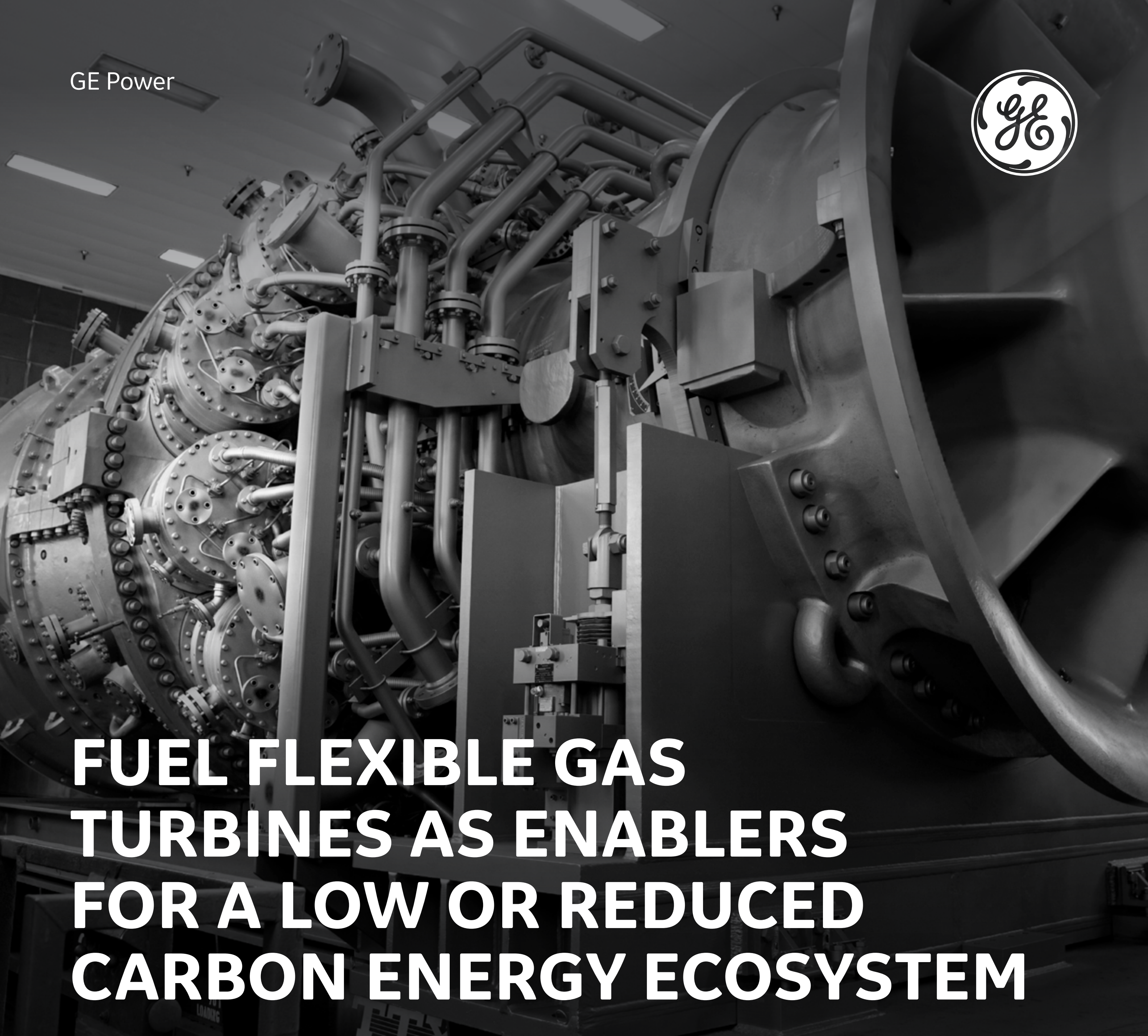

GE Power

FUEL FLEXIBLE GAS TURBINES AS ENABLERS FOR A LOW OR REDUCED CARBON ENERGY ECOSYSTEM

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Dr. Jeffrey Goldmeer
Schenectady, NY, USA 12345

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ABSTRACT

The desire to reduce carbon emissions from traditional power generation assets is driving an increase in power production from renewables. However, an issue with large increases in renewable power generation is the lack of dispatchability; without adding storage or firming capability increases in renewables can strain a power grid. Gas turbines can be used to fill this gap, but there are questions about the long-term use of these assets in a carbon-free energy ecosystem.

An advantage for gas turbines is that they are able to operate on hydrogen, which does not provide any carbon emissions when combusted. This includes both new gas turbine and existing units which can be converted to operation on a high H_2 fuel.

This paper will provide an update on how gas turbines can support a low or reduced carbon electrical grid by operating on a wide variety of lower carbon fuels, including current hydrogen capabilities of GE gas turbines, requirements for upgrading existing turbines for operation on hydrogen fuels, and potential future technology options.

INTRODUCTION

The desire to reduce carbon emissions from power generation is creating a fundamental paradigm shift in the power generation industry. A direct result of this shift is an acceleration in the installed capacity of renewable power sources, including solar and wind. For example, ~86% or 21 GW of the new power installations in Europe in 2016 were from renewable sources[1]. With the large and rapid increases in installed capacity of renewable sources, there are concerns about the need to dispatch large blocks of power quickly to provide grid stability given the interruptible nature of some renewables. In these situations, grid regulating agencies used dispatchable power generation assets (i.e. gas turbine power plants) to balance supply and demand.

Although these assets are dispatchable and needed for grid regulation, there are questions being asked about utilization of these plants in a potential future, carbon-free energy ecosystem. There are multiple approaches for low carbon or carbon-free fuels, including the use of hydrogen (H_2) for power generation[2]. Modern gas turbines are capable of operating on a wide range of H_2 concentrations, with multiple commercial power plants having considerable experience. Thus, gas turbines operating on hydrogen could provide the needed grid firming while at the same time generating significantly less carbon dioxide emissions.

In a reduced or carbon-free energy ecosystem that relies on H_2 for power generation, the fuel will have to be generated in large volumes. There are technologies available today that can generate H_2, including electrolysis of water. (Hydrogen generated from renewable sources is being called "green hydrogen".) Electrolysis of water requires a large amount of energy, which could dramatically increase the cost of the hydrogen. A potential solution is available, in part, due to the fundamental paradigm shift: the rapid increase in installed capacity of renewable sources is creating excess power, leading to curtailment and, in some situations, even negative electricity prices. Using curtailed power from renewable sources could potentially supply the power needed to generate H_2; Figure 1 illustrates the concept of how a *power to hydrogen* system could be part of a reduced carbon energy ecosystem.

This paper will examine the concept of power to hydrogen in the context of using gas turbines as an enabler for a reduced carbon (or carbon-free) energy ecosystem.

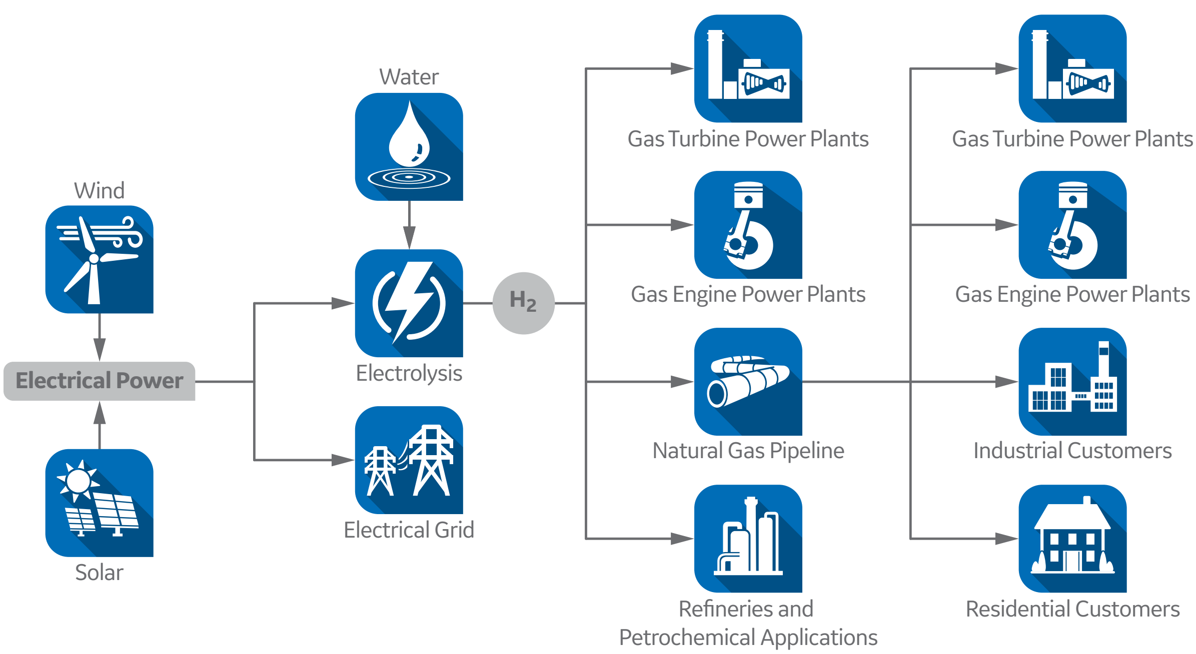

Figure 1: *Power to hydrogen* energy ecosystem concept.

POWER TO HYDROGEN

Hydrogen can be generated from a variety of feedstocks and chemical processes, as shown in Figure 2. These include (but are not limited to) photosynthesis using algae, steam methane reforming of natural gas, partial oxidation of crude oil, gasification of coal, and electrolysis of water. In the current context, using a fossil fuel as a feedstock is less desirable as it generates carbon dioxide as part of the process[3]. Therefore, many groups are examining the potential of using renewable sources of energy to produce hydrogen, while others are already building or running small scale projects.

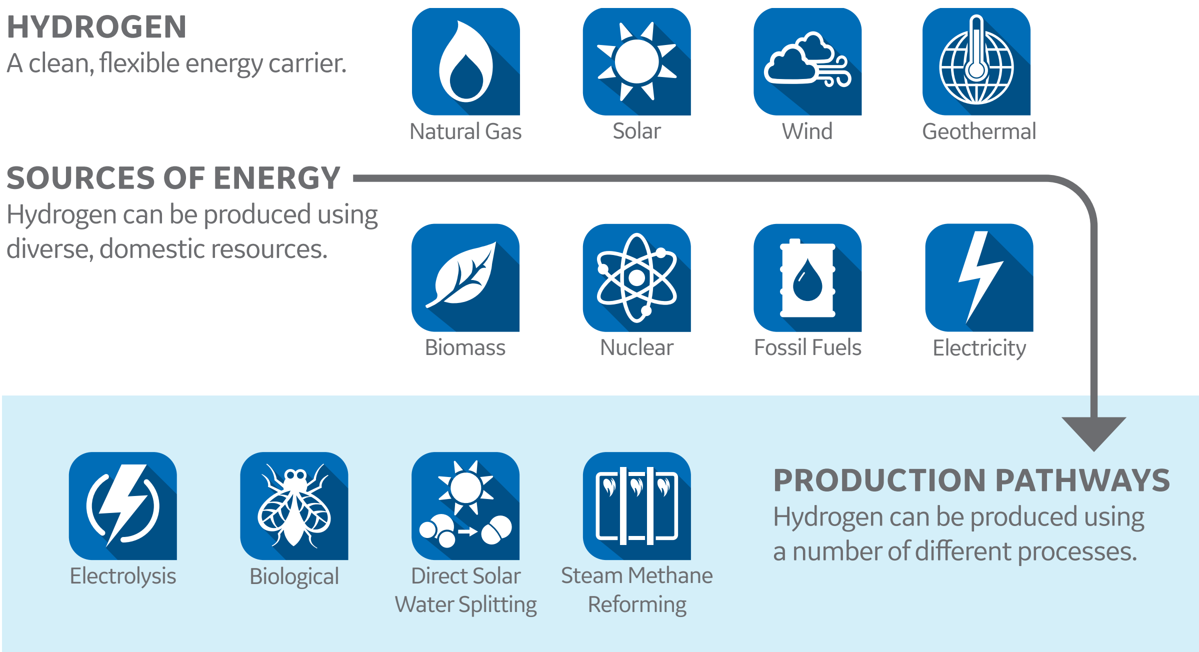

Figure 2: Pathways to hydrogen[4].

Studies on the potential for *power to hydrogen* have been published by multiple groups. One report, written by Trachtabel-Engie and Hinicio, articulated that "Power-to-Hydrogen is bankable already today"[5]. This same report also noted that stacking several revenue streams (i.e. refinery applications for H_2, gas grid injection, etc.) can de-risk the business case and are "an effective way to achieve profitability".

Part of the process for evaluating the technical and economic feasibility of the *power to hydrogen* concept is in building and scaling up systems. The US National Renewable Energy Lab is demonstrating the technical feasibility for power to hydrogen with an integration of wind turbines, photovoltaic arrays, and an electrolyzer system to generate hydrogen[6]. ITM Power has multiple small-scale installations in Europe that are already providing hydrogen for power from renewable energy sources; in one case the hydrogen is injected into the local gas distribution network, and in the other it is stored and used with fuel cell to provide back-up power[7,8]. In addition, the Australian Renewable Energy Agency (ARENA) is planning a trial of a new electrolysis system in the city of Adelaide; the hydrogen generated from the electrolyzers will be injected into the city's gas distribution network[9]. Long-term goals are to use renewables power for electrolysis to generate hydrogen for export[10].

Given the interest in generating hydrogen from renewables, this section will focus on key technical aspects of a power to hydrogen system.

Generating hydrogen: electrolysis of water

One established method for generating hydrogen is electrolysis of water. Splitting water follows the following chemical reaction:

$$H_2O \longrightarrow H_2 + \tfrac{1}{2}\, O_2 \qquad (1)$$

Based on this reaction for each mole of water used, 1 mole of hydrogen and one-half mole of oxygen are generated. Using the molecular weights listed in Table 1, each gram of water used will generate 0.11 grams of hydrogen and 0.89 grams of oxygen. (Notice that the total mass is conserved.) In other words, generating 1 gram (1 kg) of hydrogen requires 9 grams (9 kg) of water, assuming no losses in the electrolysis process.

Table 1: Molecular weight of water, oxygen, and hydrogen.

	Formula	**Molecular Weight** (grams/mole)
Oxygen	O_2	32
Hydrogen	H_2	2
Water	H_2O	18

With this information, it is possible to compute the water required to support the power to hydrogen concept. Table 2 shows the water required to generate sufficient hydrogen to operate four different gas turbines on 100% hydrogen. For reference, an Olympic-size swimming pool contains 2500 m3 of water; this means that an electrolyzer generating hydrogen for a GE-10 would use an equivalent volume of water in approximately 250 hours (just over 10 days). Supplying hydrogen for a 9F.04 would use an Olympic pool of water every 12 hours.

Operating a gas turbine on a hydrogen/natural gas blend instead of 100% hydrogen reduces not only the hydrogen flows, but the amount of water required to generate the hydrogen. Table 2 also includes flows rates operating the same gas turbines on a 5% (by volume) blend of hydrogen and natural gas. (Note that the values are not simply scaled; the calculations account for the required heat input for the gas turbine.)

Table 2: Flow rates for 100% hydrogen operation.

Gas Turbine	**Output†** MW	**Heat Rate†** GJ/hour (MMBTU/hour)	**100% H_2 Flow Rate** m^3/hour (ft^3/hour)	**Water for 100% H_2 Operation** m^3/hour (gallons/hour)	**H_2 Flow Rate for 5% Blend** m^3/hour (ft^3/hour)	**Water to Support 5% H_2 Blend** m^3/hour (gallons/hour)
GE-10	11.2	129 (122)	~11,700 (~446,000)	~10 (~3,700)	~190 (~6,680)	~0.15 (~40)
TM2500	34.3	350 (332)	~31,800 (~1,210,800)	~27 (~7,300)	~510 (~18,130)	~0.40 (~110)
6B.03	44.0	473 (448)	~ 43,000 (~1,635,900)	~37 (~9,900)	~690 (~24,500)	~0.53 (~148)
9F.04	288	2,677 (2,537)	~243,500 (~9,266,900)	~212 (~56,000)	~3,930 (~138,740)	~3.2 (~840)

† ISO conditions operating on natural gas

Electrolysis also requires electrical power to split apart the water molecules. The amount of power required is defined by the higher heating value (HHV) of hydrogen divided by the electrolyzer system efficiency[11]:

$$\text{“Electrolyzer Power”} = HHV/\eta \qquad (2)$$

The HHV for hydrogen is 12,756.2 kJ/Nm^3 (141,829.6 kJ/kg); this is equivalent to 3.54 kWh/Nm^3 (39.39 kWh/kg). Assuming a 65% efficiency electrolyzer system, which represents commercially available technology, transforming water to hydrogen requires 5.45 kWh/m^3 (60.61 kWh/kg). Using the GE-10 gas turbine as an example, per Table 2 the hydrogen flow rate is ~11,700 m^3/ hour. To generate enough H_2 to operate the GE-10 for 24 hours, the electrolyzer system would consume ~1.54 GWh of electricity. Increasing the electrolyzer efficiency will reduce some of the power needs, as would operating the gas turbine on a blend of hydrogen and natural gas.

Thus, large sources of power and water will be required to create a hydrogen ecosystem using electrolysis of water. The next section examines the availability of renewable power to support this concept.

Renewable power for hydrogen generation

To support the concept of power to hydrogen, a large amount of carbon free power will be required. The good news is that the global drive for carbon-free power has led to an unprecedented acceleration in power production from renewables; this is evident in statistics on power generated from renewable sources. As shown in Figure 3, the electricity generated in Europe from renewables, including wind and solar, increased from ~12.6 terawatt hours (TWh) in 1990 to more than 570 TWh in 2016[12].

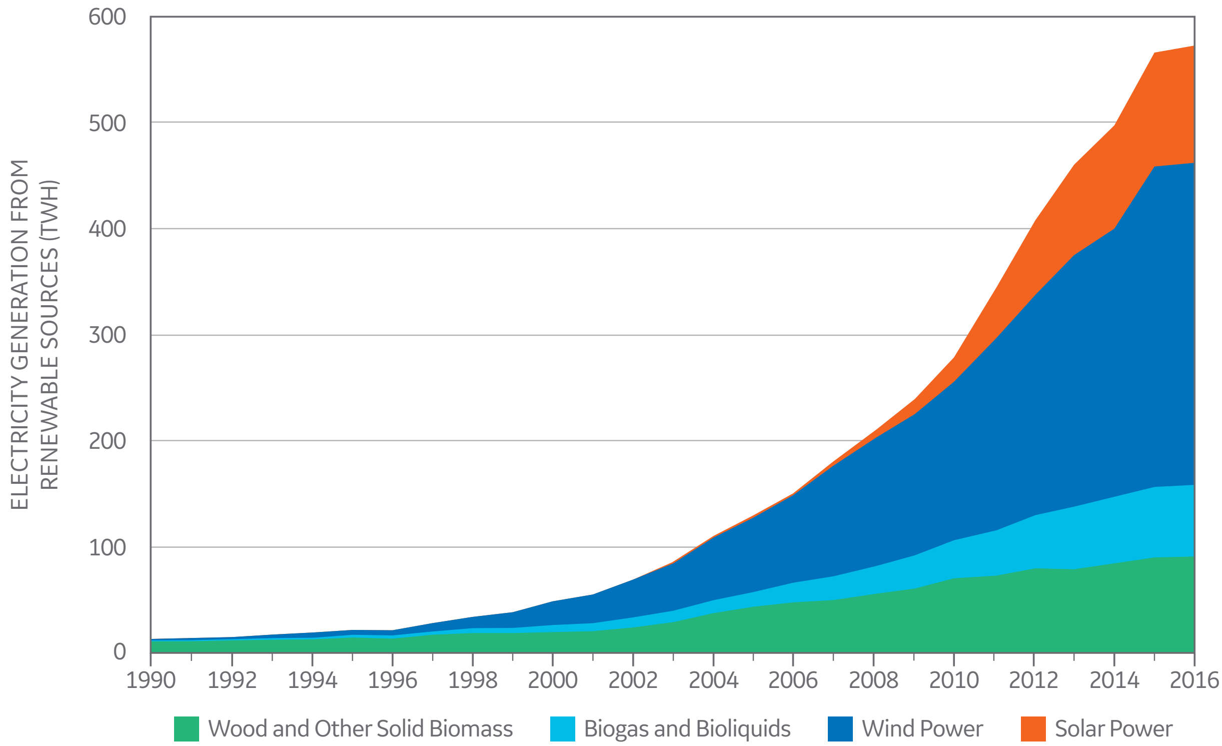

Figure 3: Electricity generation from renewable sources in Europe (TWh)[12].

Not only was the total (or absolute) amount of power from renewable sources increasing, but the percentage of power from renewable sources relative to total power on the grid was also increasing. Table 3 shows the growth in renewables in multiple countries in Europe between 2004 and 2016. It is interesting to note that many of the counties with the smallest increase in renewable penetration (i.e. Iceland, Sweden, and Norway) already had high rates of electricity generated from renewable sources in 2004. This growth in installed renewable capacity continued in 2017; according to Wind Europe, an additional 6 GW of solar along with 15.6 GW of wind power were installed in 2017. The installed wind power capacity in Europe is now estimated at 169 GW[13].

A key to using renewable sources to generate hydrogen is having excess power, above and beyond that which is needed for electrical demand. One way to gauge this capability is with curtailment of renewable sources. Table 4 shows wind curtailment for Germany, Ireland, Italy, and the UK between 2012 and 2016; data was not available for all countries in all years. As seen in the table, there are stark differences between the wind curtailed in these countries; Germany had the largest amount of curtailed power of the countries listed, with the smallest amount of curtailment existing in Ireland and Italy.

Given the significant growth in the installed base of renewable power sources, there is potential to use excess renewables to support some level of a power to hydrogen system. If this happens, there are benefits to utilizing hydrogen as a combustion fuel, namely a reduction in carbon emissions.

Table 3: Increase in share of energy from renewable sources[12].

Country	2004 Share (%)	2016 Share (%)	Percent Growth in Renewables 2004-2016
United Kingdom	1.1	9.3	745%
Netherlands	2.0	6.0	200%
Italy	6.3	17.4	176%
Germany	5.8	14.8	155%
Denmark	14.9	32.2	116%
Spain	8.4	17.3	106%
France	9.5	16.0	68%
Iceland	58.9	72.6	23%
Sweden	38.7	53.8	39%
Norway	58.1	69.4	19%

Table 4: Curtailed wind power (GWh)[12].

Country	2012	2013	2014	2015	2016
Germany	410	358	480	3,743	4,722
Ireland	103	171	236		
Italy	164	106	119		
United Kingdom	45	380	659	1,277	

CARBON EMISSION REDUCTION WITH HYDROGEN

Hydrogen (H_2) is a clean burning fuel that does not produce any carbon emissions as it does not include any carbon (C). In a complete and balanced combustion reaction, which is the opposite of splitting water (Equation 1), the only product is water:

$$H_2 + \tfrac{1}{2} O_2 \rightarrow H_2O \qquad (3)$$

Using 100% hydrogen as fuel for a gas turbine will lead to a significant reduction carbon dioxide (CO_2) emissions relative to operation on natural gas or other hydrocarbon fuels. CO_2 emissions attributed to the fuel will be zero, although the plant will still emit a very small amount of CO_2 as there is approximately 0.04% (by volume) CO_2 in the air that will be emitted with the products of combustion. For example, a gas turbine operating on 100% (by volume) H_2 fuel will see a CO_2 reduction of ~99% relative to the CO_2 emission on 100% methane.

There are also cases where H_2 blending with natural gas is being considered to reduce CO_2 emissions as a near-term alternative to operating on 100% natural gas. In these cases, the amount of CO_2 reduction will be a function of the percentage of H_2 in the fuel. The amount or percent H_2 in the fuel can be measured on a volume, mass, or heat input basis. There is a significant difference in the H_2 flows based on these methods due to the difference between hydrogen's energy density on a mass and volume basis as shown in Table 5.

Table 5: Comparison of fuel properties.

Property	Units	Methane	Hydrogen
Formula		CH_4	H_2
Molecular Weight	gram/mol	16	2
LHV	MJ/Nm^3	35.8	10.8
LHV	MJ/kg	50	120

Typically, flows into a gas turbine are quoted on a volumetric basis, but the key factor in determining emissions for a fuel blend is the relative heat input from the fuel constituents, especially as methane and hydrogen have very different energy densities. This is an important distinction as adding small amounts of hydrogen to the fuel (on a volumetric basis) will have a smaller impact on carbon dioxide emission reduction.

The relationship between the amount of H_2 in the fuel (by volume) and CO_2 emission reduction as shown in figure 4 is clearly non-linear. The gas turbine requires a constant heat input, and since H_2 has a lower volumetric energy density, a blend on a heat input basis contains less hydrogen (relative to a blend on a volumetric basis). As an example, a 9F.04 gas turbine operating on methane at ISO conditions will emit ~38.8 kg/sec (~86 pounds/sec) of CO_2. Switching this turbine to fuel that is a 5% / 95% (by volume) blend of hydrogen and methane requires the same heat input, but due to the difference between mass and volumetric energy density of hydrogen, this ends up as a 0.65% / 99.35% blend of hydrogen and methane on a heat input basis. This results in a CO_2 emission of ~38.2 kg/second (~84.3 pounds/sec), which is roughly a reduction of ~1.5% in CO_2 emissions. Taking this one step further, to attain a 50% reduction in CO_2 emissions a blend that is ~75% (by volume) hydrogen would be required.

Instead, if the flows are set as a percentage of the turbine heat input, the relationship between H_2 and CO_2 reduction is linear as shown in Figure 5. To attain a 50% reduction in CO_2 emissions requires a blend that is 50% hydrogen and 50% methane (by heat content).

Understanding the magnitude of CO_2 emission reduction relative to H_2 content in the fuel is a key step in evaluating the value of a potential *power to hydrogen* system. However, one must also understand the technical challenges that accompany the use of hydrogen.

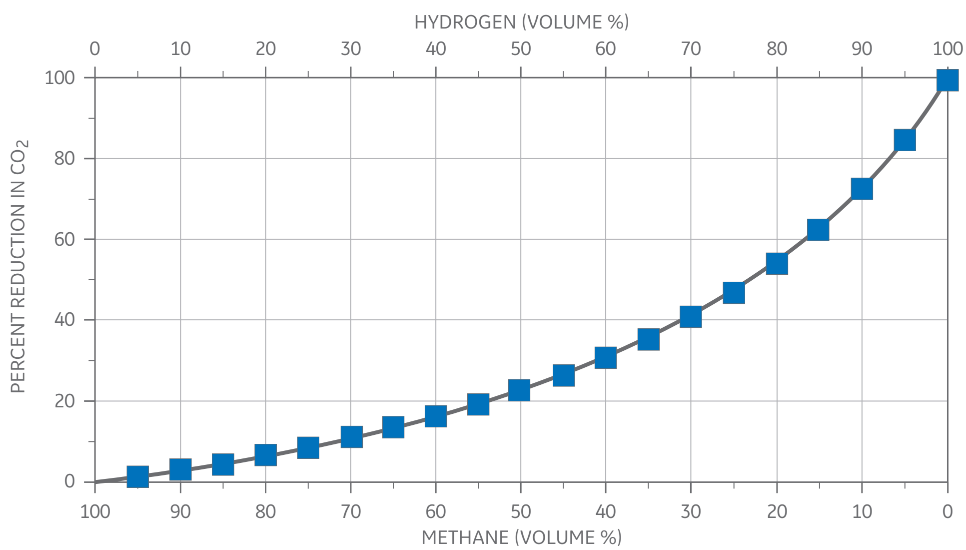

Figure 4: Relationship between CO_2 emissions and hydrogen/methane fuel blends (volume %).

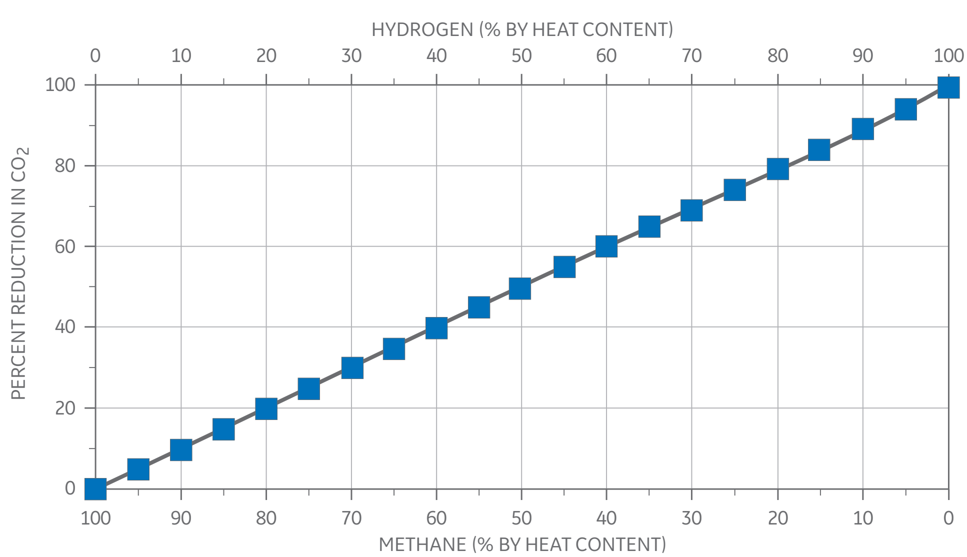

Figure 5: Relationship between CO_2 emissions and hydrogen/methane fuel blends (% heat input).

THE CHALLENGES OF HYDROGEN

Although operating on hydrogen can lead to lower CO_2 emissions, there are challenges that need to be understood given the differences between hydrogen and many traditional hydrocarbon fuels. This section provides a summary of some key combustion issues.

Heating value

The lower heating value (LHV) of hydrogen (as was shown in Table 5) is 10.8 MJ/Nm^3 (274.7 BTU/scf) or 120 MJ/kg (51,593 BTU/lb). In comparison, the LHV of 100% methane is 35.8 MJ/Nm^3 (911.6 BTU/scf) or 50 MJ/kg (21,515 BTU/lb). On a mass basis, hydrogen is 2x more energy dense that methane. But, on a volume basis, hydrogen is one-third less energy dense than methane. Therefore, it takes 3x more volumetric flow of hydrogen to provide the same heat (energy) input as methane. Thus, operating a gas turbine on 100% hydrogen requires a fuel accessory system configured for the required flow rates.

Flame speed

In a combustion reaction, the flame velocity or flame speed is the velocity at which the unburned gases propagate into the flame. The flame speed of hydrogen is an order of magnitude faster than many hydrocarbon fuels. Table 6 lists the flame speeds for a set of common hydrocarbon fuels.

From a gas turbine perspective, flame speed is an important property used in determining if a combustor will have issues with the flame propagating upstream from the combustion zone into the premixing zone (near the fuel nozzles). Once the flame has entered the premixing zone, one of two phenomena may occur. If the flame's presence in this region is transient, and the flame quickly returns to the main section of the combustor, this is called flash back. If instead, the flame anchors in the premixing zone and does not recede, this is labeled as flame holding. Depending on the fuel, duration and frequency of the events, flame holding and flashback can be serious combustion events that may damage hardware. Operating with a fuel that is outside of the OEMs' fuel specification may lead to a flash back or flame holding event. An example of damage to a dry low NO_X (DLN) fuel nozzle attributed to flame flashback is shown in Figure 6.

Table 6: Laminar flame speed of common fuels[14].

Fuel	Formula	Laminar Flame Speed (cm/sec) at Stoichiometric Conditions
Hydrogen	H_2	170
Methane	CH_4	38.3
Ethane	C_2H_6	40.6
Propane	C_3H_8	42.3
Carbon Monoxide	CO	58.8

Figure 6: Flashback damage to a fuel nozzle[15].

Typically, combustion systems are configured to operate on a set of fuels that have a defined range of flame speeds. Due to the significant difference in the flame speeds of methane and hydrogen, combustion systems configured for operating on methane (or natural gas) may not be suitable for operating on a high hydrogen fuel. In many cases, operating on a high hydrogen fuel requires a combustor specifically configured for the different combustion conditions. (See Combustion Technology section.)

Safety

There are additional operational challenges with hydrogen that relate to overall safety. First, a hydrogen flame has low luminosity and is therefore hard to see visually. This requires flame detection systems specifically configured for hydrogen flames. Secondly, hydrogen can diffuse through seals that would be considered airtight or impermeable to other gases. Therefore, traditional sealing systems used with natural gas may need to be replaced with welded connections or other appropriate components. In addition, there may be other plant level safety issues that merit review[16].

GAS TURBINE COMBUSTION TECHNOLOGY

The ability of gas turbine to operate on a high hydrogen fuel requires a combustion system that can deal with the specific challenges of this fuel. Typical DLN combustion systems can handle some amounts of hydrogen, but due the fundamental differences between hydrogen and methane previously discussed, these combustion systems are not able to handle moderate to high levels of hydrogen. Instead, combustion systems that are configured to operate on fuels with higher concentrations of hydrogen are utilized. GE offers combustion systems for both aeroderivative and heavy-duty gas turbines that are capable of operating with increased levels of H_2. The various combustion systems capable of handling higher concentrations of H_2 are shown in Figure 7.

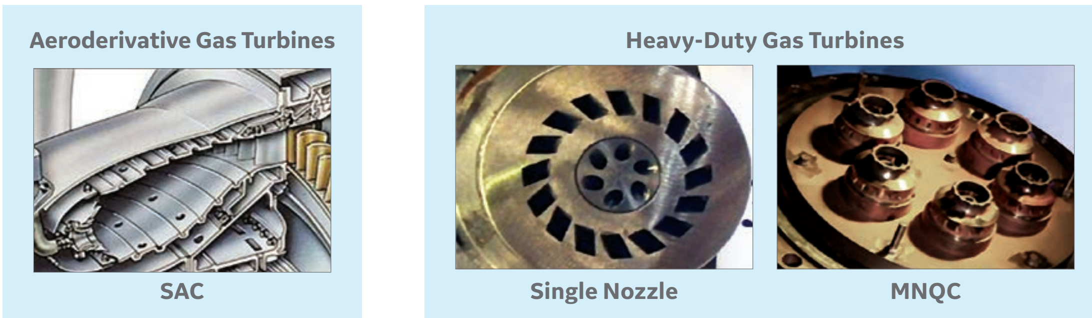

Figure 7: High hydrogen combustion systems.

Single annular combustor
GE's aeroderivative gas turbines can be configured with a single annular combustor (SAC), which can operate on a variety of fuels, including process fuels and fuel blends with hydrogen. There are over 2,500 gas turbines configured with this combustion system; these units have accumulated more than 96 million fired hours on a variety of fuels.

Single nozzle and multi nozzle combustors
GE's heavy-duty gas turbines have two combustor configurations capable of operating on fuels with higher H_2 content. The single nozzle (SN) or standard combustor is available on B and E-class turbines. The Multi-Nozzle Quiet Combustor (MNQC) is available on E-class (except for 6B) and F-class gas turbines. Combined these combustion systems have been installed on more than 1,700 gas turbines, and have accumulated more than 3.5 million fired hours on a variety of low calorific value fuels, including syngas, steel mill gases, refinery gases, etc.

During the 1990's GE evaluated the use of the MNQC combustor to operate on high hydrogen fuels[17]. The hydrogen concentration of the fuels examined ranged from ~43.5% up to ~89%; the remaining constituents in the fuel were inert gases, i.e. nitrogen and water vapor. The program evaluated the impact on NO_X emissions, combustion dynamics and combustion metal temperatures. The test results demonstrated the feasibility of burning hydrogen as the only combustible (up to 90% by volume of the total fuel) in GE's MNQC combustion system.

Next generation high H_2 combustion system
As part of the US Department of Energy's Advanced IGCC/Hydrogen Gas Turbine program†, GE developed a low NO_X hydrogen combustion system. This new combustion system was based on the operating principle of small scale jet-in-crossflow mixing of the fuel and air streams[18]. The miniaturized tubes (see Figure 8A) function as "fast" mixers enabling premixed combustion for gaseous fuels with higher reactivity (ethane, propane, hydrogen, etc.)[19]. During this program, multiple pre-mixing configurations were tested at the GE Global Research Center single nozzle facility as well as in GE's Gas Turbine Technology Lab; Figure 8B shows combustor chamber with multi-tube mixers operating on a H_2/N_2 fuel blend. Due to the advanced premixing capability of this technology, it became an element of GE's DLN 2.6e combustion system, which is available on the 9HA gas turbine[19].

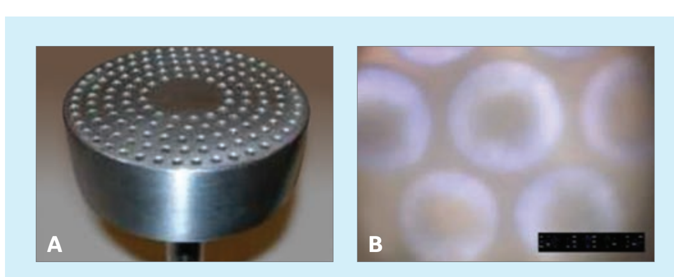

Figure 8: (A) multi-tube mixer concept hardware, (B) combustor test of multi-tube mixers on a H_2/N_2 fuel blend[18].

With these combustion systems, GE's power generation products can support the use of hydrogen in a variety of applications.

† This effort was sponsored by the US Department of Energy under Cooperative Agreement DE-FC26-05NT42564.

POWER GENERATION EXPERIENCE WITH HYDROGEN

Once hydrogen has been generated it can be utilized as a power generation fuel. There are multiple systems capable of operating on hydrogen providing power solutions a range of outputs. GE's power generation portfolio includes multiple platforms capable of operating on hydrogen, including reciprocating (gas) engines and gas turbines, supporting a range of customer power requirements.

Reciprocating (gas) engines

Although the main focus of this paper is on gas turbines, it is important to note that internal combustion engines, also known as reciprocating engines can burn a wide variety fuels[20-22]. GE's gas engines are capable of burning all kinds of non-natural gas fuels from low calorific gases all the way to gases with a high hydrogen content. Current field engines are running with a controlled hydrogen content up to 70 volume %, while in the future it should be possible to run gas engines even with 100 volume % hydrogen. Operation on hydrogen containing fuels requires a specific engine configuration with controlled fuel blending.

PROCESS GAS

A number of industrial processes yield waste or by-product gases containing hydrogen that can be used in reciprocating engines. For example, 12 Jenbacher type JGS 316 engines have been operating on coke oven gas (COG) at the Profusa Coke Factory in Spain since 1995[23]; the units have accumulated over one million operating hours. A second example is a wood gas project in Austria, where one Jenbacher 612 genset was operating on a fuel that contained 35-45 volume % H2 (by volume)[24].

HYDROGEN FROM WIND

Demonstrating the concept of "green hydrogen", a power plant in Patagonia (Argentina) uses wind power to generate hydrogen via electrolysis; see Figure 9. This plant, which was commissioned in 2009, blends the hydrogen with natural gas; the hydrogen content in the fuel blend varies from 0% to ~42% (by volume). The blended gas is used in a GE J420 gas engine to produce ~ 1.4 MW of electrical power[25, 26].

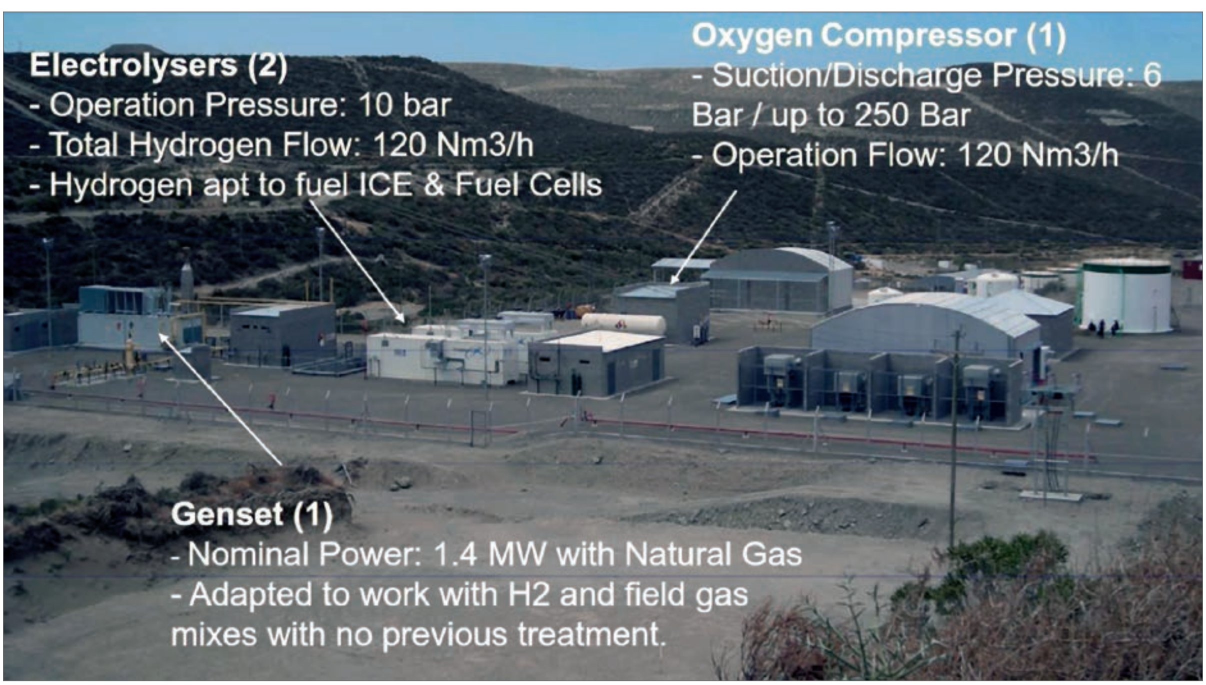

Figure 9: Hydrogen power plant – general view[26].

Gas turbines

Gas turbines have the capability to operate on hydrogen, supporting a variety of industrial applications, including steel mills, refineries, and petrochemical plants. Figure 10 highlights multiple projects that have used fuels with varying concentrations of hydrogen over the last 20+ years. The following sections provide more details on some of these projects. Additional details can also be found in papers by Jones, et al. (2011, 2013)[27, 28] and DiCampli[29].

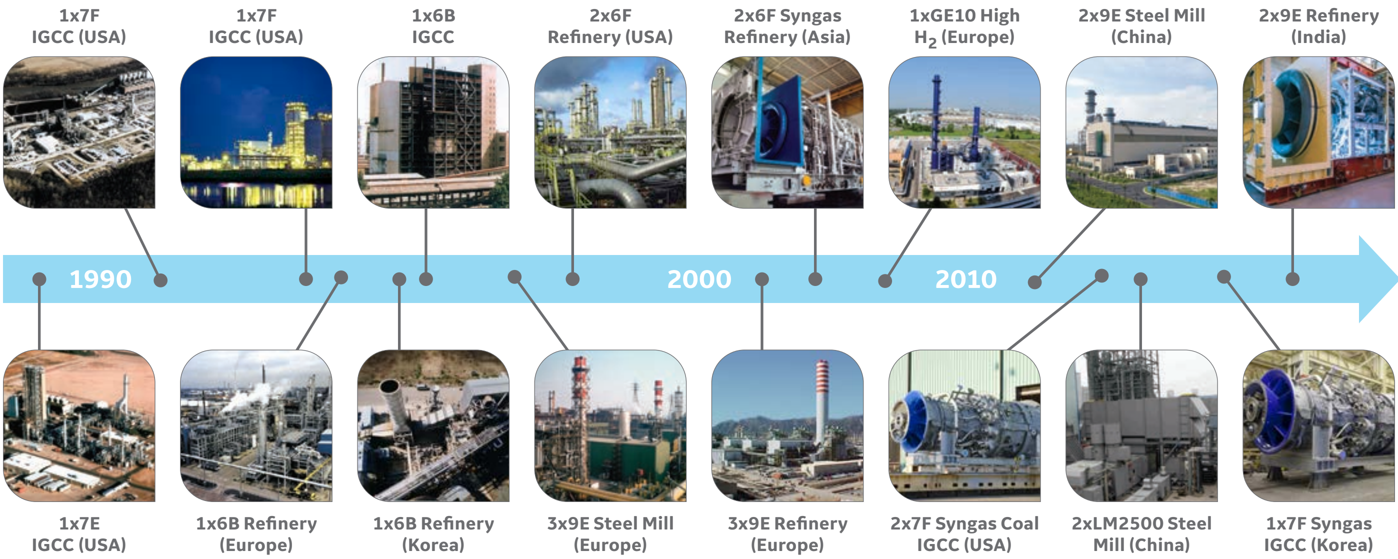

Figure 10: Timeline of projects with hydrogen fuels.

HYDROGEN FUEL BLENDING

There are circumstances when hydrogen is available as a by-product of an industrial or petrochemical process. But in some situations, there may not be enough hydrogen to fully load a gas turbine, so a blend of hydrogen and natural gas is generated; in these cases, traditional dry low NO_X (DLN) combustion systems can be utilized. One example of this fuel blending application was at the Dow Plaquemine plant in the USA[30]. At this site, hydrogen was injected into natural gas to create a 5% / 95% (by volume) blend of hydrogen and natural gas. Figure 11 shows the blending system; after blending the fuel gas was fed to four GE 7FA gas turbines configured with DLN 2.6 combustion systems. Operation on the blended fuel started in 2010.

A second example of hydrogen fuel blending is at the Gibraltar-San Roque refinery owned by Compañia Española de Petróleos (CEPSA), one of Spain's leading petrochemical companies. At this site a 6B.03 gas turbine is operating on a refinery fuel gas (RFG) that contains a varying amount of hydrogen. If the hydrogen level exceeds ~32% (by volume) the RFG is blended with natural gas. As of 2015, this gas turbine had operated more than 9,000 hours on this fuel[31].

Figure 11: Hydrogen / natural gas blending system.

LOW CALORIFIC VALUE FUELS: STEEL MILL GASES

Steel mills produce a variety of low calorific value by-product gases, i.e. blast furnace gas (BFG) and coke oven gas (COG), that have varying amounts of hydrogen. GE has multiple heavy-duty and gas turbines operating on these fuels. Examples include multiple steel mills in Asia using COG / BFG fuel blends in GE 9E.03 gas turbines[32, 33]; Figure 12A is an example of a steel mill configured with a GE gas turbine. GE's aeroderivative gas turbines can also operate on coke oven gas[34]; an example of the latter case is set of LM2500+ turbines operating on a coke oven gas (COG) with approximately 60% (by volume) hydrogen (see Figure 12B). These units were commissioned in 2011 and have accumulated over 100,000 hours on COG. Combined, GE's aeroderivative and heavy-duty gas turbines have accumulated more than one million fired hours with steel mill gases.

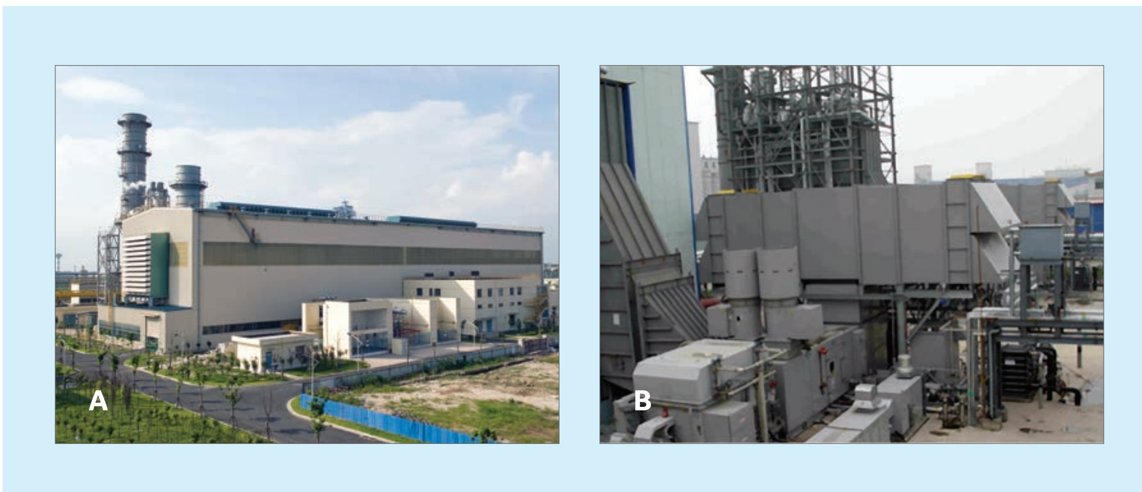

Figure 12: (A) Frame 9E.03 operating on steel mill gases at a plant in China; (B) LM2500+ operating on high H_2 coke oven gas.

LOW CALORIFIC VALUE FUELS: SYNTHESIS GASES (SYNGAS)

The use of gasification creates a fuel known as synthesis gas (syngas) that contains a variety of gases, including hydrogen. The H_2 content in these fuels can range from 20% to ~50% (by volume) depending on the feedstock (i.e. coal, refinery bottoms) and the gasification process. Multiple IGCC (integrated gasification combined cycle) plants utilizing E-class and F-class gas turbines are in commercial operation globally. Plants with GE gas turbines have accumulated more than 1.5 million operating hours. This includes the Tampa Electric Polk Power Station, Duke Edwardsport IGCC plant, and the Korea Western Power (KOWEPO) TaeAn IGCC plant.

HIGH HYDROGEN

Typically, when H_2 is available in large volumes it is used in hydrotreating crude oil or in the production of other commercial products, such as fertilizers. However, there are instances where a large volume of high concentration hydrogen is available from a process where there are no other available off takers. One example of this is the Daesan refinery in South Korea. This location has a 6B.03 gas turbine (Figure 13) that has operated on a fuel that contains more than 70% (by volume) hydrogen for over 20 years with max H_2 levels greater than 90%[35]. To date the unit has accumulated more than 100,000 hours on the high hydrogen fuel. A second example of a high hydrogen turbine is at Enel's Fusina, Italy. This plant, which was inaugurated in 2010, used a GE-10 gas turbine to produce ~11.4 MW of net electrical power operating on a fuel that was ~97.5% (by volume) hydrogen[36, 37].

Figure 13: High hydrogen fueled 6B.03 gas turbine.

CONVERSION TO HIGH H_2 FUELS

When considering a power to hydrogen system, existing gas turbine assets should be included as part of the evaluation as they can be converted to operation on fuels with hydrogen. An advantage to gas turbines is that they can be re-configured for operation on new fuels, including fuels with increased levels of hydrogen fuels.

When considering a change to a fuel with increased levels of hydrogen, the scope of the conversion will be a function of the amount of hydrogen in the fuel. If the new fuel will be a blend of hydrogen in natural gas, the required changes might be limited controls updates along with new combustor fuel nozzles. As examples, the Dow and CEPSA cases highlighted earlier involved fuel conversions which included changes to the existing combustion systems. Given that there are many variations on fuel, combustor configurations, etc., the required scope would have to be evaluated on a case by case basis.

If the conversion is to a high hydrogen fuel, the scope could include changes to numerous gas turbine systems as shown in Figure 14. This type of fuel conversion may require switching to a new combustion system, which would require new fuel accessory piping and valves. It may also require new fuel skids, as well as enclosure and ventilation system modifications. Some of these changes are necessitated by the safety concerns highlighted previously. Aside from physical changes, this would require changes to the gas turbine controls, which might impact gas turbine performance, both output and heat rate.

Regardless of the fuel, when considering a fuel conversion, there are other factors that should be evaluated; these include but are not limited to site emission limits, fuel storage, and local safety regulations.

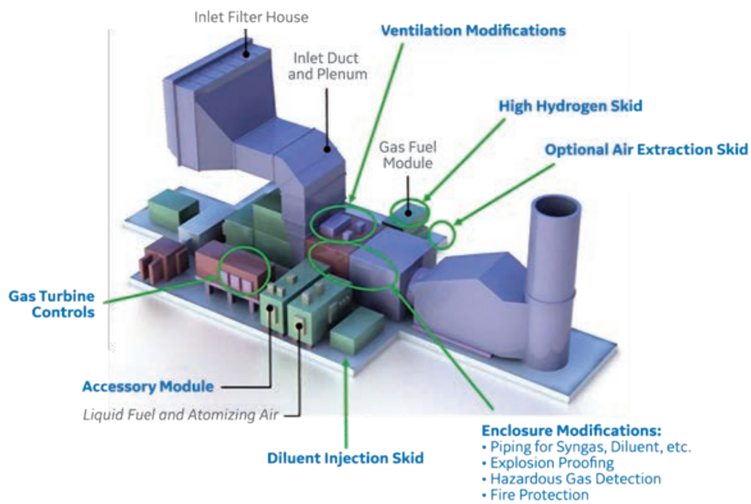

Figure 14: Impact of hydrogen fuel conversion on gas turbine systems.

CONCLUSION / SUMMARY

Gas turbines are capable of operating on a wide variety of fuels, including fuels with low, moderate, and high levels of hydrogen. Given the experience in the industry with hydrogen-based fuels, many of the technical questions on the viability of this fuel for power generation applications have been answered. Thus, existing gas turbine power plants should be considered a key element of any future power to hydrogen ecosystem.

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