into our product portfolio. Siemens' aeroderivative gas turbines are available to run on 100% hydrogen fuel with WLE combustion systems today. Based on the availability of hydrogen in the different sectors, we will push our hydrogen technology forward to ensure that customer needs are met.

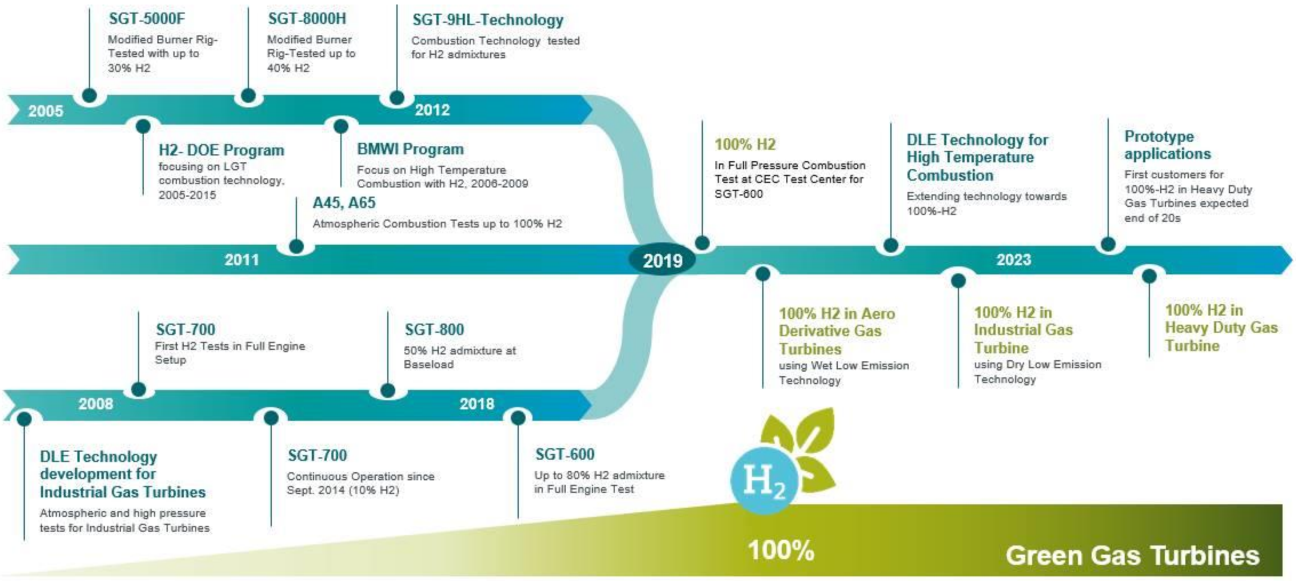

Figure 20: Siemens 100% hydrogen gas turbine roadmap

Abbreviations

BMWi	Bundesministerium für Wirtschaft und Energy (German Federal Ministry for Economic Affairs and Energy)
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
EU	European Union
G30	Name of Combustion System
HR	Hybrid Burner
HPEV	Hybrid Photoelectrochemical and Voltaic
H_2	Hydrogen
IPCC	International Panel on Climate Change
NO_x	Nitrogen Oxides
N_2	Nitrogen
PCS	Platform Combustion System
UK	United Kingdom
ULN	Ultra-Low NO_x
US	United States
XLPE	Cross-linked polyethylene

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Freyeslebenstrasse 1
91058 Erlangen, Germany

Siemens Energy Inc.
15375 Memorial Drive
Houston, TX 77079
United States

For more information, please contact:
support.energy@siemens.com

Editors (Siemens AG):
Ute Rohr

Authors (Siemens AG):
Kathleen Bohan, Eva Verena Klapdor, Bernd Prade, Anders Haeggmark, Ghenadie Bulat, Nakul Prasad, Michael Welch, Peter Adamsson, Thomas Johnke

Pictures and graphics:
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