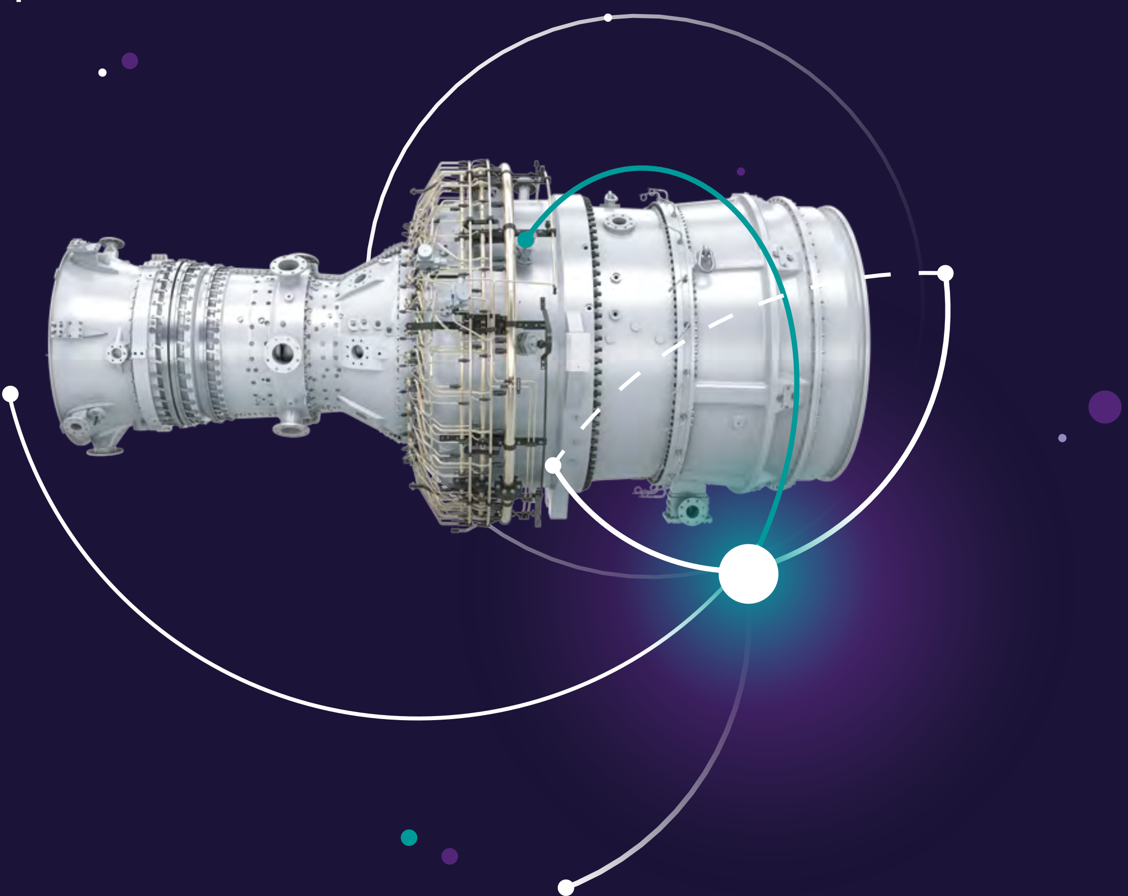
SIEMENS energy

Decarbonization pathways for gas turbines

White paper



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Foreword

We have a long history with gas turbines that goes all the way back to the 1940s. In 1961, our VM 80 unit at the Obersendling combined heat and power plant in Munich set a record as the world's highest performance single-shaft gas turbine. In the decades that followed we continued to make strides in gas turbine technology – pioneering efficient and reliable turbines for power generation and enabling widespread electrification of communities around the world.

Today, our portfolio includes world-class gas turbines in the power range from 2 to 593 MW, with diverse applications such as distributed power generation, mechanical drive units for compressor stations on gas pipelines, combined cycle power plants, and combined heat and power units that are essential to energy systems.

On the way to a fully decarbonized world, the energy landscape will continue to rely on gas turbines to provide uninterrupted power and compensate for the intermittency of renewables. While modern, highly efficient and flexible combined cycle gas power plants are increasingly substituting coal power plants (reducing CO_2 emissions by up to 65% already), we need to take further steps to decarbonize gas turbines in the near- to mid-future. Several technologies are either available in the market or being developed, from carbon capture, utilization and storage (CCUS) to the use of sustainable fuels such as hydrogen, biofuels or hydrogen derivatives.

At Siemens Energy, we are working together with our customers to find new ways to meet the demands of today, while future-proofing our turbines for tomorrow. Major successes have already been achieved in the form of several engine tests firing sustainable fuels. In 2023, we had a significant milestone for hydrogen-capable turbines: Together with the HYFLEXPOWER consortium, a team of Siemens Energy experts, industry, and university partners, we celebrated the successful test of a 13 MW SGT-400 gas turbine powered by 100% green hydrogen in DLE mode. We have also carried out successful tests with other sustainable fuels such as HVO and methanol.

We also know that there is so much more that can be done. And that is exactly what we aim to explore in this white paper, which outlines the role of decarbonized gas turbines in a future energy landscape, in power grids increasingly dominated by intermittent renewables, where covering the residual load and keeping the grid system stable will become the most important challenges to meet. Several options are available, so the route to decarbonization is not one, but there are many different paths, with local conditions playing a big role in answering the question of which technology will prevail at which site. In all cases, Siemens Energy is dedicated to providing solutions and technologies that will realize the shared objective of protecting our planet for the generations to come.

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Executive summary

A rapid expansion of renewable energy has taken place in recent years and must accelerate even further to satisfy rising energy demand while meeting global carbon-reduction targets. Wind and solar – the leading renewable sources – are inherently intermittent. Their variability creates residual load gaps, heightens the need for ancillary grid services, and raises the risk of power shortfalls, particularly in winter when PV generation is low. Seasonal fluctuations and more frequent extreme-weather events compound the challenge. Consequently, retiring unabated fossil-fueled plants must coincide with the introduction of flexible, dispatchable, and sustainable generation to complement wind and solar.

Gas turbines are, and will remain, integral to the energy system. They combine low capital cost, high efficiency in combined-cycle configurations, long operating life, rapid responsiveness to demand swings, and the capability to supply ancillary grid services. In combined heat-and-power (CHP) schemes they also cover essential heat demand, especially in winter.

Decarbonization of gas turbines can be pursued via use of a sustainable fuel or via carbon capture and utilization / storage (CCUS). Among the 'drop-in' sustainable fuels are:

- Hydrogen: green hydrogen from renewable-powered electrolysis; blue hydrogen from steam methane reforming with carbon capture; turquoise hydrogen via methane pyrolysis; pink hydrogen from nuclear-powered electrolysis; and white hydrogen from naturally forming deposits in the earth´s crust.

- Synthetic fuels produced from sustainable hydrogen (RFNBOs / e-fuels), such as e-methanol and e-ammonia. Hydrocarbon-based e-fuels like methanol must employ CO_2 from sustainable sources to be considered sustainable themselves.

- Biogenic fuels, e.g., biodiesels (HVO, FAME), biomethanol, or bioethanol. Growing production of sustainable aviation fuel (SAF) from biogenic feedstocks could also benefit some land-based turbines.

Fuel choice depends on several aspects such as fuel costs and availability, local factors, availability of required infrastructure, primary / backup fuel considerations and the expected operational regime. Requirements for gas turbine and plant modifications, supply and storage aspects may result. Sustainable hydrogen has emerged as a frontrunner for gas turbine applications in several regions – Siemens Energy has demonstrated dry-low-emissions combustion of 100 percent green hydrogen in a commercial 13 MW SGT-400 CHP plant, with larger frames such as the SGT-800 and SGT-9000HL next in line for 100% H_2 development. Ammonia offers high potential as a carbon-free, large-scale and long-distance energy vector owing to its energy density, established handling practice, and mature transport technology. Efficient cracking processes and system integration in case of cracked ammonia combustion are pivotal because cracker cost and footprint affect feasibility, efficiency, and flexibility. Siemens Energy and academic partners are advancing combustion of fully cracked, partially cracked, and direct-fired ammonia.

Sustainable methanol (e- and biomethanol) is another key player. Often an intermediate product for other chemical products and e-fuels, it provides cost and availability benefits and suits diverse turbine applications, including marine propulsion and liquid storage on site.

The other main decarbonization option, integrating carbon capture with gas turbines is possible through pre-combustion capture, oxy-fuel firing, or post-combustion capture (with either absorption or adsorption technology). Low CO_2 concentrations in turbine exhausts increases efforts for post combustion CCS; countermeasures include exhaust-gas recirculation, oxygen injection, and emerging technologies such as electro-swing absorption. As with alternative fuels, techno-economic factors (mainly driven by local conditions) will dictate adoption rates.

Abbreviations

ATR	Autothermal Reforming
BECCS	Biomass Energy Carbon Capture and Storage
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CC(U)S	Carbon Capture (Utilization) and Storage
CFD	Computational Fluid Dynamics
CHP	Combined Heat and Power
DAC	Direct Air Capture
DCC	Direct Contact Cooler
DLE	Dry Low Emissions
DME	Dimethyl Ether
DSM	Demand Side Management / Response
EHS	Environment, Health, and Safety
EGR	Exhaust Gas Recirculation
FAME	Fatty Acid Methyl Ester
GHG	Greenhouse Gases
GWP	Global Warming Potential
HPC	Hot Potassium Carbonate
HRSG	Heat Recovery Steam Generator
HVDC	High Voltage Direct Current
HVO	Hydrotreated Vegetable Oil
IPP	Independent Power Producer
IRR	Internal Rate of Return
KPI	Key Performance Indicator
KVV	Kraft- och Värmeverk (CHP plant)
LCOE	Levelized Cost of Electricity
LHV	Lower Heating Value
LPG	Liquified Petroleum Gas
MOF	Metallic-organic framework
NG	Natural Gas
NPV	Net Present Value
OEM	Original Equipment Manufacturer
OPEX	Operational Expenditure
PCC	Post Combustion Capture
RES	Renewable Energy Sources
RFNBO	Renewable Fuel of non-biological Origin
RNG	Renewable Natural Gas
SAF	Sustainable Aviation Fuel
SMR	Steam Methane Reforming
TRL	Technology Readiness Level

1 The role of gas turbines in the future energy landscape

1.1 Introduction

Tackling global warming is one of the most important and urgent challenges for society today. The significant increase in greenhouse gas (GHG) emissions over the last two centuries has already increased global temperatures since the pre-industrial era by around 1.1 °C [1], with the rate of change of temperature being faster than in any other historical period. If global warming continues to increase as predicted, e.g. up to 2.9 °C above pre-industrial levels by the end of the century compared to the internationally agreed limit of 1.5 °C, then there will be devastating consequences due to extreme weather events, rising sea levels, loss of species, etc. The economies of countries will also be affected – costs associated with dealing with irreversible climate change will most likely exceed the costs required to limit it in the first place. Currently carbon dioxide (CO_2) emissions from fossil fuels and industry contribute 67% of GHG emissions based on 100-year global warming potentials (GWP) [2]. Of these, around 40% of CO_2 emissions are due to the power sector and around 25% due to heating (both for buildings and process heat).

"We will not be able to contain the global warming below 1.5 degrees in the next few years. Overshooting is now inevitable. However, if leaders start taking the problem seriously by driving towards net zero greenhouse gas emissions, the 1.5 °C target remains – according to all the scientists I met – possible before the end of the century."

António Guterres, Secretary-General of the UN

Statements and calls from politicians, business leaders and researchers reflect increasing public awareness about the imminent threat of climate change and the need for a rapid global transition to renewable energy sources (RES). This white paper examines the future expansion of RES in electric grids and its impact on the 'energy trilemma' faced by policymakers: security of supply, affordability and sustainability. Thanks to their inherent fuel flexibility, gas turbines will play a central role in the energy transition [3] whether firing a sustainable fuel such as hydrogen, biogenic fuels or hydrogen derivatives, or fossil fuels with carbon capture utilization and storage (CCUS). As described in the following sections, technology development at Siemens Energy is ongoing on many different fronts that represent the most promising routes to decarbonization [4].

1.2 Expansion of renewables

Wind and solar – today's fastest-growing RES technologies – are intermittent. Consequently, the power system and wholesale electricity markets must evolve to manage an ever-increasing amount of these intermittent energy sources at large scale [5]. In an energy system dominated by RES, closing the residual load gap in a sustainable manner becomes fundamental.

Closing the residual load gap

At present, the residual load is covered by fossil power plants (coal and gas) and reservoir hydro, often combined with run-of-river hydro and nuclear power as baseload capacity. In future, with widespread adoption of RES, the residual load will be characterized by strong seasonal fluctuations of RES power supply, occasional oversupply of power and persistent residual load events that may last up to several weeks. Germany's four-week long "dark doldrum" event in January-February 2017 with barely any wind and solar power exemplify the challenge [6]. In a projected scenario with 86 percent RES share, identical weather conditions would still yield a large continuous and fluctuating residual load (Figure 2). In addition, climate experts predict an increased number of persistent weather events, so that residual load events between 4 and 6 weeks will have to be considered in designing the electrical grid system [7].

Cross-border electricity imports help only where sufficient interconnections exist. However, the meteorological conditions that cause residual load events are likely to affect neighboring countries at the same time, with very limited surplus energy available for export – if at all. While High Voltage Direct Current (HVDC) connections over long distances (>1,500 km) may alleviate the issue, this will still not be sufficient – as demonstrated by a modelling exercise that assumed unlimited, direct and lossless power exchange between EU countries: In such cases, there was still a significant uncovered residual load demand [8].

Demand-side management (DSM) can reduce the load gap but is not yet deployed on a significant scale. DSM requires technical readiness and effective price signals to influence

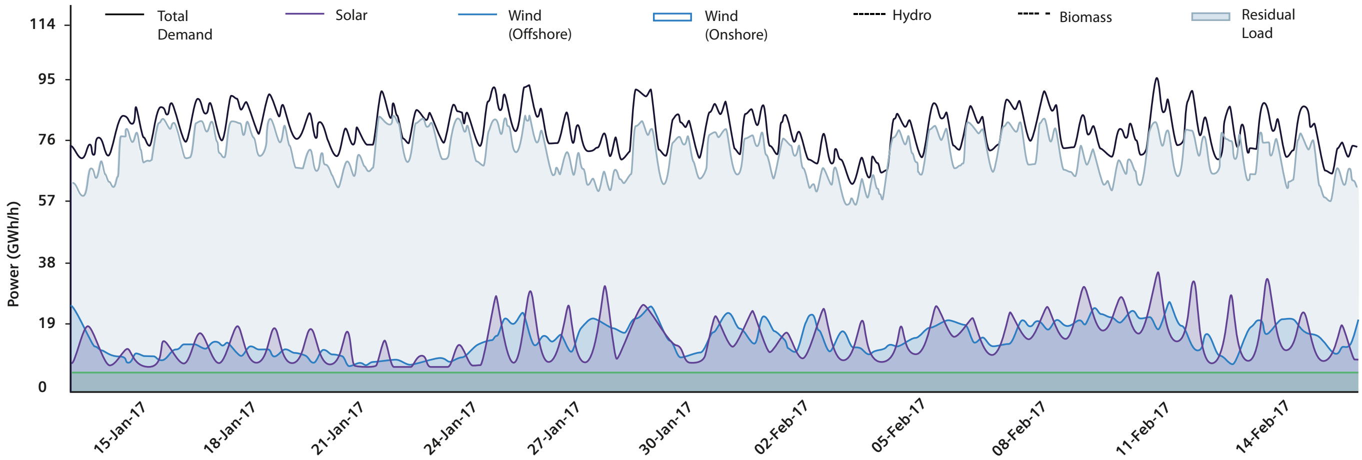

Figure 1: Power generation and consumption in Germany, January to February 2017.[6]

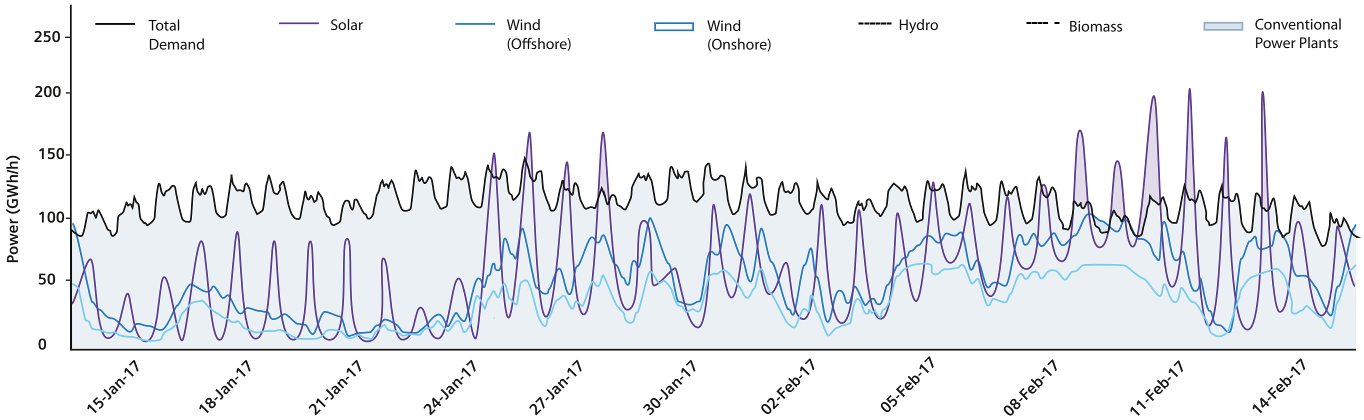

Figure 2: Future power generation and consumption assuming 86% renewables share (cf. **Figure 1**)

consumer behavior. It is most applicable to non-critical loads and does usually allow load shifts within a day, but does not solve residual-load events exceeding 24 hours or even seasonal imbalances.

Another option to cover the residual load is energy storage, for which several technologies are available covering time-scales from seconds (flywheels and supercapacitors), hours (batteries and pumped hydro), to a few days (compressed air energy storage). However, all these technologies are neither technically nor economically suited to bridge multi-week power deficits. Decarbonized, efficient, and flexible gas turbines that utilize chemical storage (power-to-X) will therefore be indispensable complements to RES.

Ancillary grid services

Grid services that ensure the safe, stable distribution of electricity are: Reactive power and voltage control; frequency control; provision of inertia and short circuit power; and black start capability. Today nearly all of these are provided for free by centralized generation facilities (coal, gas, hydro and nuclear) that have large synchronous generators.

With the ongoing expansion of RES in the form of wind power (mostly as direct drive units with frequency inverters) and solar power (PV modules also connected through inverters), many of these older centralized units are being retired. At times of the year when wind and solar will meet the total power demand, the remaining centralized generation assets may not always be synchronized with the grid, reducing the number of synchronous generators connected to the grid. Modern wind turbines and PV modules cannot provide all ancillary grid services due to their technical design features. The importance of this issue to the smooth operation of future electricity grids is compounded by changes on the demand side that are expected to increase the necessity for robust ancillary services: increased number of static frequency converters, fewer synchronous motors connected to the grid, further reducing system inertia, and a massive increase of arc furnaces in the metals industry that will make the load side more unstable.

Batteries connected to the grid (assuming that they are sufficiently charged, but not to full capacity, as sufficient capacity uptake is always required to allow absorption of sudden excess power) can help to provide some, but not all the ancillary services required. Therefore, the availability of large synchronous generators connected to the grid will continue to be mandatory. This can happen either by provision of dedicated synchronous condensers or via self-synchronizing clutches between gas / steam turbines and their generators, allowing gas turbine power plants to stay connected to the grid even at times when there is no residual load demand and the turbine is not in operation. Furthermore, flywheels can be added on the generator side to increase the rotating inertia even more.

Residual heat demand

In an energy system with a large share of intermittent RES, periods of residual load often coincide with high heating demand, when there is also a shortfall of power to run heat pumps and electric furnaces, i.e. residual load and residual heat events are often concurrent. This is especially critical in wintertime in regions that have the highest demand for heating of buildings, usually in latitudes above 35°, where also PV potential is very low in winter times. During such periods, gas turbines and combined heat and power (CHP) plants can fill the gaps, providing both residual power and heat. By utilizing heat storage in the form of hot water, power and heat production can be decoupled. Then CHP plants may follow the electricity market – providing residual load – while also supplying district heating networks and industrial processes. The energy utilization rate of CHP plants is very high, reaching up to 85–90%, making them the most attractive way to cover residual heat demand in such situations.

1.3 Decarbonization of gas turbines

In order to achieve either full decarbonization or carbon neutrality of gas turbines, two main transformation routes appear possible: Operation with a decarbonized or carbon-neutral fuel (called 'sustainable fuel' throughout this paper); or continued operation with fossil fuel, e.g. natural gas, but coupled to a form of either Pre- or Post-Combustion Carbon Capture (CCUS). As shown in Figure 3, sustainable fuels can be hydrogen (H_2), H_2 derivatives (often also referred to as e-fuels, synthetic fuels or RFNBOs – Renewable Fuels of non-biological origin), or gaseous or liquid biofuels. Most relevant e-fuels are e-ammonia (NH_3) produced from sustainable hydrogen via the Haber–Bosch process, or hydrocarbon fuels that are produced from H_2 and sustainable CO_2, where the CO_2 is obtained e.g. from direct air capture (DAC) or CCU at a biomass power plant.

Since many sectors are currently undergoing rapid change, the development of decarbonized gas turbines offers new

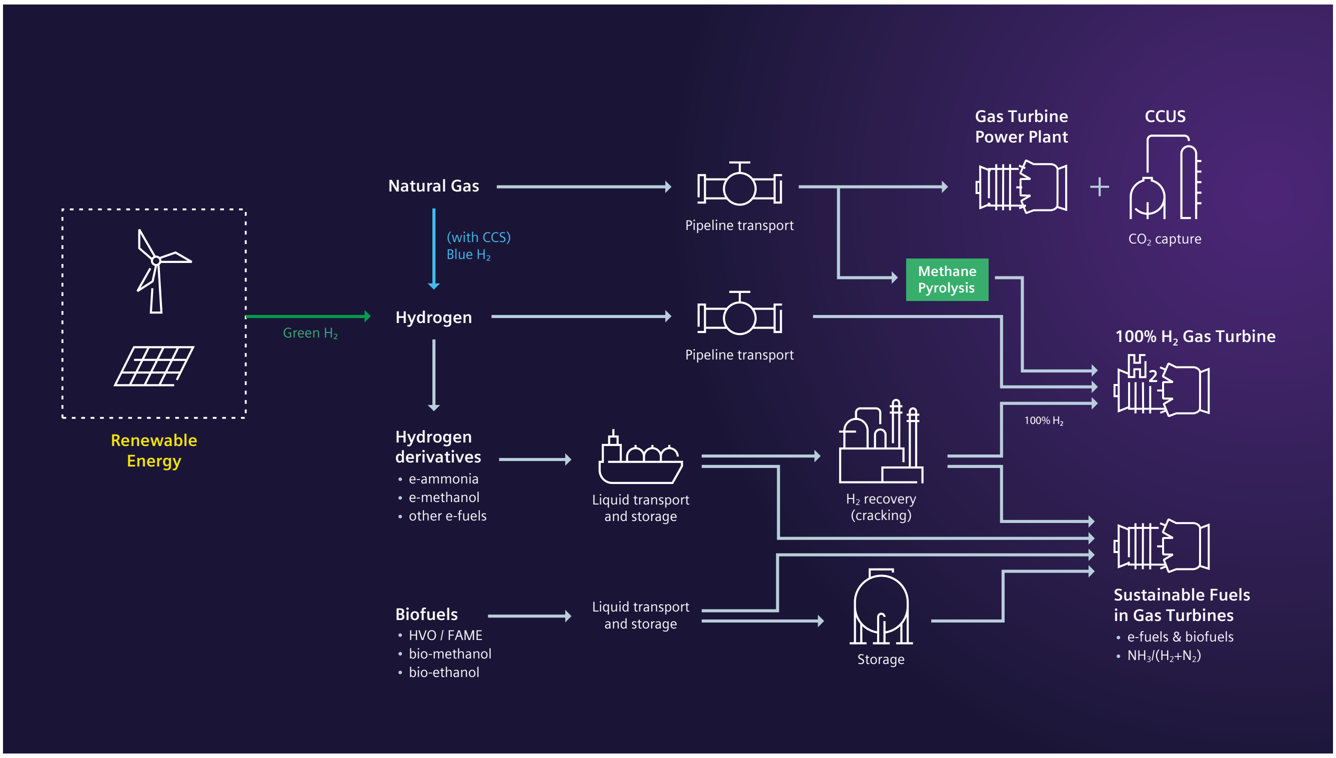

Figure 3: Decarbonizing residual load in an RES-based energy system

opportunities. For example, the marine industry has ambitious targets for the decarbonization of international deep-sea shipping [9] and is considering the same candidate fuels as in Figure 3. In this case electric propulsion for marine applications powered by a combined cycle gas turbine (CCGT) can be competitive with reciprocating IC engines.

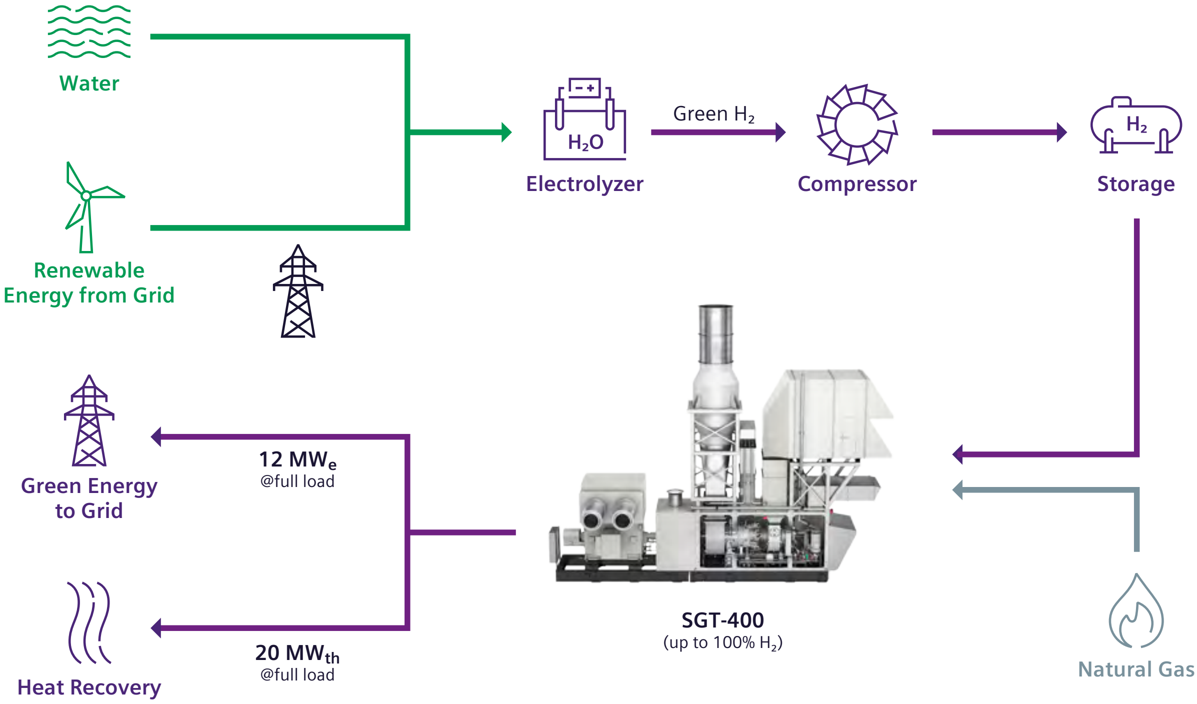

Figure 4: Power-to-H_2-to-power, as studied by the HYFLEXPOWER consortium

2 Sustainable gaseous fuels

2.1 Hydrogen

In recent years, sustainable hydrogen (H_2) has emerged as a prime candidate for decarbonizing the power sector. Major gas-turbine manufacturers, including Siemens Energy, have publicly committed to 100 % H_2 capability by 2030 [10]. The principal technical hurdles arise from H_2 combustion properties – much lower ignition energy, higher flame speed, and wider flammability limits compared with natural gas – necessitating bespoke burner designs and optimized control strategies.

Sources and colors of hydrogen:

- **Green H_2:** Produced from renewable-energy sources (RES) via electrolysis.
- **Blue H_2:** Steam-methane reforming of natural gas with carbon capture and storage (CCS).
- **Turquoise H_2:** Pyrolysis of natural gas, yielding hydrogen and solid carbon for disposal instead of CO_2
- **Pink H_2:** Produced from nuclear electricity via electrolysis.
- **White H_2:** Naturally occurring underground accumulations currently under exploration; their commercial viability remains uncertain but promising. Upstream hydrogen extraction, cleaning and transport to the main consumer points will be the main challenges in making white hydrogen available to energy clients.

Figure 5: Installation of SGT-400 core engine at the HYFLEX-POWER demonstration plant in Saillat-sur-Vienne in France

Infrastructure and costs

Electrolyzers will generally be located close to RES generation, after which H_2 is transported by pipeline to load centers like cities and industrial complexes. Increased H_2 production volumes are achieved when electrolysis is carried out close to RES sites, minimizing electricity transport losses. Transporting molecules is also cheaper than transporting electrons: Depending on diameter and pressure, a single gas pipeline can carry the energy equivalent of up to 10 high-voltage transmission lines while incurring significantly lower energy consumption [13]. Because of residual load balancing requirements and due to intermittency and seasonality of RES output, large-scale storage of compressed H_2 in underground caverns will be required, so a pipeline network linking production, storage, and consumption hubs must be deployed in any case.

Round-trip efficiency from RES power-to-H_2-to-power in a combined-cycle gas turbine (CCGT) can only reach up to 35–40% under favorable conditions. Consequently, the current levelized cost of electricity (LCOE) for green H_2 is higher than for blue H_2. Nevertheless, in regions with abundant low-cost RES, pairing renewables with H_2-fired plants to cover residual load is expected to deliver the most economical path to full decarbonization. Various studies project that green H_2 costs will significantly reduce over time due to economies of scale, number and technological advancements, becoming cost-competitive with natural gas between 2035 and 2050, depending on regional electricity prices, carbon policy, and scale.

Green Hydrogen Demonstration

An integrated industrial RES power-to-H_2-to-power solution was demonstrated at a cogeneration plant by the HYFLEXPOWER project [11]. The project consortium led by Siemens Energy included ENGIE, Centrax and others and was supported by the EU Horizon 2020 programme. Siemens Energy supplied the electrolyzer for green H_2 production and developed dry low emissions (DLE) combustion technology for the SGT-400 gas turbine (Figures 4 and 5). Engine tests carried out at the customer site in Saillat-sur-Vienne in France (Figure 6) successfully

Figure 6: Cogeneration plant at Smurfit Kappa's paper mill, Saillat-sur-Vienne, where 100% H_2 operation was demonstrated

demonstrated operation with 100% H_2, natural gas and any blends thereof – a world's first for an industrial gas turbine of this size (>10 MW). Additional operational tests in 2025 and 2026 under the successor development program for this site, HyCoFlex, will expand the operational envelope of the turbine on all hydrogen blends in anticipation of a commercial Sales Release.

Siemens Energy is accelerating the development of gas turbine technology for 100% H_2 firing (including larger, heavy-duty frames) based on the findings of the engine demonstration test. For detailed information on H_2 combustion in gas turbines please refer to the detailed white paper entitled 'Hydrogen power and heat with Siemens Energy gas turbines', available via the Siemens Energy website [12].

2.2 Biogas

Biogas is the generic term for product gases from the anaerobic digestion of organic matter. Common sources are landfills, waste-water treatment plants and purpose-built biodigesters for 'wet' agricultural wastes such as crop residues and animal manure. Depending on the composition of the feedstock, biogas is typically a blend of 40–75% vol. methane (CH_4) with the remainder consisting of CO_2 and small amounts of other gases and contaminants such as H_2S or siloxanes. Biogas is suitable for power generation and cogeneration, with most applications being for small to medium size gas turbines (<50 MW). Lower Heating Values (LHV) of biogases lie in the range of 16–30 MJ / m³. Operational experience includes SGT-300 and SGT-400 firing biogas using DLE combustors, which yielded similar (or lower) NO_x emissions than natural gas. Larger frames such as the SGT-800 have been proven to operate on raw natural gas having high N_2 and CO_2 contents similar to biogas.

There are often incentives promoting the use of biogas as this avoids emissions of CO_2 and CH_4 that would otherwise occur due to natural decomposition of organic matter. Costs include pre-processing of the gas, e.g. removal of contaminants or blending of biogas with other fuels to raise the Wobbe Index (a characteristic number describing the interchangeability of different fuel gases), and sometimes also costs for transport of biomass to the site.

2.3 Renewable natural gas

Renewable Natural Gas (RNG), also known as bio-methane, is pipeline-quality renewable natural gas that is well suited to existing gas turbine combustion systems. RNG can be produced either by removing CO_2 from biogas or by gasifying 'dry' biomass such as wood wastes to create H_2 and CO followed by a methanation step. Due to the additional processing step(s) required for RNG compared to biogas its applications are largely CAPEX cost driven. Feeding RNG into the natural gas distribution network may attract tax breaks and incentives such as Renewable Certificates. While RNG is a fuel that can be combusted easily by gas turbines, RNG may have a higher economic value when compressed or liquefied, e.g. as a fuel for vehicles.

2.4 Synthetic methane

Synthetic methane, or e-methane, is produced from methanation of H_2 and CO_2, and can be burned by gas turbines without design changes. The lowest carbon footprint corresponds to green H_2 and CO_2 captured from biogenic sources or DAC. Alternatively, a gas turbine power plant using e-methane produced from green H_2 and a sustainable source of CO_2 together with CCS (see Section 4) would operate in a carbon negative manner, effectively acting as a carbon sink. Most applications for e-methane are expected to be in the chemical processing industry, e.g. as a feedstock for olefin production. E-methane offers the advantage of reusability of the natural gas infrastructure, but its disadvantages like its gaseous form (making handling, transport and storage more cumbersome) and GHG warming potential (if leaked) make this fuel less attractive in the long term. Moreover, the additional costs and efficiency losses for e-methanization make this fuel less attractive than the direct use of hydrogen. Gas turbine power plants are therefore more likely to either directly use the green H_2 or (if synthetic hydrocarbon is required) an e-fuel that is easier and cheaper to handle, transport and store such as methanol, for example (see Section 3.3).

3 Sustainable liquid fuels

3.1 Biodiesels

Biodiesels, sometimes also referred to as renewable diesels, have several advantages as fuels for gas turbines:

- Similar characteristics to conventional diesel, which has been used for decades – typically as a backup fuel for natural gas fired GTs.

- Infrastructure for transport and storage is well established. Many biodiesels are suitable for long term storage.

Whilst the EU and US are leading producers of biodiesels, high demand from other sectors (e.g. the mobility sector) is expected to limit availability for the energy sector, so that in many cases backup power plants represent the most suitable applications short term. On the long-term, biofuels will always remain limited in its availability, due to competition with food production (1st generation biofuels) and site area restrictions / limited availability of waste biomass and other 2nd generation biofuels, and therefore will not be able to fully replace conventional fuels.

Hydrotreated vegetable oil (HVO)

Hydrotreated Vegetable Oil (HVO) is produced from vegetable oils and animal fats, e.g. pine oil, slaughter waste and cooking oil. These different feedstocks provide more sustainable sourcing options for HVO than other biofuels. The GHG savings are significant: up to 93% compared to the reference value of 83.8 g CO_2e / MJ for fossil fuel, depending on the source [14]. The process of hydrogenation yields a high-quality biodiesel having properties suitable for gas turbine combustion. Moreover, it is suitable for handling and long duration storage even in colder climates.

Figure 7: SGT-800 HVO100 demonstration at Göteborg Energi's Rya KVV (CHP) facility, 2021

Siemens Energy carried out HVO demonstration tests with SGT-800 gas turbines at the Rya CHP plant in Gothenburg (Figure 7), followed by successful validation during commissioning of an SGT-800 owned by Stockholm Exergi [15]. Following additional tests, HVO100 has been released for several aeroderivative and industrial gas turbine frames in the Siemens Energy portfolio.

Fatty acid methyl esters (FAME)

Fatty Acid Methyl Esters (FAME) produced from vegetable oils, e.g. rapeseed or soybean, are the second most available biofuel after bioethanol. The quality of FAME depends on the feedstock and cleaning / refining processes. Storability is generally more limited than conventional diesel and HVO. Applications for FAME will probably depend on the ability to cope with alkali metal contaminants, which can be difficult for gas turbine combustion systems. Also, its lower lifetime and slow decomposition makes it less attractive than other biofuels, as longer-term storage in tanks is problematic.

Fischer-Tropsch diesel

Fischer-Tropsch (FT) diesel and other advanced fuels can be produced by converting syngas obtained from biomass waste, or from H_2 and a sustainable carbon source, into a raw hydrocarbon followed by refining. The biomass-to-liquid process is a promising technique to provide renewable alternatives for hard-to-decarbonize sectors. The fuel properties of FT diesels are comparable to conventional diesel and HVO, and hence suitable for combustion in gas turbines.

3.2 Ammonia

Ammonia (NH_3) can easily be liquefied by pressurization to 10 bar at 25 °C, or by cooling to -33 °C at atmospheric pressure. Consequently, liquid ammonia has advantages as an energy vector in a hydrogen economy:

- Energy density: Liquid ammonia has a higher energy density than gaseous hydrogen, making it more practical for storage and transportation.

- Lower flammability: Ammonia has a higher ignition temperature and a relatively narrow flammability range compared to many fuels, which reduces its explosion risk.

- Established technology: Synthetic ammonia is produced at scale for fertilizer, urea, and other applications. It has a proven distribution network and long-established industrial safety practices.

The state of the art for NH_3 combustion in GTs is not advanced. Fuel properties such as the laminar flame speed of ammonia (max. 7 cm / s) are very different from natural gas (37 cm / s). Additional key difficulties like high NO_x emissions generated due to fuel-bound nitrogen are highlighted by rig tests performed by Siemens Energy and SINTEF with (gaseous) CH_4 / NH_3 blends [16]. Emissions of both N_2O, which is a very potent greenhouse gas (GHG factor of around 270), and unburnt NH_3 pose challenges for combustion technology and exhaust aftertreatment. Suitable EHS provisions must be in place to prevent exposure to lethal concentrations of ammonia, e.g. as low as 5000 ppm for 5 minutes [17].

Cracked ammonia

Decomposition of NH_3 into N_2 and H_2 represents a promising route to overcoming the difficulties associated with ammonia combustion, i.e. using hydrogen as a reactivity promoter. The resulting gas from a cracking process (called "cracked ammonia") consists of a mixture of 75 % hydrogen and 25% nitrogen, with potential traces of residual ammonia. Full or partial cracking of ammonia can be achieved by:

- Catalytic cracking, typically using ruthenium or supported metal catalysts like nickel on alumina, at temperatures ranging from 400 °C to 900 °C.

- Thermal cracking, e.g. in the range 1,200 °C to 2,000 °C, where heat is used to break chemical bonds within the NH_3 molecules.

Plant footprint, CAPEX and OPEX are important factors that will influence decision-making. Siemens Energy is partnering with ammonia cracking licensing companies on the assessment of different models for cracker integration and plant operation, e.g. exchange of heat and cooling flows to recover the energy used for the cracking process and to minimize LCOE. Co-firing with cracked NH_3 is already approved for SGT-800 using up to 50:50 blends of fully cracked NH_3 and natural gas.

Techno-economic factors affecting cracked ammonia applications for power plants vary between sites, including availability of land, proximity to populated areas, which may dictate local EHS considerations with respect to ammonia handling at site and unburnt NH_3 emissions, and regional strategies for the future hydrogen economy. For example, a country like Germany that is unable to meet all its demand for power from RES can be expected to use hydrogen that is imported in the form of ammonia, and a local integration of a centralized cracker with a power plant may show beneficial. Major EU shipping terminals (Rotterdam, Hamburg, etc.) are attractive sites for centralized, near-complete cracking of NH_3 feeding into a hydrogen pipeline network that could benefit from integration within a power plant to improve overall cracking efficiency.

Especially for regions with a lack of RES capability and impossibility to get connected to a hydrogen backbone network, gas turbines running on ammonia as a fuel present a solution for the provision of residual load and grid ancillary services. On the other hand, as the combustion technology for NH_3, cracked NH_3 and blends thereof becomes more mature, decentralized, partial cracking can be considered for power stations located near the importation hubs – with smaller concentrations of molecular hydrogen acting as a reactivity promoter for GTs that burn high concentrations of NH_3.

Roadmap for ammonia combustion

Due to its inherent advantages as an energy vector, ammonia combustion is an active area of research in academia and industry. Siemens Energy is participating in several studies aimed at improving fundamental understanding of the topic and clearing the way for development of suitable technology [18]. The difficulties are non-trivial: detailed experimental data, e.g. in-flame laser diagnostic measurements, are lacking for combustion of NH_3 or NH_3 / (H_2+N_2) blends at engine relevant operating pressures >10 bar; and further work is needed to develop robust chemical kinetic mechanisms for CFD models. Theoretical studies indicate that staged combustion with relatively long residence times may yield improvements of combustor performance on NH_3 and partially cracked NH_3 / (H_2+N_2) [19]. Siemens Energy is following both combustion routes: While direct combustion promises a cost-effective approach to ammonia electrification, there are several associated challenges to it: Maintaining combustion stability, limiting NO_x emissions (due to presence of fuel-bound nitrogen), and Environment, Health, and Safety (EHS) considerations (avoidance of any unburned NH_3 emissions to the atmosphere, also under non-normal operating conditions such as trips, failed starts and flame out events). Cracked ammonia offers easier development, more stable combustion, lower EHS risks but comes at the expense of a large cracking plant which needs integration with the power plant.

3.3 Methanol

Today, methanol (CH_3OH) is primarily used as a feedstock for the chemical industry. Its main feedstock source is coal- and natural gas-derived syngas, but there is increasing interest and demand for sustainable methanol in the form of biomethanol (from biomass), or e-methanol produced from green / blue hydrogen and a sustainable carbon dioxide source. The advantages of sustainable methanol include:

- Energy density: Liquid methanol has a higher energy density than gaseous hydrogen.
- Diversity of source feedstock, e.g. biomass and waste.
- Increasing availability as other sectors (international shipping etc.) will shift to e-methanol for decarbonization.
- Compatibility with existing infrastructure: storage tanks, pipelines, and fueling stations.
- Long term storage without degradation in tanks with inert gas padding.

Many different applications are possible, from base load or as a secondary fuel for GTs, to island power plants, backup power for data centers, or remote industrial operations such as mining. Methanol is also gaining traction in the marine industry, with Maersk announcing the purchase of several methanol fueled vessels [20]. While relatively few gas turbine operators are likely to burn liquid methanol directly, there is also the possibility of using waste heat for prevaporization, e.g. for GTs that do not have liquid fuel systems. Alternatively, methanol can be reformed into hydrogen via steam-methanol reforming, similar to steam-methane reforming.

Biomethanol demonstration test

Siemens Energy and RWG successfully demonstrated bio-methanol firing on an SGT-A20 and an SGT-A35 gas turbine in Aberdeen, UK (Figure 8) [21]. Since methanol has roughly half the calorific value of diesel on a volumetric basis, appropriately up-sized fuel injectors, fuel pumps, up-sized fuel injectors and fuel delivery components were used.

Various operating modes were tested including start-up, shutdown, and transient operation. Tests in steady state yielded NO_x emissions reductions of up to 80% for methanol compared to kerosene (Figure 9[a]), with similar emissions reductions being expected relative to diesel.
The power boost of 10% (Figure 9[b]) is consistent with the increased exhaust mass flow associated with higher fuel flow and the change in exhaust gas composition. Further work will extrapolate the findings of the tests onto other frames.

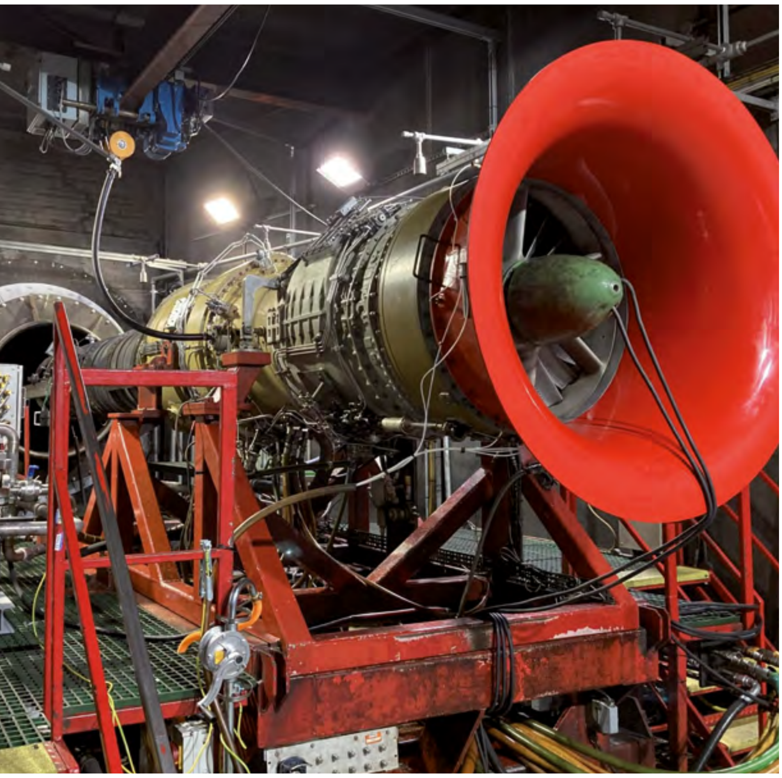

Figure 8: SGT-A20 bio-methanol demonstration test at RWG's Aberdeen test facility

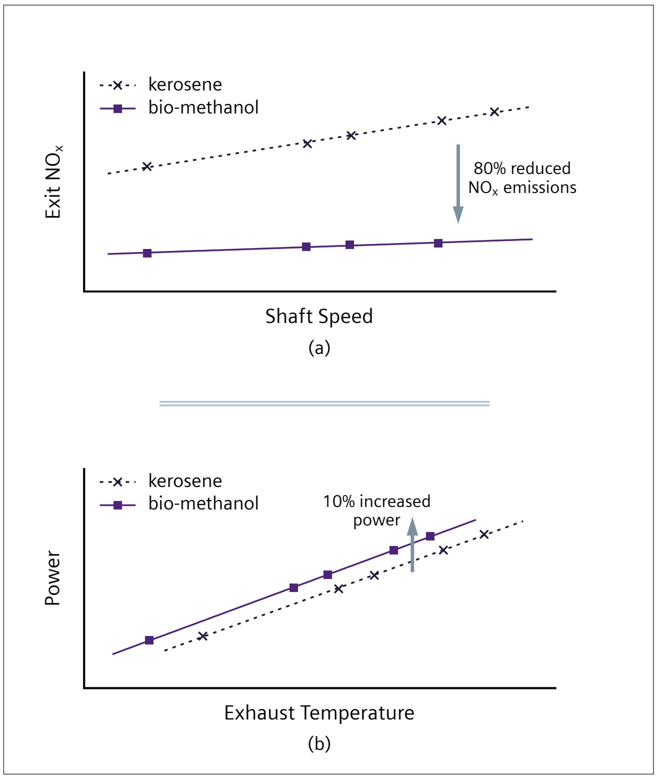

Figure 9: SGT-A20 bio-methanol demonstration test results

3.4 Ethanol

Bioethanol is currently the most widely available biofuel and can be produced from several different feedstocks – typically sugarcane in tropical climates (India, Brazil and Colombia); and corn in other areas such as China, the EU, and US [22].

These are classed as first generation biofuels and are not usually considered sustainable by regulators due to competition with food production. Second generation bioethanol is produced from non-edible lignocellulosic biomass, e.g. residues from forest management or food crop production, or whole plant biomass harvested on non-arable land. Global demand for ethanol is largely driven by government policies about gasoline-ethanol fuel blends for vehicles, whereas the long-term electrification of the transport sector could increase the availability for gas turbine applications. The e-fuel route for the production of ethanol is unlikely to become significant for gas turbines, and as e-methanol is easier to synthesize, and e-ethanol does not offer any additional advantages over e-methanol. In general, since many e-fuel production routes come via syngas or methanol it will often be cheaper to use methanol than the other 'drop-in' e-fuels.

From a gas turbine combustion point of view, it is fairly easy to develop ethanol fuel capability, its combustion characteristics being similar to methanol. With the knowledge gained in methanol development, Siemens Energy therefore started investigating ethanol combustion technology while monitoring if a viable market size develops in the industry.

3.5 Sustainable aviation fuel (SAF)

It is estimated that Sustainable Aviation Fuel (SAF, a kerosene-type hydrocarbon) could contribute up to 65% of the emissions reductions needed for aviation to reach net zero by 2050 [23]. SAF, similar to conventional gray jet fuel, is usually well suited to combustion in gas turbines, with many Siemens Energy frames already released for commercial operation with kerosene fuels. Today almost all SAF produced comes from biogenic sources, which are more mature, and cost effective compared to SAF produced as a Renewable Fuel of non-biological Origin (RFNBO), i.e. an e-fuel. Nevertheless, demand is limited by the fuel costs which are 3–4 times higher than conventional jet fuel [24]. Certification of SAF for aero engines is ongoing and increasing availability is anticipated for aviation. However, the amount of SAF available for the power sector will probably remain relatively low, especially considering that this fuel will be more expensive than a much easier to synthesize e-methanol. For non-aviation uses of SAF as fuel in gas turbines, marine applications and backup power plants represent the most likely applications.

3.6 Dimethyl ether

Dimethyl ether (DME) and its derivatives are clean-burning, non-toxic synthetic gases that can be produced from syngas or methanol (as with the other e-fuels described above). Currently, they are mostly used as aerosol propellants and in the chemical industry. Although DME is gaseous under atmospheric conditions, it is typically stored and handled as a pressurized liquid, similar to liquefied petroleum gas (LPG). DME has a high cetane number, allowing it to ignite easily and burn more completely than traditional hydrocarbon fuels. Consequently, its combustion in gas turbines can eliminate SO_x emissions and potentially reduce NO_x and particulate emissions, depending on turbine combustion design. Moreover, when produced from renewable electricity and captured CO_2, DME can be nearly carbon-neutral across its lifecycle.

Potential disadvantages for gas turbine applications include the need for modifications to the fuel system, limited supply and transport infrastructure, availability limitations, and EHS hazards, as leaks result in the rapid release of flammable gas. Material compatibility issues with seals and elastomers must also be considered. DME's lower volumetric energy density compared to traditional liquid fuels may require larger fuel storage volumes and combustion system redesign will be necessary to address high reactivity and flashback risks. Since methanol is often an intermediate step in DME synthesis, the additional processing steps introduce extra cost considerations compared to burning methanol directly. Hence, DME is unlikely to become a major gas turbine fuel, except in niche applications where surplus DME is available as a fuel.

4 Carbon capture technologies

CCUS is increasingly recognized as having a critical role to play in the delivery of net zero scenarios [25]. In the power sector, CCUS is applicable to both gas turbines as well as coal and biomass power plants. In industry, CCUS can be applied to the flue gases of hard to abate processes like cement and steel making. CCUS also provides a route for the production of blue, low-carbon hydrogen (see Figure 3). Siemens Energy has ongoing partnerships with CCUS technology providers and is also evaluating the next generation of carbon capture technologies, which are currently at lower Technology Readiness Levels (TRL). The efficiency of carbon removal via CCUS is less than 100%, and GHG emissions upstream from the site (e.g. methane leakage) must be considered. Furthermore, for a fossil power plant to be fully sustainable the carbon must not end up in the atmosphere. CO_2 storage in underground reservoirs (e.g. in depleted gas fields or deep saline aquifers) or alternative long-term, fully contained processes such as utilization in building materials, qualify as sustainable; whereas the use of fossil-derived carbon to produce synthetic fuels (e-fuels), even if part of a 'closed loop', would eventually emit at least some CO_2 into the atmosphere and is only partially sustainable.

4.1 Storage and utilization

Storage is a prerequisite for sustainable carbon capture, either directly near the site or via a pipeline to a final depository location, such as a depleted Oil & Gas reservoir or saline aquifer. Hence, the potential for application of CCS to gas turbines is highest at sites that are located nearby such infrastructure, or a CO_2 pipeline that leads to such infrastructure. Currently there is very limited CO_2 storage capacity, but increasing numbers of storage locations are being identified, mainly in the EU and US [26]. In cases where sequestration of the captured CO_2 is unfeasible, utilization may be considered. For example, the production of methanol or other fuels offers a lifecycle CO_2 reduction. Algae and other biological technologies can use CO_2 to create chemicals and foodstuffs that displace either fossil fuel usage or other environmentally unfriendly products such as soy and palm oil.

4.2 CO_2 capture technologies

Table 1 lists different categories of carbon capture technologies. There are several options for pre-combustion capture, which typically have the goal of producing carbon-free fuel from fossil fuel feedstock. Some pyrolysis techniques convert CH_4 into H_2 leaving solid carbon as the material for disposal. Then the existing natural gas transport infrastructure can be used, and thermodynamic integration of the pyrolysis process into the plant may yield an efficiency benefit compared to other CCUS technologies. Similarly, gasification of coal to yield syngas, which consists predominantly of H_2 and CO, can be followed by shift reactions and separation processes to convert the CO to CO_2 for capture and storage.

Technology	Description
Pre-combustion	Removal of carbon from fossil fuels having high CO_2 content (>20% vol.)
Oxyfuel firing	EGR and O_2 injection to achieve high CO_2 in the exhaust (>70% vol.)
Post combustion capture (PCC)	Removal of CO_2 from flue gas having CO_2 content 4–20% vol. depending on stoichiometry, EGR, etc.

Table 1: Carbon capture technologies

Oxyfuel firing yields high concentrations of CO_2 in the exhaust (without N_2) so that simple condensation of the flue gas can be used to separate CO_2 from water. In this way energy intensive chemical separation processes are avoided, but significant costs are associated with reconfiguration of the plant to accommodate the oxyfuel process, and additional energy to produce pure oxygen in an air separation unit.

Pre-combustion capture (methane pyrolysis)

Pre-combustion carbon capture focuses on generating a carbon neutral fuel prior to combustion. The most promising fuel source for this is natural gas (primarily methane [CH_4]), which is already readily available for most gas turbine locations. The energy needed to crack methane into solid carbon and gaseous hydrogen is 7.5 times less than the energy needed to crack water molecules (H_2O). There are multiple technologies to perform cracking; Thermal, thermal-catalytic, plasma, microwave, solar and others. There are also multiple companies developing these technologies, however full commercialization at the scale needed for gas turbines is not yet available. Methane pyrolysis has potentially significant advantages over other decarbonization options:

- Use of existing natural gas infrastructure, with cracking directly at the power plant site.

- Potential to supply large volumes of H_2 needed for gas turbines without requiring a dedicated hydrogen network.
- Potentially lower cost / footprint than Post Combustion Carbon Capture
- Low / no water is needed with this process, only heat is required.
- Generating additional revenues from the sale of solid carbon (batteries, tires, asphalt, concrete, roofing, etc.).
- Easy handling of solid carbon (4,200 times lower volume, 3.7 times lower mass compared to CO_2).
- Potential availability of Government incentives for H_2 production, carbon capture or critical raw materials (graphite, carbon black, carbon fiber, etc.).

As companies scale these technologies, enhancing the processes, catalysts, and efficiencies, methane pyrolysis may become one of the leading methods to decarbonize gas turbines, especially for those locations with low natural gas prices and higher capacity factors. Many companies have pilot projects in development around the globe, however countries with low natural gas prices, existing gas infrastructure and significant government incentives / CO_2 regulations will have a clear advantage in the coming years to bring this into the mainstream market.

Post combustion capture

The relatively low CO_2 concentrations in the exhaust during normal operation of gas turbines, ~4% vol., pose some challenges for Post Combustion Capture (PCC) that can be addressed in various different ways. Absorption and adsorption (Figure 10) form the bases of the leading technologies.

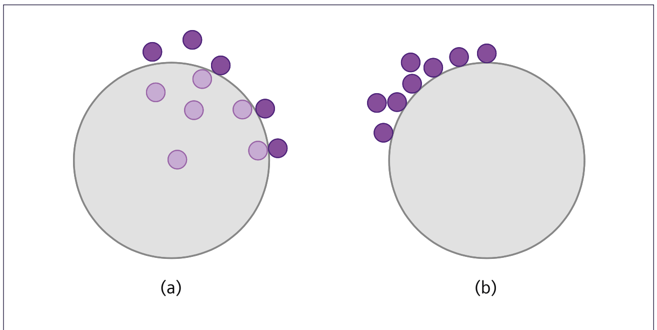

Figure 10: Molecular interactions: (a) absorption, (b) adsorption

Amine absorption can remove more than 95% of the CO_2 from the exhaust gas and may be scaled to almost any size (Figure 11), even for large gas turbines and combined cycle power plants [27]. CO_2 capture capacities exceeding 1 Mt per year are achievable, although the largest systems have

Figure 11: Typical installation of a PCC unit at a large CCGT power plant

long construction times, typically 24–36 months. Most designs consist of a tall absorber vessel, or tower, in which the CO_2-rich flue gas and the solvent flow counter-directionally. The solvent reacts only with CO_2, removing it from the gas stream. The cleaned (CO_2-lean) flue gas is released into the atmosphere while the solvent passes into a desorber tower where temperature and / or pressure changes cause the solvent to expel CO_2 that is captured, then the solvent is recirculated to the absorber vessel.

Rotating packed beds are a recently introduced PCC concept, where instead of towers the absorption and desorption processes take place in rotating drums using a proprietary amine solvent. This 'concentrated' PCC process enables a significant space saving, with footprints 50% or less compared to conventional amine tower solutions. Currently, the amount of CO_2 that can be captured is limited to ~180 kt per year, making this technology best suited to small / medium gas turbines.

Unlike amine-based technology, which is typically limited to gas temperatures around 40 °C prior to the absorber vessel, the Hot Potassium Carbonate (HPC) process accepts gas temperatures up to 700 °C making it ideal for open cycle GTs. It can also be applied to combined cycle and cogeneration units with stack gas temperatures in the range 80–180 °C. HPC solutions are currently applied to relatively smaller scale plants than amine absorption. Future development may include scaling-up to larger applications with a 800 kt per year BECCS plant in Sweden being the first step on this journey.

The HPC process pressurizes the hot flue gases using a compressor / expander configuration (Figure 12), whereby

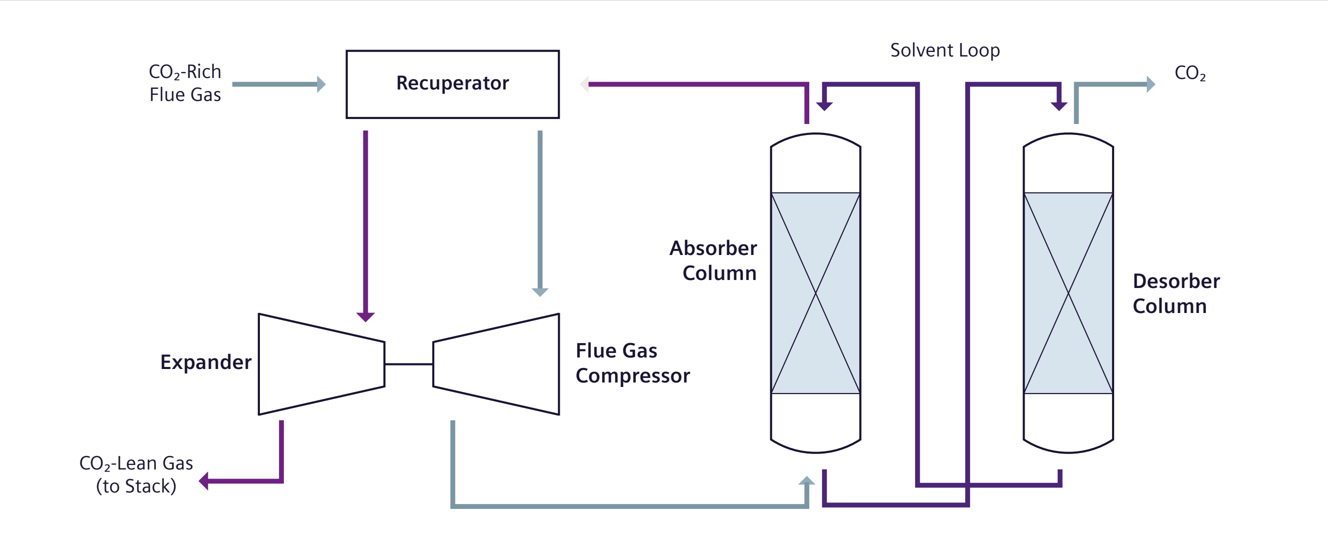

Figure 12: Simplified flow diagram of the Hot Potassium Carbonate (HPC) process

heat is extracted from the flue gas prior to the compressor to produce steam needed for solvent desorption, before passing the high-pressure flue gas through the absorber column. The expander can generate electricity using (reheated) CO_2-lean flue gas after the absorber. For open cycle GTs, the expander can generate all the electrical energy needed for the CO_2 capture process and sometimes also generate surplus electricity.

In adsorption processes the CO_2 molecules pass through a packed bed and adhere to the surface of the adsorbent. Adsorption-based systems have multiple vessels with CO_2-rich flue gas directed to 'active' vessels for CO_2 capture, while (steam) heat is applied to 'inactive' vessels for desorption / CO_2 release. Zeolites, carbon-based materials and amine impregnated chemicals are commonly used as adsorbents, although there is also increasing interest in metal-organic frameworks (MOFs). Adsorption works best at lower flue gas pressures and temperatures (40–60 °C) similar to amine absorption, while sorbent regeneration typically requires slightly higher temperatures than for amines. Current experience of adsorption-based PCC is limited to small scale applications.

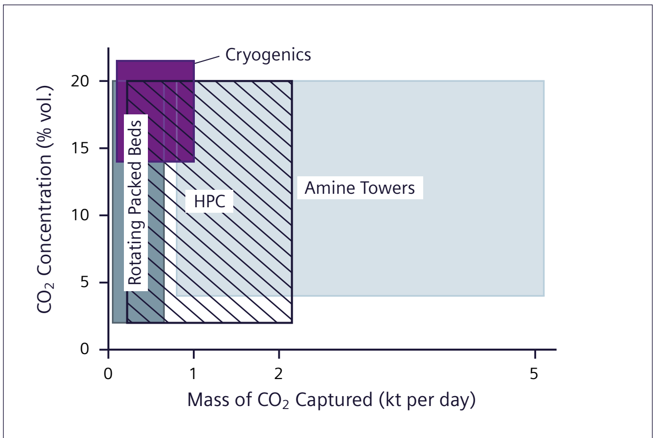

Figure 13: Second generation PCC technologies

Novel technologies

Two technologies that are the subject of active research are cryogenics and electro-chemical adsorption. These technologies may be expected to provide lower cost CO_2 capture, with less impact on plant performance.

Cryogenics involves cooling the flue gases and separating out CO_2 as a solid. A heat exchanger and heat recovery from compression is then used to melt the CO_2 so it can be transported as a pure liquid. Current cryogenic technologies require a minimum of around 15% vol. CO_2 in the flue gas stream (see Figure 13) and are not immediately applicable to gas turbines.

Electro-chemical adsorption involves passing CO_2-rich flue gas across a stack of electrodes. Activating the electrodes attracts the CO_2 and binds it to the surface, whereas deactivating the electrodes releases the CO_2. This concept can be used on gas streams with low CO_2 concentrations and is expected to be suitable for both gas turbines and DAC once the technology has been suitably scaled and demonstrated.

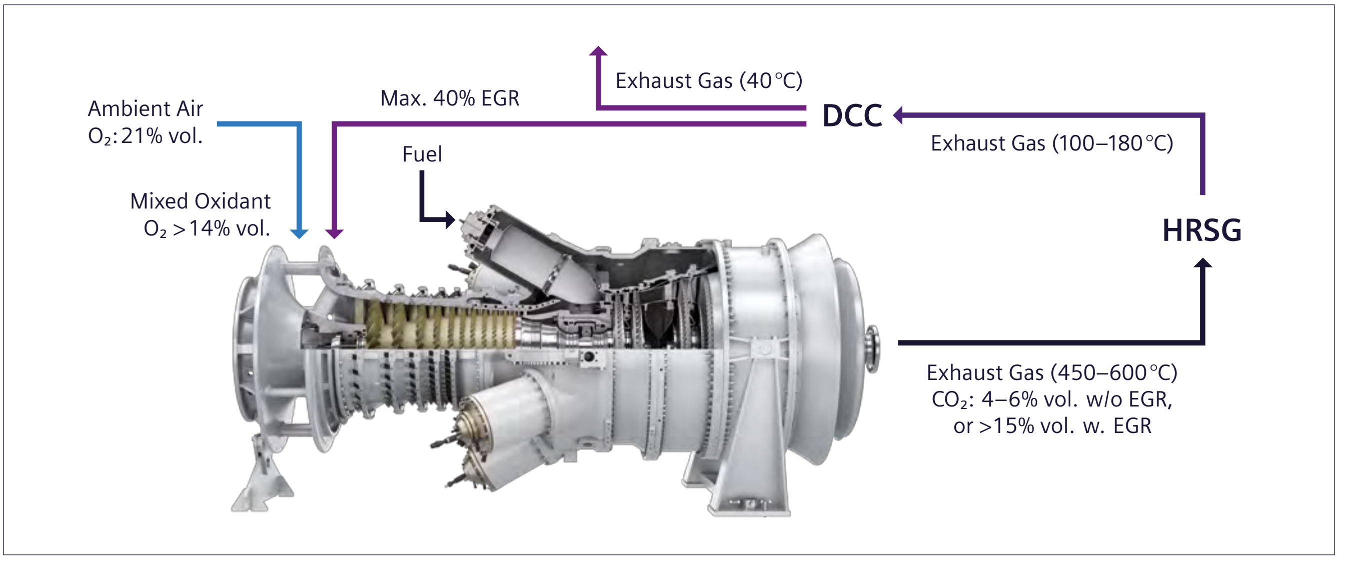

Figure 14: Simplified schematic diagram of Exhaust Gas Recirculation (EGR)

Exhaust gas recirculation

As mentioned above, low CO_2 concentrations in the exhaust from gas turbines present a major challenge for PCC. Exhaust Gas Recirculation (EGR) at a relatively lower rate than for oxyfuel firing offers a potential way to increase the CO_2 content. EGR involves cooled exhaust gases being recirculated to the air intake of the gas turbine and replacing a portion of the normal combustion air (Figure 14). The amount of exhaust gas that can be recirculated is limited to around 30–50% of the total exhaust mass flow, depending on the gas turbine model – otherwise the oxygen concentration is insufficient for stable combustion. At this EGR rate the exhaust CO_2 content is approximately doubled compared to a non-EGR unit. Adding supplementary oxygen (as for oxyfuel firing) allows even higher rates of EGR. For example, EGR of 75–85% can be reached, corresponding to CO_2 concentrations >15% vol. This introduces opportunities for simpler, lower-cost industrial PCC solutions such as mole sieves, membranes, and cryogenic technologies.

4.3 Costs and incentives

CCUS adds significant CAPEX and OPEX compared to a standard natural gas fired power plant, negatively affecting the LCOE of the generated power. Typical PCC installations reduce total plant efficiencies by 7–9 percentage points. On the other hand, compared to a decarbonized fuel, a CCS-equipped gas turbine may use a cheaper and readily available fossil fuel. Carbon capture technologies are generally considered to have preferential economics at mid to base load operating profiles. At lower operational profiles hydrogen and other sustainable fuels are more economical solutions – unless there are site-specific constraints that would impact the project economics. For example, regions that have access to cheap natural gas and / or unfavorable conditions for RES may opt for CCUS instead of sustainable fuels. Retrofitting CCS to gas turbines is straightforward for PCC technologies that do not require significant changes to existing equipment, whereas much greater modifications are required e.g. for oxyfuel combustion. In both cases a power plant must have available space and also sufficient remaining operational lifetime to recoup the investment costs, especially as the reduced efficiency in many instances will lead to a shifted dispatching (merit order) towards lower capacity factors. Positive economics for carbon capture projects will in the nearer term require incentives in the form of a carbon tax and / or carbon trading scheme. Governments around the world are working to implement economic frameworks for decarbonization.

5 Comparison of different decarbonization alternatives

5.1 Finding the best decarbonization solution for each case

Once the decision for a gas turbine-based power plant in a specific location is made, the next question to answer is which decarbonization route would be the best for this location. The feasibility of the different methods of decarbonization and the selection of the most beneficial option is not just depending on the available technologies, but will always depend on the specific project and local conditions, such as:

- Availability, quality (color, carbon content), and cost of low-carbon fuels – including sustainable hydrogen, natural gas for blue / turquoise hydrogen production, and other sustainable fuels – together with connection to existing or planned fuel supply infrastructure (pipeline with centralized storage for gaseous fuels, or local delivery for liquid fuels)
- Potential on-site storage capacity requirements.
- Connection potential to existing or planned CO_2 pipelines linked to geologically suitable storage sites and costs for CO_2 disposal.
- Available usable land area at the plant site.
- Size of the power plant and its annual operating hours, determined mainly by the electricity demand curve, the existing RES fleet in the region, electricity storage capacity in the grid, interconnection capabilities, and DSM regulations.
- Availability, cost, and generation patterns of local / regional RES (wind, solar, etc.) and their impact on the residual load profile (and thus the capacity factor of the power plant).
- Legislative requirements and available incentives for partial or full decarbonization.

These decision criteria will need to be analyzed for any new power plant to be built, as well as for any existing power plant where a retrofit towards decarbonization is to be made. In general, expected capacity factors and availability / prices of fuels will likely be the most important decision factors. As these are usually region specific, different world regions will show their own typical decarbonization strategy, which may deviate for some sites as other factors may influence or exert site specific decisions.

This chapter depicts the key aspects of making robust decisions, explains key decision criteria of the different decarbonization options and shows examples of techno-economic analyses for different decarbonization pathways. They are presented in a rather generic way, while for specific plants a detailed analysis is always required as long as there is no single obvious decarbonization pathway.

5.2 Investment decision criteria

The techno-economic analyses in this chapter are based on Levelized Cost of Electricity (LCOE), which is a macro-economic Key Performance Indicator (KPI) corresponding to the average net present cost of electricity generation for a power plant over its lifetime, including initial capital investments (CAPEX), maintenance costs and variable costs like fuel. As such, it is used to compare different methods of electricity generation on a consistent basis and can be used to determine which technology is most cost-effective for covering the electricity demand in a region.

While the Levelized Cost of Electricity (LCOE) is frequently used to compare different generation technologies and assess their impact on overall system cost, it is not the primary determinant in investment decisions made by generation companies. Utilities and Independent Power Producers (IPPs) primarily rely on traditional investment evaluation methods such as Net Present Value (NPV), Internal Rate of Return (IRR), break-even point, and payback period alongside consideration of investment risks and regulatory factors. In regulated markets and for state-owned utilities, policy frameworks and political priorities often play an equally decisive role.

Furthermore, LCOE do not directly reflect the profitability of a power plant: By contrast, marginal generation cost – which includes only variable fuel and maintenance costs – is the key metric for dispatch optimization and determines the plant's capacity factor during operation. Since dispatch revenues (whose margins are driven by the spread between offered marginal prices and market-clearing prices) constitute a significant portion of income for the power plant (alongside potential capacity and ancillary grid services remuneration), investors give priority to profitability-related KPIs over LCOE.

LCOE also fails to reflect all investment criteria from a macroeconomic perspective: It typically excludes grid integration and system operation costs, dispatchability constraints, time-of-operation effects, and external cost elements such as fuel storage outside plant boundaries or backup generation requirements.

In competitive electricity markets dominated by private participants, technology deployment decisions are guided by profit maximization rather than system-wide LCOE minimization. Therefore, while LCOE can be a useful comparative metric for technology benchmarking, actual investment choices depend on a broader set of factors: economic KPIs, market conditions, risk management considerations, regulatory environments, and subsidy schemes, all of which vary significantly across regions, individual projects, and over time. It is entirely possible for a project with a higher LCOE to represent a more attractive investment opportunity than one with a lower LCOE, depending on these prevailing conditions.

5.3 Carbon neutral fuel economics

Decarbonizing gas turbine power plants involves exploring various fuel options, as illustrated in Figure 3 (p. 8). This section provides an overview of the economics of producing these fuels, which represent the majority of the variable marginal costs associated with operating a power plant. Except for very low capacity factors, fuel costs constitute the majority of the Levelized Cost of Electricity (LCOE) of a power plant.

Predicting future fuel prices is challenging due to the complex interplay of production costs, storage, transportation, supply and demand markets, government incentives, R&D developments, and technological breakthroughs. Understanding the key levers driving production costs is a crucial first step.

Factors influencing fuel costs

There are two primary categories of sustainable fuels to consider: biofuels and renewable fuels of non-biological origin (RFNBOs) which include e-fuels like hydrogen and its derivatives. Some overlap exists, as methanol can be produced from electrolytic (green) hydrogen with bio-derived CO_2 added, or both hydrogen and CO_2 can be bio-sourced via biomass gasification through syngas.

Hydrogen production economics is straightforward: Green hydrogen from electrolysis involves CAPEX for the electrolyzer facility and its connection to renewable energy sources, and OPEX for green electricity, influenced by the capacity factor of renewable electricity and local market dynamics. Hydrogen must be transported and stored before consumption. Different regions may have varying storage and transport options, such as Europe's planned hydrogen pipeline network connected to cavern storage facilities, the European Hydrogen Backbone Network [28]. Infrastructure costs, likely in the billions of euros, must be amortized over large hydrogen quantities to ensure acceptable costs per kilogram for customers and offtakers. Supply and demand for green hydrogen must be driven through robust market mechanisms and include industries beyond power generation, such as methanol and ammonia feedstock, fertilizers, and iron / steel production.

Blue hydrogen can be produced via steam-methane reforming (SMR) or auto-thermal reforming (ATR) with carbon capture. This involves CAPEX for reforming and carbon-capture facilities, and OPEX for the natural gas feedstock.

Producing other e-fuels from hydrogen increases production costs: Synthesizing ammonia requires additional CAPEX for the synthesis plant and air separation unit, and additional OPEX to account for the synthesis efficiency. E-methanol production similarly requires additional CAPEX for synthesis equipment and additional OPEX for the DAC carbon feedstock.

Similarly, biogenic fuel production costs combine CAPEX for synthesis equipment and OPEX for input waste biomass products and handling.

Future Fuel price predictions

Table 2 summarizes market price and production cost ranges for various fuels, in typical market units and normalized on an energy basis ($\$/MWh_{th}$) to facilitate cost and LCOE comparisons when converted to electricity.

Fuel	Market Price	Energy-basis price $/MWh$_{th}$
Natural Gas (US Henry Hub)	$1.50–$6/MMBtu	$5–$20
Natural Gas (Dutch TTF)		$30–$60
Diesel (New York)	$2–$3.50/gallon	$50–$90
Hydrogen (blue, Europe)	€1.7–€3.4/kg	$60–$120
Hydrogen (green, Europe)	€3.4–€6/kg	$120–$210
Ammonia (fossil, Europe)	€380–€600/ton	$85–$130
Ammonia (blue, Europe)	€430–€640/ton	$100–$145
HVO (Hydrotreated vegetable oil)	$1500–$2500/ton	$120–$205
Methanol (fossil, Rotterdam)	€200–€400/ton	$40–$85
Fuel	**Production Costs**	**Energy-basis cost $/MWh$_{th}$**
Bio-Methanol (expected mature production costs)	$230–$880/ton	$40–$160
e-Methanol from DAC (current production costs)	$1100–$2400/ton	$200–$440
e-Methanol from DAC (expected mature production costs)	$290–$630/ton	$50–$115

Table 2: Price and production cost ranges for a variety of fossil and decarbonized fuels. Ranges are indicative of the lowest and highest prices over 2024 and 2025. As they are not traded commodities, bio- and e-methanol show expected ranges of production costs – market prices will be higher. Sources: Natural Gas (Henry Hub), Diesel (New York): EIA; Ammonia, Natural gas (Dutch TTF): Siemens Energy internal data; Hydrogen: Hydrogen Council; Methanol (fossil): shipandbunker.com; Methanol: IRENA ([27]); HVO: Neste/Argus Media. Assumed exchange rate USD-EUR: 1.17

Figure 15 illustrates expected production costs for green and blue hydrogen, alongside expected natural gas prices (including CO_2 prices). Green hydrogen cost expectations were increased in 2024 for higher-than-expected inflation and raw material cost increases.

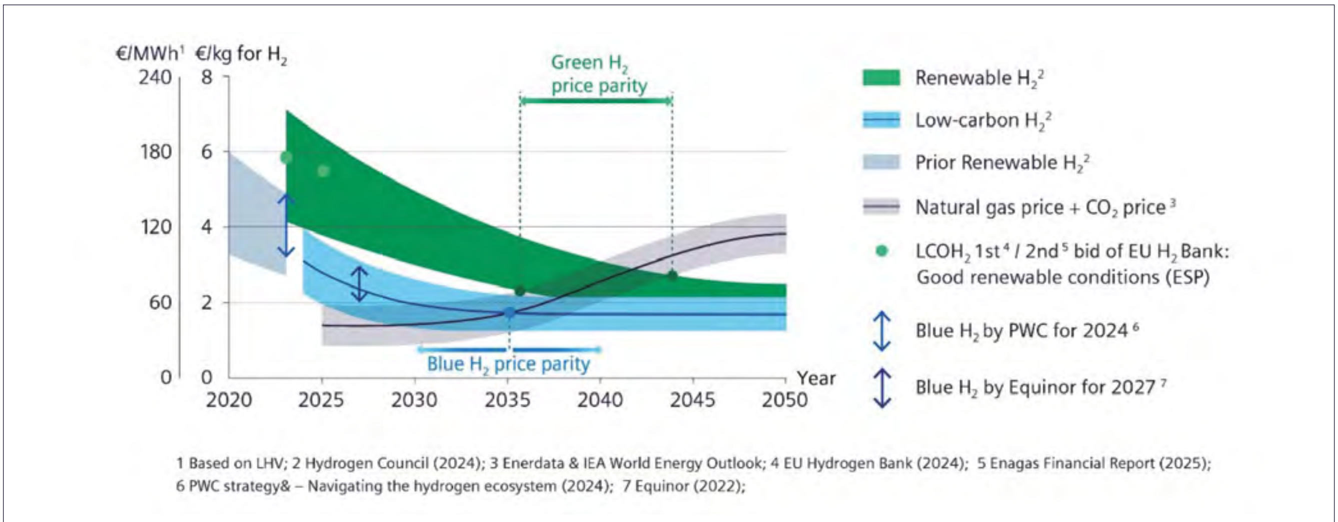

Figure 15: H_2 Price

Green hydrogen's large price range today is expected to decrease significantly over time due to several factors: The LCOE of renewable electricity from solar and wind is expected to continue decreasing along the experience curve, as has been steadily happening over the last two decades. As production and experience in green hydrogen facilities grow, along with modularization and increased R&D, hydrogen production costs should also decrease along their own learning curve. Transportation and storage facilities required to manage and deliver hydrogen quantities needed to decarbonize economies will be expensive for society, but as hydrogen production increases, costs will spread over more quantities, reducing per-unit added costs. Green hydrogen production costs can be lower in areas with optimal renewable energy conditions, such as Patagonia, NW South Africa / Namibia, or Australia, but additional transport and processing costs (using ammonia as a transport vector) must be added to the hydrogen price at the destination. Despite these additional costs, final price at destination may still be cheaper than locally produced green hydrogen, creating a market for large-scale green hydrogen production at the optimal production locations throughout the world.

For Europe, and depending on the speed of blue and green hydrogen cost decreases and CO_2 cost increases, price parity is expected around the mid-2030s for blue hydrogen and between 2035 and 2045 for green hydrogen compared with conventional natural gas (including carbon pricing).

Blue hydrogen is expected to achieve price parity with European natural gas earlier than green hydrogen. Comparing the low end of blue hydrogen's price range with the high end of fossil natural gas's price range today may be misleading, as the gas source for blue hydrogen is often the same as the natural gas source. Blue hydrogen costs are expected to decrease, and fossil natural gas prices increase, particularly when factoring in carbon pricing.

For blue ammonia in Europe, the price premium compared to fossil ammonia can be as low as around $50 / ton. Costs for both blue and green ammonia are expected to decrease over time for the same reasons discussed for green hydrogen.

While e-methanol production costs today are significantly higher than fossil methanol prices, they are expected to reduce significantly over time as green hydrogen and DAC carbon costs decrease for the same reasons discussed for green hydrogen. In the beginning, e-methanol production with other CO_2 sources like BECCS and unavoidable emissions may reduce costs and start the build-up of a larger methanol ecosystem.

For bio-methanol, the low-end of the production cost range is expected to be similar to fossil methanol, but uncertainty exists as many industries intend to use these biofuels to meet their decarbonisation targets, and bio-waste feedstocks may thus increase in cost and decrease in quality. In addition, the overall availability of biomass for energy purposes, especially 2nd generation fuels, will always remain limited.

All of these expected cost reductions depend strongly on industry scaling-up, driven by cost reductions down a learning curve and economies of scale. However, it is to be noted that the expected speed of deployment of these new technologies can change.

Finding the best technology for a specific project

In conclusion, specific recommendations for decarbonised fuels depend strongly on local availability and market conditions. Over time, sustainable fuels should become competitive with fossil alternatives, but this depends on policy regulations, investments and continued learning by doing. For a real project, a case specific analysis of all economic, infrastructure, logistics and availability factors is required before making any decision on the best route towards decarbonization. In the following sections we describe in more detail two specific use-case comparisons.

5.4 Economic comparison of CCS vs. Hydrogen Power Plants

This section discusses a comparison of options for a new-build "large" combined-cycle power plant (~>100 MW). Plants of this size must be necessarily connected to a pipeline (today this would be the natural gas pipeline system). Two main technology options appear possible to field such a plant in a decarbonized way: Hydrogen operation or natural gas operation with CCS. For this comparison, we assume there is a hydrogen pipeline network nearby and that the plant could also have access to a carbon hub with a CO_2 pipeline connected to a robust CO_2 storage facility with sufficient size. An analysis of LCOE is done to compare both technologies.

When comparing both decarbonized technologies, the following assumptions are made:

- For CCS, the total plant CAPEX cost with CCS could be as much as 2–3 times the cost of a power plant without CCS. Power output and efficiency of the CCS plant will be reduced, with the efficiency being reduced by ~7–9 percentage points relative to the natural gas engine without CCS, depending on technology and power plant size. OPEX costs for the plant with CCS would increase, to account for the extra maintenance, regular replacement of solvents, and CO_2 transportation and storage costs, which are included in the OPEX

- For the Hydrogen plant, CAPEX cost would be around 5–10% higher than the cost of a natural gas plant, depending on technology and site-specific aspects. While these plants are still in active R&D development today, and an introductory performance may apply for the first units, we expect that in the future the hydrogen plant would run at nearly the same baseload power and efficiency as a natural gas model, which is the development goal of the technology. From an OPEX perspective, the main costs here will be for the hydrogen fuel, including any transport costs for pipeline delivery to the site.

The comparison is typical for two power plants in which one has high CAPEX / low OPEX, while the other has low CAPEX / high OPEX characteristics. Both plants will show different LCOE over the capacity factor, as a low CAPEX / high OPEX plant will be more competitive at low number of operating hours per year, while the high CAPEX / low OPEX will show an advantage at high-capacity factors. A very interesting question is to determine the break-even point of both technologies.

Figure 16 shows the LCOE versus the hours of operation per year for both technologies. For the CCUS plant, the natural gas price is taken at the midpoint of the range in Table 1 (\$45 / MWh_{th}) and data is plotted for two cases: 2 × CAPEX with a 7 percentage points reduction in efficiency, and 3xCAPEX with a 9 percentage points reduction in efficiency. For the hydrogen plant, data is plotted at the midpoints of the price ranges for blue (\$3 / kg–\$90 / MWh_{th}) and green hydrogen (\$5.50 / kg–\$165 / MWh_{th}). At the highest capacity factor, the LCOE for CCUS is between \$140–\$160 / MWh_{th}, and the LCOE for hydrogen is between \$170–\$300 / MWh_e. The crossing points of H_2 at \$5.50 / kg with CCUS is between 900–1800 hours per year, while for H_2 at \$3 / kg, it is between 3500–7000 hours per year. Simply put, for more sustained baseload operation, the LCOE for CCUS is, generally speaking, better. For lower hours of operation per year, for mid-merit and backup power, the LCOE for the hydrogen plant would be better. As discussed in section 4, CCUS is also technically more suited to continuous operation and is less appropriate for cyclic operation. A project specific view will also need to factor in potential H_2 price reduction over the lifetime of the plant, as the graph will change from year to year. An investment cash flow analysis will be able to factor in these price evolutions over time.

5.5 Economic comparison of gas turbines operating on carbon-neutral liquid fuels

The second case study analyses a power plant without access to any natural gas or hydrogen pipelines, such as used for backup power or in island grids. Often built as simple cycle units, these plants are today typically running on diesel fuel for <1000 hours per year. In this case the comparison will be between different decarbonized liquid fuels: ammonia, methanol and HVO.

To calculate the final LCOE, it is important to consider changes required to the power plant that would increase CAPEX, such as storage, cracking and emissions treatment. Additionally, the OPEX will mainly depend on the differences in fuel prices.

For emissions after-treatment, this will depend on local emissions regulations associated with these types of power plants. As discussed in the ammonia section, ammonia could be burned directly or cracked into hydrogen and nitrogen. HVO can be burned directly with minimal or no modifications required, as this is effectively a diesel

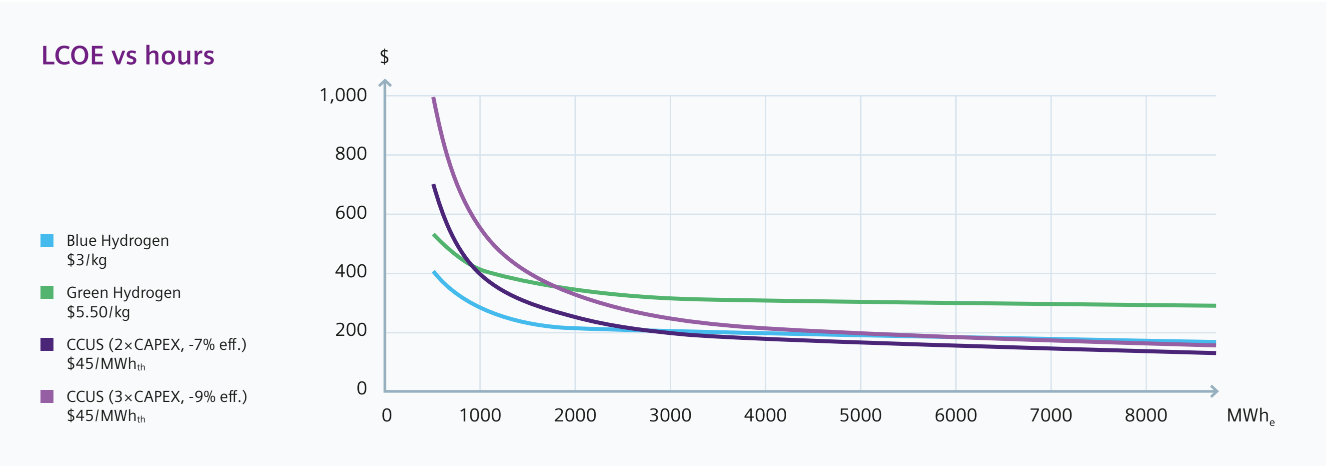

Figure 16: LCOE comparison of CCUS versus hydrogen for a large combined-cycle power plant. LCOE plotted versus hours of operation per year.

exchange drop-in fuel. Methanol will require some modifications to the combustion system, as the lower heating value is roughly half of HVO.

Consider a 15 MW simple cycle gas turbine power plant operating as a peaker with 40% efficiency. To estimate the costs of additional storage infrastructure, consider a case where the operator is required to store sufficient fuel to run for 100 hours, a total of 3750 MWh_{th} of energy. For fuel storage, HVO and methanol can be stored in the same tanks used for diesel fuel storage, although methanol will require additional nitrogen blanketing and double the storage volume compared to HVO. Ammonia will require dedicated ammonia storage tanks at approximately 10 bar / 25°C or at -33°C, with the cryogenic storage being the standard solution in industry. HVO storage cost is assumed to be half the cost of methanol as it has twice the LHV and does not need blanketing. The very high costs for liquid hydrogen and the continuous boil-off (up to 0.3% per day) make it unfeasible for this type of peaking application, thus the focus on liquid fuels.

Fuel	Storage cost per MWh_{th}	Total storage cost
Liquid hydrogen	$2700	$10 M
Ammonia	$$385	$1.4 M
Methanol	$161	$600 k
HVO / Diesel	$80	$300 k

Table 3: Storage costs for various fuels. (source: IEA [29])

For ammonia, as described in more detail above, the lowest cost option would be to burn it directly, but the technology is not ready yet and it would likely require significant additional after-treatment for NO_x, N_2O, and NH_3 emissions through the stack. The other option is to crack the ammonia into a mixture of hydrogen and nitrogen that would then be burned in the turbine. The costs of ammonia crackers are still quite uncertain but could be on the order of the cost of the powerplant, thus doubling the total CAPEX and significantly increasing the LCOE for this application. Depending on the level of integration between the powerplant and the ammonia cracker, the efficiency difference with conventional fuels will also vary.

Figure 17 shows a comparison of LCOE plotted versus hours of operation for cracked blue ammonia and HVO. Fuel prices are taken as the mean of the ranges shown in Table 2 above. With these assumptions, the cross-over point is around 1800 hours of operation per year. Thus, similarly to the H_2 vs. CCS comparison in Section 5.4, for low number of operating hours the lower CAPEX option is preferred, even if the fuel cost is higher.

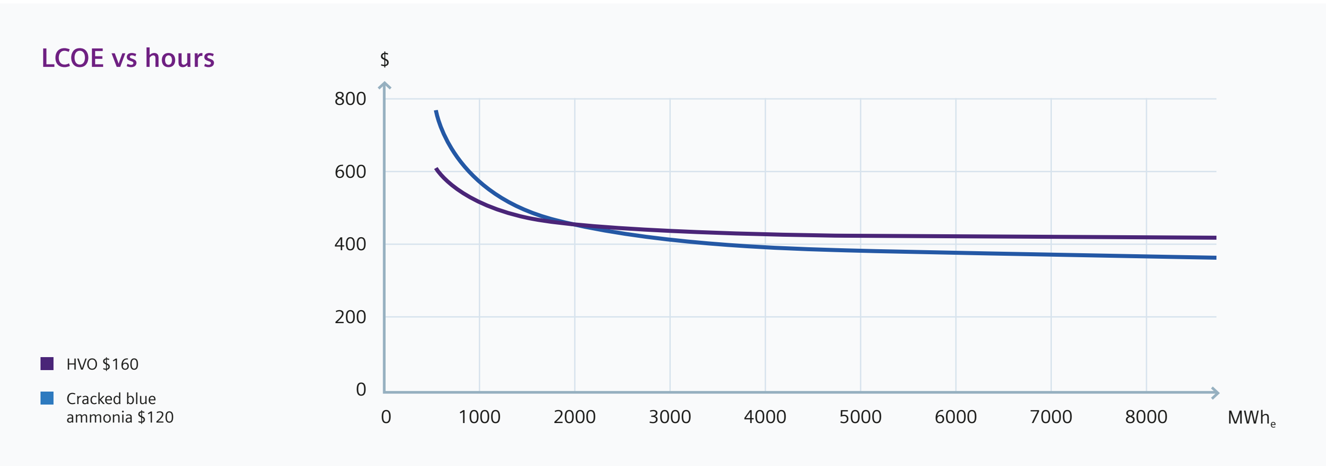

Figure 17: LCOE versus hours comparison for cracked blue ammonia and HVO.

6 Outlook

Gas turbines and combined cycle power plants are the most economical way of providing residual load and much-needed grid ancillary services in a decarbonized energy system. Key advantages include low investment costs and the ability to generate fully dispatchable power for sustained periods of time when meteorological conditions are unfavorable for wind and solar. In particular, gas turbines offer very high operational flexibility to compensate for short term intermittency. For combined heat and power applications they can also provide decarbonized heat, e.g. for process industries and district heating networks.

Decarbonization of gas turbines is expected to take different forms in different regions. In most economies gas turbines fired by green hydrogen represent a promising solution for renewable Power-to-X-to-power, but in some cases ammonia or another sustainable fuel, or carbon capture will be a better option. Currently, there is no clear 'winner' based on techno-economics since several factors are strongly location dependent while others like fuel prices, infrastructure for transport and storage of fuels and CO_2, regulatory incentives are yet to be fully developed. This variety of possible technical solutions is exciting, but it also demands action in the form of R&D programs that should follow different development paths simultaneously. There is little prospect of a combustion system that is optimized for (say) 100% H_2 also being capable of firing pure NH_3, which has very different fuel properties. Furthermore, the success of decarbonization depends on the full supply chain including, e.g. fuel processing and distribution infrastructure, exhaust aftertreatment and other technologies. Continuing partnerships between gas turbine OEMs, academia, industry, and governments are essential to advance the technology for decarbonization and roll it out quickly to practical applications.

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