Fraunhofer ISI

Analyse der Umrüstbarkeit von fossilen Gaskraftwerken auf Wasserstoff

Projektbericht

Fraunhofer-Institut für System- und Innovationsforschung ISI

Ort: Karlsruhe
Datum: 11.10.2024
Status: Endbericht

Leistungserbringer

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Leistungszeitraum

Projektlaufzeit:	17.06.2024 - 31.08.2024
Geplanter Projektstart:	01.06.2024
Gesamtlaufzeit:	2 ½ Monate

Auftraggeberin

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Content

1 Executive Summary

Hydrogen power plants are meant to serve as a backup for renewable energy sources in the future energy system. These power plants are similar in many ways to their fossil counterparts that use natural gas as fuel. However, hydrogen differs in numerous important properties from natural gas or methane, which is why operators of such power plants need to take into account some changes early during the planning phase of retrofit or new construction. This includes infrastructural aspects such as adapting fire and explosion protection and considering the changed space requirements of certain components for future operation with hydrogen. Of major importance is securing connection to the planned future hydrogen grid.

Gas turbines, and thus the key component of gas-fired power plants, which are suitable for the permanent operation of these power plants with pure hydrogen, are not yet commercially available. Currently available gas turbines would only allow the addition of hydrogen up to a certain point with a limited decarbonization effect. Gas turbine manufacturers face the challenge of ensuring safe, stable, and efficient combustion of pure hydrogen. The properties of hydrogen exacerbate common and already known issues such as high nitrogen oxide emissions and undesirable combustion dynamics. As there are no fundamentally new challenges ahead, gas turbine manufacturers can draw on years of development experience and further develop existing concepts. Aside further developing combustion technology, this might also include new corrosive-resistant materials to be tested and the adaptation of the turbine cooling system. The goal of finishing these developments and achieving market maturity by 2030 currently appears realistic, as the main challenges are being addressed by manufacturers in ongoing research projects. Small-sized hydrogen turbines have already been demonstrated in a relevant environment. These concepts still need to be finalized and scaled up to heavy-duty gas turbines. However, the limited availability of hydrogen could delay the development and market readiness of hydrogen-capable gas turbines and the introduction of hydrogen power plants. When hydrogen turbines are commercially available, the limited gas turbine production capacity must be (partially) dedicated to these new hydrogen turbines to ensure the timely retrofitting of fossil fuel-fired power plants and the expansion of newly built hydrogen plants.

The power plant strategy can help to create a roadmap for hydrogen projects. It should consider different types of gas-fired power plants (open cycle or combined cycle gas turbine), which are suitable for different purposes; an early switch to hydrogen as a fuel (low number of full load hours due to limited hydrogen supply) on one hand and the replacement of coal-fired power plants (high number of full load hours) on the other hand. Currently planned hydrogen-capable gas-fired power plants focus on efficiency and rely on combined cycle plants, while neglecting the less efficient but cheaper open cycle plants that could be better suited as early hydrogen power plants. In general, the details of the power plant strategy and the associated capacity mechanism should be quickly developed to create clear framework conditions and provide planning security for power plant operators.

2 Zusammenfassung

Wasserstoffkraftwerke sollen im zukünftigen Energiesystem als Reserve für erneuerbare Energiequellen dienen. Diese Kraftwerke sind in vielerlei Hinsicht ihren fossilen Pendants ähnlich, die Erdgas als Brennstoff verwenden. Wasserstoff unterscheidet sich jedoch in zahlreichen wichtigen Eigenschaften von Erdgas oder Methan, weshalb Betreiber solcher Kraftwerke bereits in der Planungsphase von Nachrüstungen oder Neubauten einige Änderungen berücksichtigen müssen. Dazu gehören infrastrukturelle Aspekte wie die Anpassung des Brand- und Explosionsschutzes sowie die Berücksichtigung der veränderten Platzanforderungen bestimmter Komponenten für den zukünftigen Betrieb mit Wasserstoff. Von großer Bedeutung ist die Sicherstellung des Anschlusses an das geplante zukünftige Wasserstoffnetz.

Gasturbinen, und damit die Schlüsselkomponente von Gaskraftwerken, die sich für den dauerhaften Betrieb dieser Kraftwerke mit reinem Wasserstoff eignen, sind noch nicht kommerziell verfügbar. Derzeit verfügbare Gasturbinen würden nur die Beimischung von Wasserstoff bis zu einem bestimmten Wert mit begrenztem Dekarbonisierungseffekt zulassen. Hersteller von Gasturbinen stehen vor der Herausforderung, eine sichere, stabile und effiziente Verbrennung von reinem Wasserstoff zu gewährleisten. Die Eigenschaften von Wasserstoff verschärfen bekannte Probleme wie hohe Stickoxid-Emissionen und unerwünschte Verbrennungsdynamiken. Da keine grundsätzlich neuen Herausforderungen bevorstehen, können Hersteller von Gasturbinen auf jahrelange Entwicklungserfahrung zurückgreifen und bestehende Konzepte weiterentwickeln. Neben der Weiterentwicklung der Verbrennungstechnologie könnte dies auch die Erprobung neuer korrosionsbeständiger Materialien und die Anpassung des Turbinenkühlsystems umfassen. Das Ziel, diese Entwicklungen bis 2030 abzuschließen und Marktreife zu erreichen, erscheint derzeit realistisch, da die Hauptprobleme von den Herstellern in laufenden Forschungsprojekten angegangen werden. Kleinere Wasserstoffturbinen wurden bereits in einem relevanten Umfeld demonstriert. Diese Konzepte müssen noch finalisiert und auf Schwerlastgasturbinen hochskaliert werden. Die begrenzte Verfügbarkeit von Wasserstoff könnte jedoch die Entwicklung und Marktreife von wasserstofffähigen Gasturbinen sowie die Einführung von Wasserstoffkraftwerken verzögern. Wenn Wasserstoffturbinen kommerziell verfügbar sind, muss die begrenzte Produktionskapazität von Gasturbinen (teilweise) diesen neuen Wasserstoffturbinen gewidmet werden, um die rechtzeitige Umrüstung von fossil befeuerten Kraftwerken und den Ausbau neugebauter Wasserstoffkraftwerke sicherzustellen.

Die Kraftwerksstrategie kann helfen, einen Fahrplan für Wasserstoffkraftwerksprojekte zu erstellen. Sie sollte verschiedene Arten von Gaskraftwerken (reine Gasturbinenkraftwerke oder Gas-und-Dampf-Kombikraftwerke) berücksichtigen, die für unterschiedliche Zwecke geeignet sind; ein frühzeitiger Wechsel zu Wasserstoff als Brennstoff (geringe Zahl an Volllaststunden aufgrund begrenzter Wasserstoffversorgung) einerseits und der Ersatz von Kohlekraftwerken (hohe Zahl an Volllaststunden) andererseits. Derzeit geplante wasserstofffähige Gaskraftwerke konzentrieren sich auf Effizienz und setzen auf Gas-und-Dampf-Kraftwerke, während die weniger effizienten, aber günstigeren reinen Gasturbinenkraftwerke, die besser als frühe Wasserstoffkraftwerke geeignet sein könnten, vernachlässigt werden. Im Allgemeinen sollten die Details der Kraftwerksstrategie und des zugehörigen Kapazitätsmechanismus zügig entwickelt werden, um klare Rahmenbedingungen zu schaffen und Planungssicherheit für Kraftwerksbetreiber zu gewährleisten.

3 Introduction

3.1 Background

Gas-fired power plants, which are initially to be operated with fossil natural gas and later with hydrogen and are therefore planned as "H2-Ready" (H2R), are planned as key elements of the German power plant strategy ("Kraftwerksstrategie"). This technology promises low-emission electricity and heat production in hydrogen operation and should help to reduce dependence on fossil fuels. In general, they provide controllable capacity and thus flexibility to the future energy system, which will be dominated by fluctuating renewable energy sources such as solar and wind. This makes them especially important in times when renewable energy sources are not sufficient to meet demand and other flexibility options have already been exhausted. The specific use cases and the number of full load hours differ however between different types of hydrogen power plants. There are still considerable uncertainties regarding the timely and economic feasibility of converting gas-fired power plants to 100% hydrogen operation.

In Germany, the plan is to initially operate most of these hydrogen-capable gas-fired power plants with fossil natural gas and to switch to hydrogen presumably between 2035 and 2040 in accordance with the key points of the power plant strategy. The Kraftwerksstrategie provides for temporary funding for the construction and operation of gas-fired power plants. This funding is divided in a decarbonization measure and a measure for security of supply. While the former includes in total 7.5 GW of hydrogen and hydrogen-capable gas-fired power plants, the latter includes additionally 5 GW of gas-fired power plants without the obligation to switch to hydrogen as a fuel. The decarbonization measure includes 5 GW of new H2-ready power plants and 2 GW of modernizations and retrofits of existing natural gas power plants to H2-readiness, which are to be converted to hydrogen operation from the 8th year of operation at the latest. From the switch to hydrogen, the differential costs between hydrogen and natural gas are subsidized for up to 800 full load hours (FLH) per year. In addition, 500 MW of new power plants are to be operated directly with hydrogen ("H2-Sprinter"). A minimum of 200 FLH are required to receive funding [1]. The first tenders for funding are planned for early 2025. In total, controllable power plant capacities in the amount of 12.5 GW are therefore subsidized by the Kraftwerksstrategie with details of the tender still to be finalized. In addition, the introduction of a capacity mechanism is planned to ensure sufficient flexible power plant capacities in the long term. The specific design of the capacity mechanism is currently being developed by the German government and should be operational in 2028 [2].

The German government is currently examining options for extending the combined heat and power (CHP) Act, which is set to expire in 2026. This extension may include additional incentives for hydrogen power plants through specific tendering segments for CHP systems. This amendment to the CHP Act is widely expected, but there are no details or timetable yet. It remains to be clarified to what extent CHP plants used primarily for heat generation can contribute flexibly to stabilizing the electricity system.

3.2 Project Plan

This report provides a detailed list of the relevant technology and components required for the retrofit of power plant operation from fossil natural gas to hydrogen. The current gas turbine product portfolio of companies such as Siemens Energy, Mitsubishi and General Electric is analyzed and technical challenges that still need to be overcome by the companies are identified. The extent to which the turbine manufacturers' current and planned research and development projects can meet these technical challenges within the timeframe set by the German power plant strategy is being examined. An assessment of the technology readiness level (TRL) and the market maturity of hydrogen power plants is made. In addition, the production capacity of gas turbine manufacturers are evaluated with regard to the German power plant strategy and the expansion path of hydrogen power plants in Germany and Europe in the current long-term scenarios of the Federal Ministry for Economic Affairs and Climate Action (BMWK). These are the two orientation scenarios O45-Strom and O45-H2, which reduce the solution space covered in previous scenarios, but retain the orientation of their predecessors with a focus on electrification (O45-Strom) and a more widespread use of hydrogen (O45-H2). For more information like detailed dashboards and presentation slides it is referred to the website of the long-term scenarios [3].

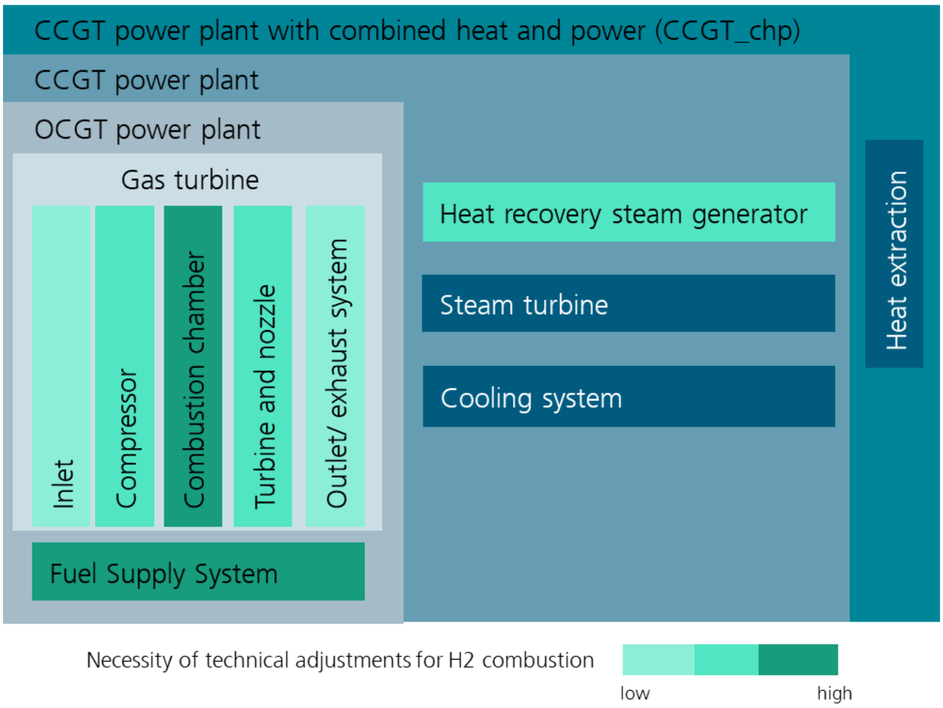
The various H2R power plant projects planned in Germany and their locations and operators are listed. Of these projects, three potential locations are selected representing three different types of hydrogen power plants, (i) open cycle gas turbine (OCGT), (ii) combined cycle gas turbine (CCGT) and (iii) combined cycle gas turbine with combined heat and power (CCGT_CHP). These case studies are evaluated to determine the conditions under which economical operation is possible. To this end, these case studies are placed in the model world of the long-term scenarios and evaluated on the basis of model-endogenous market values for hydrogen, heat and electricity. In addition, the extent to which the planned type of power plant can be beneficial for the energy system and the electricity grid and how likely the switch from fossil gas to hydrogen is within the specified time frame is investigated.

4 General Technical Fundamentals

4.1 Relevant Technology and Components for Retrofitting

Figure 1 shows main components of gas turbine power plants in simplified form and has been revised from Ref. [4]. Open cycle gas turbine (OCGT) power plants mainly consist of the fuel supply system, i.e. pipework and fuel compressors to supply the gas turbine with natural gas or alternative fuels like hydrogen, and the gas turbine with its various parts. In a combined cycle gas turbine (CCGT) power plant a steam cycle is added consisting of a heat recovery steam generator, a steam turbine and a corresponding cooling system. With the exception of the heat recovery steam generator, the steam cycle is separate from the operation of the gas turbine and therefore independent of the choice of fuel for combustion in the gas turbine. This is shown by the color code in Figure 1, which indicates the need for technical adjustments for the retrofit from natural gas to hydrogen combustion. In a CCGT power plant with combined heat and power (CCGT_CHP), heat is extracted from the steam cycle to supply e.g. the district heating grid. Power or CHP plants with gas engines instead of gas turbines are also possible. These are generally smaller in size and are used as emergency power generators and have only accounted for a small share of newly installed capacity in Germany over the last 20 years [4]. Therefore, the focus in this study is on turbine-based gas-fired power plants. In the following, detailed requirements and challenges for the fuel switch from natural gas to hydrogen are presented for the power plant components shown.

Figure 1 **Main components of gas turbine power plants**



Source: Revised from Ref. [4].

4.2 Challenges of Retrofitting from Fossil Gas to Hydrogen

Today's gas turbine power plants were developed and built for natural gas or methane combustion. Different properties of hydrogen compared to methane are the reason for the need for action to make gas turbine power plants fit for hydrogen combustion ("H2-ready"). Key properties for combustion are given in Figure 2.

Figure 2 Key properties for the combustion of methane and hydrogen

Parameter	Unit	Hydrogen	Methane
Molecular weight	g/mol	2.016	16.040
Density at NTP	kg/m³	0.08	0.65
Self-ignition temperature[a]	K	845 - 858	813 - 905
Minimum ignition energy	mJ	0.02	0.29
Flammability range in air	vol%	4 - 75	5 - 15
Adiabatic flame temperature (at constant equivalence ratio and pressure)	K	2318 - 2400	2158 - 2226
Laminar flame speed (max)	cm/s	325	45
Lower heating value (vol.)	MJ/Sm³	10.8	35.8
Higher heating value (vol.)	MJ/Sm³	12.8	39.7
Wobbe index (LHV basis)	MJ/Sm³	40.7	47.9

Source: Taken from Ref. [5], based on Refs. [6, 7].

The difference in the volumetric lower heating value (shown in Figure 2) corresponds to a different energy density and leads to a fuel gas volume flow rate for hydrogen that is about 3.3 times higher than for natural gas at the same pressure [5, 8].

The so-called Wobbe index (see Figure 2 last line) is defined as the quotient of the lower heating value and the square root of the specific gravity of the fuel and air and serves as an indicator of the interchangeability of fuel gases. Compared to other hydrocarbon fuels such as propane (73.3 MJ/Sm^3 [7]), hydrogen and methane have similar values. This indicates that combustion systems designed for natural gas can be used with hydrogen without large scale modifications [5]. However, this index does not account for variations in combustion properties such as burning velocities [9]. And indeed, the significantly higher flame speed and also the higher flame temperature of hydrogen compared to methane are challenging [10]. These factors can result in locally higher temperatures, which can increase both the thermal stress on the turbine components and nitrogen oxide (NOx) emissions in the combustion chamber [11, 12]. Blending 50 vol% hydrogen into natural gas can increase NOx emissions by 35% according to preliminary laboratory data by General Electric (GE) [13]. However, actual NOx emissions vary based on multiple factors including fuel composition and combustion operating parameters.

The flame speed values given in Figure 2 are determined by the chemical composition of the selected fuel (i.e. hydrogen or natural gas). Here too, the relevant flame speed in the combustion chamber can vary, as it also depends on other factors such as the fuel-air ratio, temperature, pressure, turbulence and dilution during combustion. The flame speed during combustion must not exceed the flow velocity of the fuel-air mixture, otherwise, upstream flame propagation is possible.

This phenomenon is known as “flashback” and can lead to serious damage of the gas turbine components and safety issues [8, 14]. The risk of flashback is further increased by the shorter ignition delay time of hydrogen, i.e. a shorter period of time between the first exposure of a flammable mixture to an ignition source and the start of combustion [15]. By ensuring proper mixing, maintaining appropriate flow velocities, and optimizing the combustor design, the risk of flashbacks can be minimized. If a flashback still occurs, flashback detectors can trigger appropriate warnings or shut down the turbine, which may lead to downtime but can prevent damage and safety risks.

Another figure of merit derived from fluid properties is the Lewis number, which is defined as the ratio of thermal diffusivity to the mass diffusivity of a fuel and is an indicator of flame stability and the sensitivity of flames to disturbances. Values of 1, as with methane, or higher indicate stable combustion, while values below 1, as with hydrogen at around 0.45, suggest more unstable flames [5, 16]. Therefore, the risk of combustion dynamics, i.e. self-sustained combustion oscillations at or near the acoustic frequency of the combustion chamber are more likely with hydrogen combustion [17]. These oscillations can lead to unstable combustion, which can potentially cause damage to the gas turbine or reduce its efficiency and reliability.

A hydrogen flame has a lower emissivity compared to a methane flame due to the lower concentration of radiation types such as soot, CO2 and hydrocarbon radicals. Consequently, a hydrogen flame has a lower luminosity and requires ultraviolet flame detection, as opposed to infrared flame detection, which is commonly used in natural gas applications [5, 18].

In addition to the combustion properties, there is the phenomenon of hydrogen embrittlement, which describes the transition from ductile to brittle behavior of solid materials such as steel due to hydrogen diffusion through the solid lattice and the hydrogen interaction with crystal defects [19]. This can lead to cracks and shorten the lifespan of the components, impairing the structural integrity of the turbine components, which may result in potential failures. Addressing these issues requires careful material selection, protective coatings, and monitoring to ensure the safe operation of gas turbines running on hydrogen fuel.

In Table 1, detailed requirements and challenges for the fuel switch from natural gas to hydrogen are presented for every subsystem shown in Figure 1. Table 1 is based on Ref. [4] and has been revised. The "Challenge" column lists the tasks that are aimed at either power plant operators or gas turbine manufacturers.

Table 1 Requirements and challenges for H2 operation

Subsystem	Cause/Difference	Requirement	Challenge
Fuel gas supply system	Fuel switch	Fuel supply	Secure connection to hydrogen grid [4, 5]
	Fuel gas volume flow Energy density (lower heating value, LHV)	Larger nominal diameter of the pipework or higher pressure losses [5, 8, 20]	Consider (future) space requirements during planning
	Embrittlement of steels by hydrogen	Upgrade to H2-resistant fuel gas pipework and fuel compressors due to changed material stress [4, 5, 21]	

Subsystem	Cause/Difference	Requirement	Challenge
		Need to replace pipework and fuel compressors more likely for high pressure systems (> 10 barg) [5]	
	Mixed operation CH4 and H2	Space requirement for parallel construction of the H2 transfer station, depending on the pressure level [5]: < 10 barg: 20-50 m^2 > 10 barg: up to 900 m^2	Consider (future) space requirements during planning
	Mixed operation CH4 and H2	Space requirement for H2 and natural gas blending: 7 - 30 m^2 [5]	Consider (future) space requirements during planning
Combustion system and gas turbine (GT)	Several different properties of H2 during combustion (Wobbe index)	For > 50 vol% H2: Burner replacement with new combustion technology Possibly replacement of combustion chamber with adapted cooling concept [5, 20]	H2 combustion in GT still under development, TRL should be considered [5, 22]
	Lewis number Flame speed	Avoidance or reduction of dynamic and thermoacoustic instabilities, i.e. combustion chamber pulsation [8]	Gas turbine development for stable hydrogen combustion
	Flame speed Ignition delay time	Check protection against flashbacks [8, 10, 14]	Flashback protection development
	Emissivity	Replacement of flame monitor with different flame detection [5, 23]	
	Adiabatic flame temperature Flame speed	Comply with NOx emission guidelines, e.g. via: - NOx neutralization in a denitrification unit (SCR) in heat recovery system - Dry-low-emission (DLE) combustion technology - water injection in the combustion chamber (wet-low-emission, WLE), disadvantage: high water consumption, reduced efficiency [5, 21]	Development of DLE combustion for 100% H2 operation Consider space requirement for SCR unit or water injection package

Subsystem	Cause/Difference	Requirement	Challenge
		with water injection, additional space requirement of < 4 m^2 [5]	
	Adiabatic flame temperature	Use temperature-resistant materials inside the burner to avoid reduced lifespan [11] and/or Change of engine cooling system might be required [5, 20, 22]	Develop and evaluate temperature-resistant materials to use inside the combustion chamber Develop adapted cooling system
	Higher water content in the exhaust gas (higher water vapor partial pressure)	Use corrosive-resistant materials in downstream turbine areas to avoid reduced lifespan	Develop and evaluate corrosive-resistant materials for use as rotor material in gas turbines
Heat recovery steam generator (HRSG)	NOx emission reduction via SCR	Space requirements for SCR inside and ammonia or urea tanks, chemical solution pumps and instrumentation outside the HRSG [5] Avoidance or reduction of ammonia leakage [21]	Consider space requirement for SCR unit and ammonia or urea tanks during planning
	Higher exhaust volume flow	Dimension the heat recovery system correctly (enlarge) to ensure consistent performance with 100% H2 operation [4]	Consider (future) space requirements during planning
	Higher water content in the exhaust gas (higher water vapor partial pressure)	Design the heat recovery system accordingly in order to avoid corrosion due to condensation [21]	Consider condensation point in H2 operation during planning
Steam turbine		No significant impact to be expected if the gas turbine can be operated in a similar way to natural gas operation [4]	
Heat extraction		No significant impact to be expected if the gas turbine can be operated in a similar way to natural gas operation	

Subsystem	Cause/Difference	Requirement	Challenge
Steam Cycle Cooling System		No influence to be expected [4]	
Plant-Related Instrumentation & Control		Potentially more sensor signals, higher required processor capacity or additional control cabinets when introducing hydrogen [22]	Consider (future) space requirements during planning
Building	Lower density	Avoid zones with stagnating air exchange rate or consider roof openings [22]	Consider precautions to avoid H2 accumulation early during planning
Fire and explosion protection	Lower density Larger range between lower and upper explosion limit	Adaptation of the entire explosion protection concept necessary for > 10 mol% H2, e.g. larger explosion protection zones [20, 23] Not affected for < 10 mol% H2 [22]	Consider adaptation of explosion protection concept during planning
Plant Operation	Retrofit/fuel switch	Calculate with a downtime of a few weeks to 3-4 months for retrofit to H2 operation [5, 24] Retrofit includes, e.g., new burners and additional systems like a mixing station, hydrogen detectors and monitoring systems [24]	Secure a financial reserve required for the conversion [4]

To summarize, power plant operators need to consider a number of things during the planning phase to ensure that a power plant is suitable for hydrogen or can be converted to hydrogen at a later date. Above all, the supply of hydrogen must be secured at an early stage, which requires large power plants to be connected to the future hydrogen network. It is not necessary to build a completely new type of power plant; instead, appropriately planned gas-fired power plants can be retrofitted and many components can continue to be used. Many of the additionally installed components, e.g. hydrogen detectors, are already available and do not need to be newly developed. However, the core component, the gas turbine, requires further development by the turbine manufacturers. The burner system in particular must be adapted to the properties of hydrogen. The key remaining challenges for the gas turbine manufacturers are

- ensuring a stable, low-NOx-emission combustion of pure hydrogen, including the avoidance of chamber pulsations and the prevention of flashbacks.
- developing and/or testing of thermal-resistant materials inside the combustion chamber and/or adapting the engine cooling system.
- developing and/or testing of corrosive-resistant rotor materials.

As indicated by Figure 1, a retrofit package is therefore likely to include a core gas turbine combustion module replacement, modifications to the instrumentation and fuel control system, modifications to the plant fuel delivery system [25] and additional systems like hydrogen detectors and a mixing station in case of mixed operation with natural gas and hydrogen [24]. Retrofit costs are expected to range between 4% and 15% of the original investment costs, depending on the type and size of the plant [4, 5, 26].

Although the availability of hydrogen is not the direct subject of this study, it is a major challenge for hydrogen projects. Several studies have developed scenarios that depict the expansion of electrolysis capacities alongside solar and wind power plants, and thus the domestic production of green hydrogen in Europe. Agora Energiewende anticipates that domestic green hydrogen production in Europe will match hydrogen supplied by steam-methane reforming in 2030 with around 90 TWh each [27]. According to this reference, there will be almost no more hydrogen based on fossil gas by 2035, as the production of renewable hydrogen will increase rapidly in the following years: 289 TWh in 2035, 520 TWh in 2040 and 769 TWh in 2045. Similar figures result from BMWK's long-term scenario O45-Strom for the 2030s, with 89 TWh in 2030 and 299 TWh in 2035 [3]. Even higher figures are observed in scenario O45-H2, with 100 TWh in 2030 and 366 TWh in 2035, where higher hydrogen demand from industry, buildings and transport drive the expansion path for domestic electrolysis. While 83 TWh (28% of the hydrogen provided) will already be used in the power and district heating sector in 2035 in the long-term scenario O45-Strom (O45-H2: 55 TWh, 15%), Ref. [27] sees only a marginal hydrogen demand from power generation in 2035 and significant quantities expected only from 2040 onwards. As of today, the amount of green hydrogen that will be available in the 2030s is not known. Nor is it certain how high the demand for hydrogen will be. What is certain, however, is that there will be strong competition between different sectors for the demand for a scarce resource.

5 State of the Art - Gas Turbines and Retrofitting to Hydrogen

5.1 Product Portfolio of Gas Turbine Manufacturers

Table 2 shows a selection of today's gas turbine portfolio of the three largest manufacturers Siemens Energy, General Electric (GE) and Mitsubishi. The focus is on heavy-duty and medium-to-large-size industrial gas turbines suitable for power plant operation. All depicted turbines are suited for the 50-Hz European electricity market, similar models exist for the US market with a frequency of 60 Hz. It shows that almost all these gas turbines are capable of co-firing methane and hydrogen with hydrogen contents ≥ 30 vol%. The different upper limits for the H2 content are related to the different firing temperatures and combustion technologies used in the various gas turbines [25]. The largest turbine from Siemens Energy, the SGT5-9000HL, is reportedly already capable of co-firing 50% hydrogen by volume. Even higher hydrogen contents up to 75 vol% are possible with smaller-sized gas turbines like the SGT-800. GE's heavy-duty gas turbines can burn between 30 to 80 percent hydrogen by volume. Medium-sized turbines in the power range from 50 to 150 MW are capable of firing 100 vol% hydrogen. Mitsubishi also offers turbines already capable of firing 100 vol% hydrogen, including the heavy-duty gas turbine M701F with 380 MW. However, so far this is only possible with a so-called diffusive combustion technology, also referred to as wet-low-emission (WLE) or non-dry-low-emission (non-DLE) combustion. In this case, stable and low-emission hydrogen combustion is achieved with the injection of water, steam or nitrogen besides fuel and air into the combustion chamber [28]. This technology comes with two major downsides, i) an efficiency drop due to the diluent injection, usually in the low single-digit percentage range, dependent on the required diluent-to-fuel ratio [29], and ii) a very high diluent consumption, especially for heavy-duty gas turbines. A 60 MW gas turbine running 100% on hydrogen, for example, consumes 20,000 liters of water per hour, and the water must be of suitable quality, which increases operating costs [30]. Therefore, gas turbine manufacturers are currently adapting their dry-low-emission (DLE, also called dry-low-NOx, DLN) combustion technology for hydrogen, which relies on premixing fuel (hydrogen) and air within the inlet nozzle as compared to injecting both fuel (hydrogen) and air unmixed directly into the combustion chamber [28] (see Figure 3). Mitsubihi's DLN technology today enables the co-combustion of hydrogen with a proportion of up to 30% by volume (Table 2).

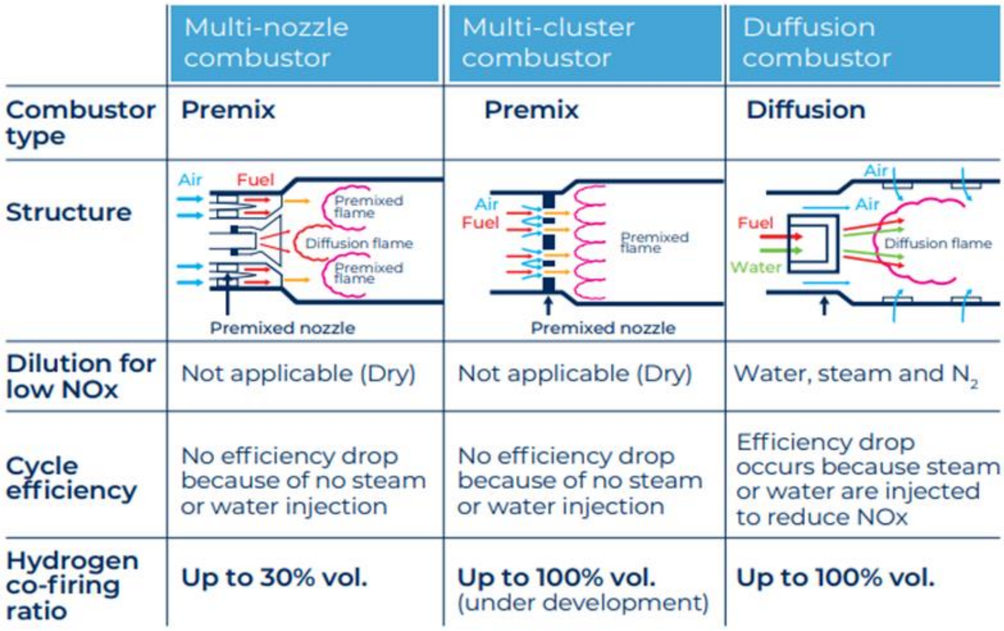
In summary, co-firing limited hydrogen contents is already possible today, but significant CO2 reduction is only possible with very high hydrogen contents ≥ 75% or pure hydrogen combustion [5]. Adding hydrogen to natural gas with a volume share of 30%, for example, only leads to a reduction in CO2 emissions of around 10% compared to 100% methane (Figure 4) [5]. This is due to the significantly lower volumetric heating value of hydrogen compared to methane (see Figure 2). The Kraftwerksstrategie also envisages switching from natural gas to pure hydrogen combustion and not mixed operation. There are already possibilities for 100% hydrogen combustion today, especially for small turbines, but further development of DLE combustion technology is required to replace or retrofit heavy-duty gas turbines in large power plants.

Table 2 Gas Turbine Manufacturer Portfolio

Company	Model	Power (MW)	Max. H2 (vol%)	Efficiency (%)	Refs.
Siemens Energy	SGT5-9000HL	593	50	43	[31]
	SGT5-8000H	450	30	41.2	[31]
	SGT5-4000F	329-385	30	41-41.5	[31]
	SGT5-2000E	198	30	37.6	[31]
	SGT-800	45-62	75	38.4-41.1	[31]
	SGT-750	41	40	40.5	[31]
	SGT-700	35	55	38	[31]
	SGT-600	25	60	33.6	[31]
GE	9HA	448-571	50	42.9-44	[32]
	9F	288	80	38.7	[32]
	GT13E2	195-210	30	38-38.5	[32]
	9E	132-147	100 (Diffusion)	34.3-36.9	[32]
	6F	88	100 (DLN?[1])	36.8	[32]
	6B	45	30 (DLN) 100 (Diffusion)	33.4	[32]
Mitsubishi	M701J	440-570	30	42.3-44	[33, 34]
	M701F	380	30 (DLN) 100 (Diffusion)	41.9	[33, 34]
	M701G	330		39.5	[33]
	M701D	140		34.8	[33]
	H-100	100-120	30	38.3	[33, 34]
	H-25	40	30 (DLN) 100 (Diffusion)	36.2	[33, 34]

[1] The GE 6F gas turbine generally features a DLN combustion system, but it could not be definitively determined within the scope of this study whether the combustion of pure hydrogen was carried out using DLN technology or another combustion system..

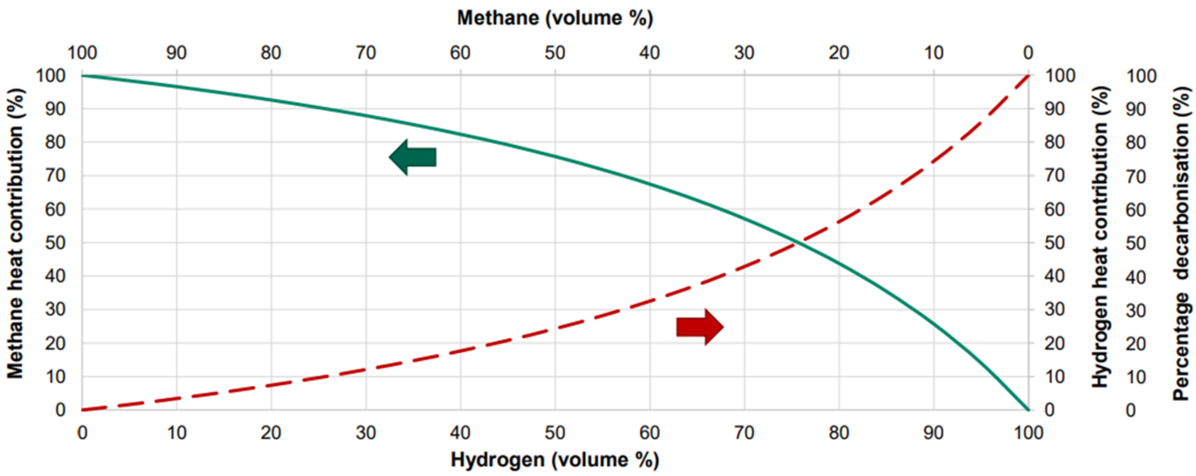
Figure 3 Combustor types overview



	Multi-nozzle combustor	Multi-cluster combustor	Duffusion combustor
Combustor type	Premix	Premix	Diffusion
Structure			
Dilution for low NOx	Not applicable (Dry)	Not applicable (Dry)	Water, steam and N_2
Cycle efficiency	No efficiency drop because of no steam or water injection	No efficiency drop because of no steam or water injection	Efficiency drop occurs because steam or water are injected to reduce NOx
Hydrogen co-firing ratio	Up to 30% vol.	Up to 100% vol. (under development)	Up to 100% vol.

Source: Taken from Ref. [25], after Ref. [28].

Figure 4 Relationship between heat input contribution or CO2 emissions and methane-hydrogen blending



Source: Taken from Ref. [5].

5.2 Existing Research and Development Projects of Gas Turbine Manufacturers

Table 3 summarizes current gas turbine research projects of several turbine manufacturers with the focus on hydrogen combustion. Noticeable are the efforts to develop DLE combustion technology for hydrogen. The prevention of flashbacks is one priority which is addressed by multiple research projects (HYFLEXPOWER, T-Point 2, Kawasaki Hydrogen Road). Kawasaki developed their Micro-Mix-Technology (MMX-DLE) which features several hundred micro injectors for the premixed hydrogen-air mixture to form miniature flames inside the combustion chamber for low NOx emission and to prevent flashbacks [35, 36]. As of 2021, this technology is commercially available for small-sized gas turbines [37]. Kawasaki plans to include this new type of burner in every commercially available gas turbine by 2030 [38].

Similarly, the so-called multi-cluster or multi-tube combustion technology, used by Mitsubishi and GE respectively, utilizes several small flames to stabilize combustion and reduce NOx emission [8, 28, 39]. Mitsubishi has set itself the goal of achieving 100% hydrogen combustion with this technology for the first time by 2025 [34].

Another concept currently adapted for hydrogen is staged or sequential combustion. This concept uses two combustion stages connected in series with different fuel-air mixtures and promises better combustion control [40]. GE plans to further develop their DLN2.6 combustion system, currently used in variations across their F- and HA-class, and combine Micro-Mix/Multi-tube technology with staged combustion [41].

Material research and testing, with focus on corrosive-resistant rotor materials and better understanding of hydrogen embrittlement of steel is conducted by Siemens Energy (and research partners at universities) in the projects Mat4H2Turbine and TurboGreen. Siemens Energy is also increasingly relying on additive manufacturing, which enables new concepts like miniature cooling, makes testing of new components faster and collaboration with research institutes and universities easier [42, 43]. Siemens Energy recently made progress with their DLE combustion technology in small-sized gas turbines (HYFLEXPOWER) and is currently searching pathways for upscaling these developments (HyCoFlex). Specific projects to develop retrofit packages for heavy-duty turbines like the SGT-4000F (4FH2Max) are underway to achieve their goal of 100% hydrogen combustion with DLE technology commercially available across their entire portfolio, including heavy-duty turbines, by 2030 [44].

Overall, the approaches of the manufacturers do not differ fundamentally from one another but are tailored to fit their respective turbine portfolios. Essentially, these are further developments of existing concepts, not entirely new developments. These developments assume that their DLE combustion technology adapted for hydrogen, which has already been partially demonstrated in small turbines, can be transferred to heavy gas turbines and scaled up.

Table 3 Gas Turbine Research Projects

Company	Location	Project Name	Project Goals	Time period	Refs.
Ansaldo Energia		FLEX4H2	- Development of the sequential combustion technology for GT36 H turbine enabling low NOx emision	Jan 23 – Dez 26	[45]
Siemens Energy	Saillat-sur-Vienne, France	HYFLEXPOWER	- DLE technology for SGT-400, up to 12 MW with 100% H_2 - Optimization of the DLE burner design to increase the flow velocity of the fuel-air mixture and prevention	May 20 – April 24	[42, 46]

Company	Location	Project Name	Project Goals	Time period	Refs.
			of flashbacks (instant flashback detection system) - Integration of miniature cooling via additive manufacturing		
Siemens Energy	Saillat-sur-Vienne, France	HyCoFlex (successor project to HYFLEXPOWER)	- SGT-400 gas turbine will be upgraded with an advanced dry low-emission (DLE) H2 combustion system enabling 100% H2 - Create credible pathways for upscaling and replicating the retrofit package	Feb 24 – Oct 26	[47]
Siemens Energy	Mülheim an der Ruhr	BURN4H2	- Achieve hydrogen capability for various burner geometries and physical boundary conditions. - Development of a comprehensive concept for medium-sized (up to 60 MW) and large gas turbines (over 100 MW). - Application of the concept to different forms and performance classes., e.g. SGT-800 (60 MW)	Jan 23 – Dez 24	[48]
Siemens Energy	Berlin	Mat4H2Turbine	- Evaluate A286mod, first produced by Saarschmiede Freiformschmiede GmbH, for use as a rotor material in gas turbines. - Demonstrate the material's resistance under future operating conditions.	Aug 22 – July 25	[49]
Siemens Energy	Mülheim an der Ruhr	4FH2Max	- SGT5-4000F burner development for >50 vol% H2 without power reduction. - Required modifications should be minimal to ensure economical retrofitting for operators and compatibility with existing 4000F fleet	Oct 22 – Sep 26	[50]

Company	Location	Project Name	Project Goals	Time period	Refs.
General Electric		High Hydrogen Turbine-Pro-gramms	- Development of DLN 2.6e combus-tion system featuring an advanced premixer and axial fuel staging technologies - Focus on highly reactive hydrogen fuels and associated combustion dynamics challenges - Develop and test gas turbine com-ponents with natural gas-hydrogen mixtures and up to 100% hydrogen	2022 -	[41]
Kawasaki	Kobe, Japan	Kawasaki Hy-drogen Road	- Developed the world's first DLE combustion system for 100% H2 gas turbines, achieving low NOx emissions without the use of water or steam. - System offers inherent safety against flame flashback - Micro-Mix Combustion Technology (MMX-DLE) commercially available for 1.8 MW - Commercialization for up to 34 MW expected soon (Aug.21)	2021 -	[37]
Kawasaki	Lingen	H2GT-Lingen	- Demonstration project together with RWE - 34 MW gas turbine with 100 % hy-drogen operation - Will use diffusive burner in the be-ginning with water injection - Burner will later be replaced by MMX-DLE technology	2024-	[51]
Mitsubishi	Ta-gasako, Japan	Test Plant T-Point 2	- Increased use of hydrogen in Multi-Cluster Dry-Low-NOx (DLN) burn-ers - Prevention of flame flashbacks		[52]

Company	Location	Project Name	Project Goals	Time period	Refs.
Siemens Energy	Finspång, Sweden	Zero Emission Hydrogen Turbine Center	- Demonstration plant, e.g. for integration of hydrogen in gas turbines	2021-	[44, 53]
Siemens Energy	Mülheim an der Ruhr	TurboGreen	- Developing robust and low-emission burners for gases with high hydrogen content - Researching hydrogen embrittlement	July 2021 – May 2025	[54, 55]

5.3 Assessment of the Market Maturity of H2R Power Plants

In this section the market maturity of H2R power plants is evaluated. As mentioned in the previous sections, the market maturity is mainly determined by the hydrogen capability of the gas turbine. The assessment is based on the comparison of the challenges identified in Chapter 4 and the information provided by gas turbine manufacturers regarding the objectives of research projects and technology roadmaps, as well as other maturity assessments in the literature.

To assess the current technology readiness level of gas turbines for hydrogen operation according to Table 4, we distinguish between small-sized (<50 MW) and heavy-duty gas turbines. Small-sized gas turbines are already being demonstrated in operational environment, for example a 12-MW SGT-400 turbine by Siemens Energy in the project HYFLEXPOWER. The test operation comprised a total of 90 hours on blended fuel, including approx. 10 hours at over 80 vol% hydrogen with more than 4 hours on 100% hydrogen and that being limited by hydrogen supply [42]. This kind of pre-commercial demonstration corresponds to TRL 6 in Table 4. Similarly, on a slightly different scale, the International Energy Agency (IEA) rated the TRL of pure hydrogen gas turbines as 7 out of 11 with a few thousands of operating hours reached at pre-commercial scale [56]. According to the IEA, gas turbines using hydrogen-rich mixtures[2] have accumulated millions of hours of operation at large scale, earning them a rating of 9 out of 11 on their TRL scale and the status of “early adoption” [56].

For heavy-duty gas turbines, such as the SGT5-4000F from Siemens Energy, the technology concept is already formulated and thus achieves TRL 2, as stated by Siemens Energy at the start of project 4FH2Max in October 2022 [50]. Technical validation and demonstration are currently underway in a laboratory environment, and the aim is to demonstrate a prototype (TRL 6, Table 4) by the end of the 4FH2Max project in 2026 [50]. The IEA expects heavy-duty gas turbines in commercial operation with mixtures containing over 50% of hydrogen by 2027 [56].

There is the commitment of GE, Mitsubishi, Siemens Energy and the other members of the association of European gas and steam turbine manufacturers EUTurbines to have 100%-H2 combustion turbines commercially available by 2030 [57]. “Selected models could be available sooner”, said Erik Zindel, Vice-President of Hydrogen Generation Sales at Siemens Energy [58]. The identified challenges from Chapter 4 are being tackled by the gas turbine manufacturers with the research projects listed in Table 3, so that the promised timeline appears to be realistic. There is no need to

[2] The term “hydrogen-rich” usually refers to hydrogen contents of more than 50% by volume, but is not specified here by the IEA.

develop completely new turbines; instead, the focus is on combining and improving existing concepts, which enables faster development [20]. Similarly, Ref. [17] identified “no fundamental roadblocks to achieving 100% hydrogen capability”. A key factor could be the availability of hydrogen, as also pointed out by Ref. [17]. Interestingly, an important part of Mitsubishi's strategic plan is the coupling of hydrogen-capable turbines with hydrogen production plants, as there is a lack of a pipeline network in Japan [17, 34]. As the test time for the combustion of pure hydrogen is limited by the lack of supply, the development time could be extended and the complete validation of the system delayed. Accordingly, Ref. [5] states: “[It] seems to be to consistent across the industry to deliver the first commercial units prior to 2030, however, evidence is not available for drawing conclusions in relation to the expected date of first supply of 100% hydrogen equipment“.

Table 4 Technology Readiness Levels (TRL)

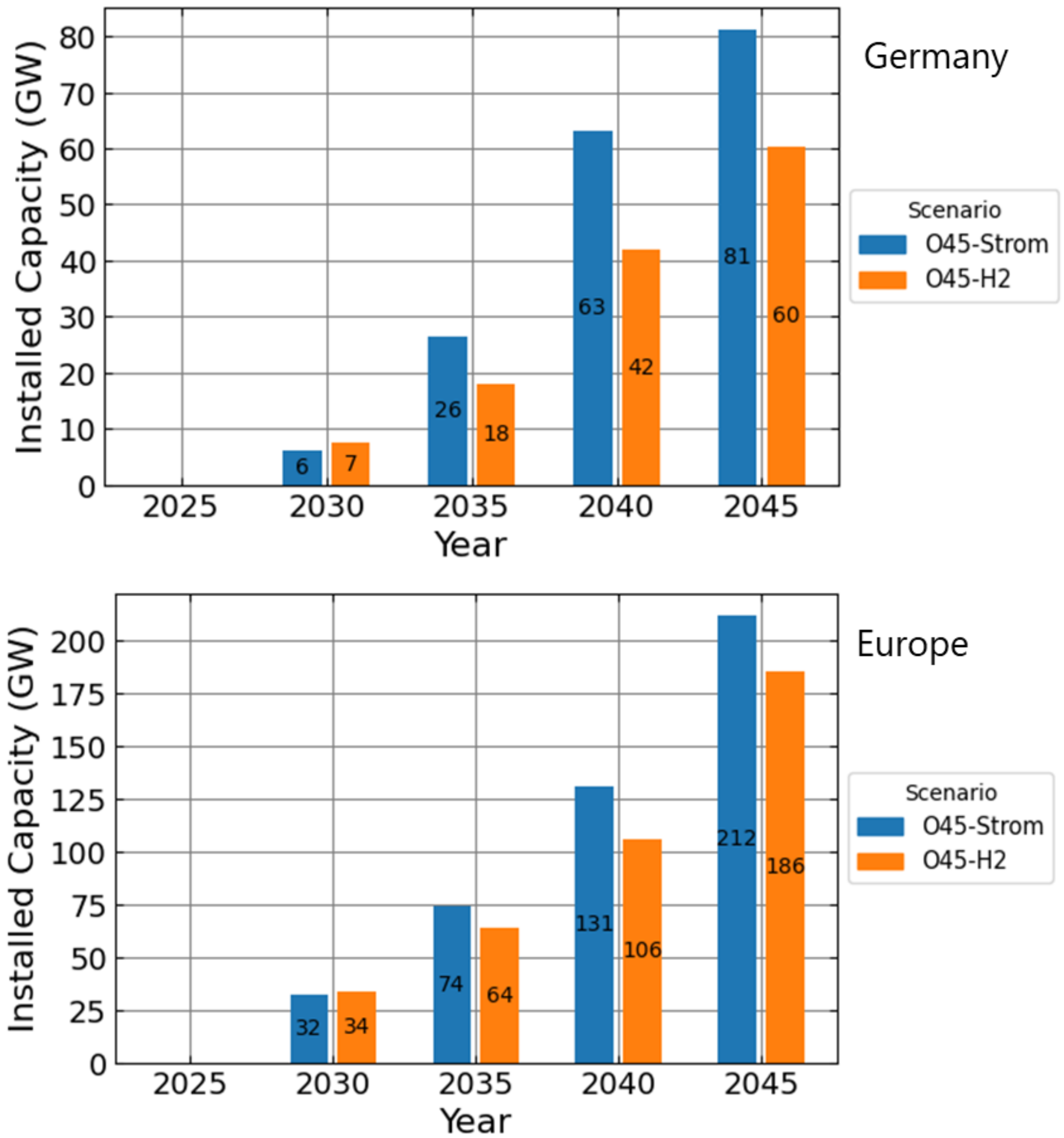
TRL 1	basic principles observed
TRL 2	technology concept formulated)
TRL 3	experimental proof of concept
TRL 4	technology validated in laboratory
TRL 5	technology validated in relevant environment (industrially relevant environment in the case of key enabling technologies)
TRL 6	technology demonstrated in relevant environment (industrially relevant environment in the case of key enabling technologies)
TRL 7	system prototype demonstration in operational environment
TRL 8	system complete and qualified
TRL 9	actual system proven in operational environment (competitive manufacturing in the case of key enabling technologies or in space

Source: Ref. [59].

5.4 Evaluation of Gas Turbine Production Capacities

In this section, the hydrogen power plant strategy in Germany and possible expansion paths for hydrogen power plants in Europe derived from modelled scenarios are reviewed and compared to the production capacities of gas turbines as the key component of such plants. The BMWK long-term scenarios outline a particularly ambitious expansion path for hydrogen power plants and are therefore chosen as a reference to determine whether the production capacities of gas turbines could be a limiting factor.

Figure 5 Hydrogen power plants in the long-term scenarios



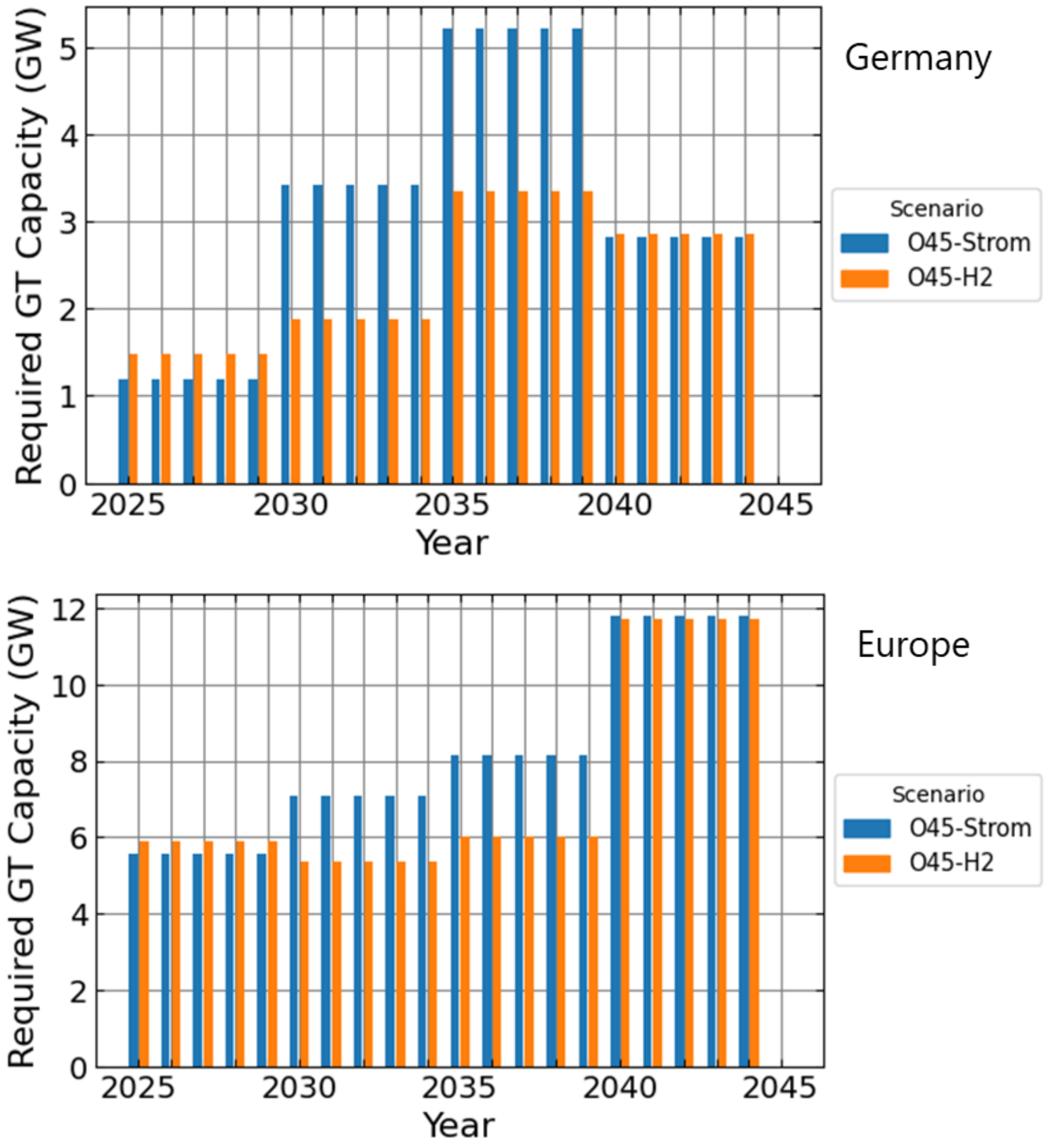
Source: Own representation.

In total, controllable power plant capacities in the amount of 12.5 GW are subsidized by the Kraftwerksstrategie. These planned capacities are also implemented in the latest "Orientierungsszenarien" of the long-term scenarios of the Federal Ministry for Economic Affairs and Climate Action (BMWK). It should be noted, however, that the long-term scenarios do not envisage any retrofit of existing fossil gas-fired power plants to hydrogen operation. All hydrogen power plants in the long-term scenarios are therefore newly built. In Figure 5, the installed capacity of hydrogen power plants in Germany and Europe is shown for the various scenario years. According to these scenarios, around 6 to 7 GW are to be expected in Germany in 2030. The installed capacity will increase over the years and, depending on the scenario, will already amount to between 18 and 26 GW in Germany in 2035. In scenario O45-H2 with a higher hydrogen demand than in scenario O45-Strom and more renewable capacities in Europe to produce hydrogen, the model endogenous hydrogen prices are higher, which makes the reconversion of hydrogen more expensive, so that fewer hydrogen plants are built in this techno-economic optimization. The use cases of hydrogen plants in the long-term scenarios are described in Section 6.2.1.

Similarly, in the Agora scenario, gas-fired power plant capacity in Germany reaches values of 61 GW and 71 GW in 2040 and 2045 respectively [60]. In 2030 and 2035 hydrogen and fossil natural gas fueled power plants combine to 43 and 55 GW, respectively, in this scenario. When natural gas-fired plants are added to the figures in Figure 5, which are built before 2030, very similar capacities are obtained in the long-term scenarios (39-41 GW in 2030, 46-58 GW in 2035) [3]. The Ariadne project delivers a variety of different models and scenarios for climate-neutrality in Germany by 2045 [61]. In most of these scenarios, the installed gas-fired power plant capacities (operated with climate-neutral hydrogen or methane) in 2045 are between 55 and 61 GW. This means that the values are lower compared to O45-Strom, but similar to O45-H2.

Analogous in Europe, including Germany, installed capacities are higher in O45-Strom than in O45-H2 throughout the years with already more than 30 GW in 2030 and between 186 and 212 GW in 2045. Please note that these figures (Figure 5) also include steam turbine capacities in combined cycle gas turbine power plants, which will be neglected for required gas turbine capacities in Figure 6.

Figure 6 Annual required newly built hydrogen turbine capacity according to the long-term scenarios



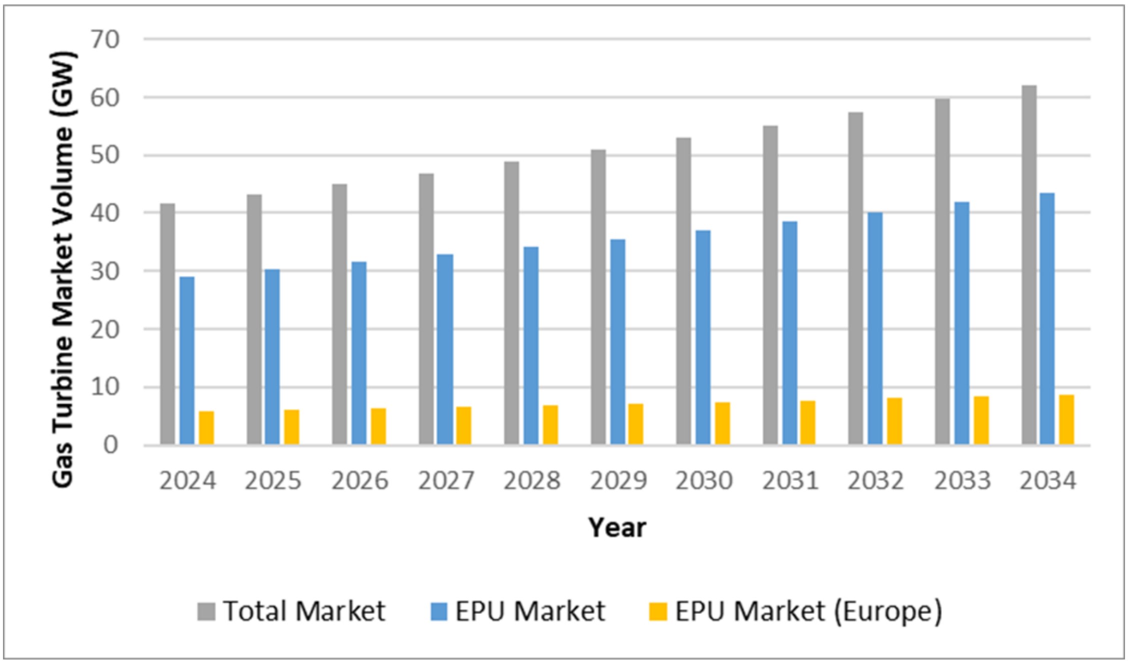
Source: Own representation.

Figure 6 shows the annual required gas turbine capacity of hydrogen power plants assuming that the construction of these power plants is evenly distributed over the five years prior to a specific scenario year, i.e. additional power plants in 2035 compared to 2030 are built in the years 2030 to 2034, for example. Accordingly, each year over the next ten years 6-8 GW of gas-fired power plants are to be built in Europe, which are to be run 100 % on hydrogen from 2030.

Given these ambitious expansion paths for hydrogen power plants in Germany and Europe, which result as a model outcome in the long-term scenarios and other studies, the question arises as to whether the production capacities of gas turbine manufacturers are compatible with this, i.e. whether sufficient turbines designed for operation with hydrogen will be available in time.

It was not possible to obtain precise information on the production capacities of gas turbines in MW per year as part of this study, as these figures are unfortunately not provided by the gas turbine manufacturers. The following assessment is therefore based on market studies that provide forecasts for the coming years for the gas turbine market. Numerous analyzed market studies on gas turbines point to a growing gas turbine market in the coming years with annual growth rates of between 3.3% and 7.5% and a median of 4.1% [62–69]. Global annual sales of gas turbines ranged between 34 and 50 GW in the years 2019 to 2023, with distortions due to the pandemic [70]. To come up with the market volume for 2024 and in order to clear up these distortions we take the market volume of 40 GW in 2019 [70] and assume a growth of 4.1%, resulting in a market volume of 41.6 GW in 2024 (Figure 7, gray bars). Assuming a steady and constant annual growth of 4.1% (median of the market studies) for the next ten years results in a global market volume by power of 62.2 GW in 2034. To make these figures comparable with the annual required gas turbine capacities in Figure 6, we must first consider only electric power utility (EPU) gas turbines. By units, the heavy-duty electric power utility (EPU) gas turbine market is rather small with around 80 turbine per year [71]. However, since these are usually heavy-duty turbines they have a large market share by power of 60-80 % [70, 71]. In Figure 7 we assumed a market share of 70% for the EPU market (blue bars). In 2023, Europe made up around 20% of the market share by region [62], resulting in an annual EPU Market for Europe of around 6 to 9 GW in coming years (yellow bars).

Figure 7 Expected gas turbine market volume by power



Source: Own representation using data from Refs. [62–70].

In principle, these figures correspond to the demand for gas turbines in Europe according to the long-term scenarios shown in Figure 6, if large parts of Europe's market share are dedicated to the production of hydrogen-compatible turbines. As discussed in the previous sections, hydrogen turbines and fuel-flexible turbines in general are an evolution of gas turbines rather than a disruptive new technology. It is therefore to be expected that production capacities can be converted to hydrogen-compatible production with a limited lead time. However, demand for conventional fossil-fuel powered gas turbines will remain high in the 2030s, with markets growing rapidly, particularly in the Asia-Pacific region [68]. This leaves room for a business-as-usual approach by gas turbine manufacturers, which could delay the adjustment of production capacities to hydrogen turbines to a sufficient extent for the European market.

The second condition, that 100% hydrogen capability must be available from 2030, could also pose a problem in connection with the multi-year construction period for such power plants. As discussed in Section 5.3, 100 vol% H2-capable high-performance gas turbines by 2030 seem realistic, but with a typical construction period of three years [72], gas-fired power plants that are ready for operation in 2030 will need to start construction in 2027 at the latest. Especially in view of the fact that there are currently three years between the order and delivery of a heavy-duty gas turbine for Siemens Energy's production site in Berlin [71]. Therefore, the expansion path of hydrogen power plants in the long-term scenario with an installed capacity of more than 30 GW in Europe in 2030, which are operated with pure hydrogen, seems very ambitious. The 500 MW of H2-Sprinter power plants to be operated directly with hydrogen in the coming years according to the Kraftwerksstrategie will probably have to be achieved via numerous plants using small-sized gas turbines, which could be available sooner (see previous section).

Natural gas operation for some of the newly installed power plants and a switch to hydrogen as a fuel between 2035 and 2040, as envisaged in the Kraftwerksstrategie, appear likely. This comes with the drawback of prolonged fossil fuel use and corresponding greenhouse gas emissions. Moreover, from 2035, scenario O45-Strom requires annual newly-built gas turbine capacities of up to 8.2 GW (more than 5 GW of which in Germany). This requires an expansion of gas turbine production capacities or the conversion of further fossil gas turbine production capacities to hydrogen turbines and additional retrofitting capacities for the fuel switch of existing plants in this period in order to avoid the risk of bottlenecks.

6 Planned H2R Power Plant Projects

6.1 Tabular Listing

Table 5 provides an overview of the existing "H2-ready" power plant projects in Germany. A total of 18 projects with many different operators were identified, ranging from individual municipal utilities to large energy supply companies such as RWE, EnBW and LEAG. Some projects are already in the construction phase or even in operation with natural gas, some are in the early planning phase and await details of the tender and the planned capacity mechanism. The operators have not committed to a specific date for the fuel switch, which is understandable given the unclear hydrogen supply situation. Only a few operators have made a vague forecast for the fuel switch to be around 2035. All projects are located close to the planned future hydrogen network (Figure 8). Exact distances to the future hydrogen grid could not be determined for each project within the scope of this study. A maximum distance of 20 km is required for funding under the Kraftwerksstrategie [1].[3] It must be noted that some of the projects listed here, like the three projects from EnBW, are planned and conducted independently of the Kraftwerksstrategie [73].

Table 5 H2R power plant projects in Germany

Location	Type	Operator	Size (MW_{el})	Details/Timeline	Refs.
Leipzig, Saxony	GT_ CHP	Stadtwerke Leipzig	124	- 2023: Start of operation with natural gas - 2x SGT800 gas turbine á 62 MW - First tests (after retrofit) planned for 2026 as part of "BURN4H2", three weeks in summer, hydrogen delivered by truck	[74–76]
Herne, North Rhine-Westphalia	CCGT_ CHP	Iqony	650	- 2022: Start of operation with natural gas - Siemens Energy gas turbine with 15 vol% H2 capability	[77]
Bergkamen, North Rhine-Westphalia	CCGT	Iqony	861	- 2022: Start of planning - Mid 2024: Start of the approval process - 2027: Expected start of construction - 2030: Expected commissioning year - Start with natural gas, expected fuel switch from 2035 - Gas pipeline located 3 km away	[72, 78]

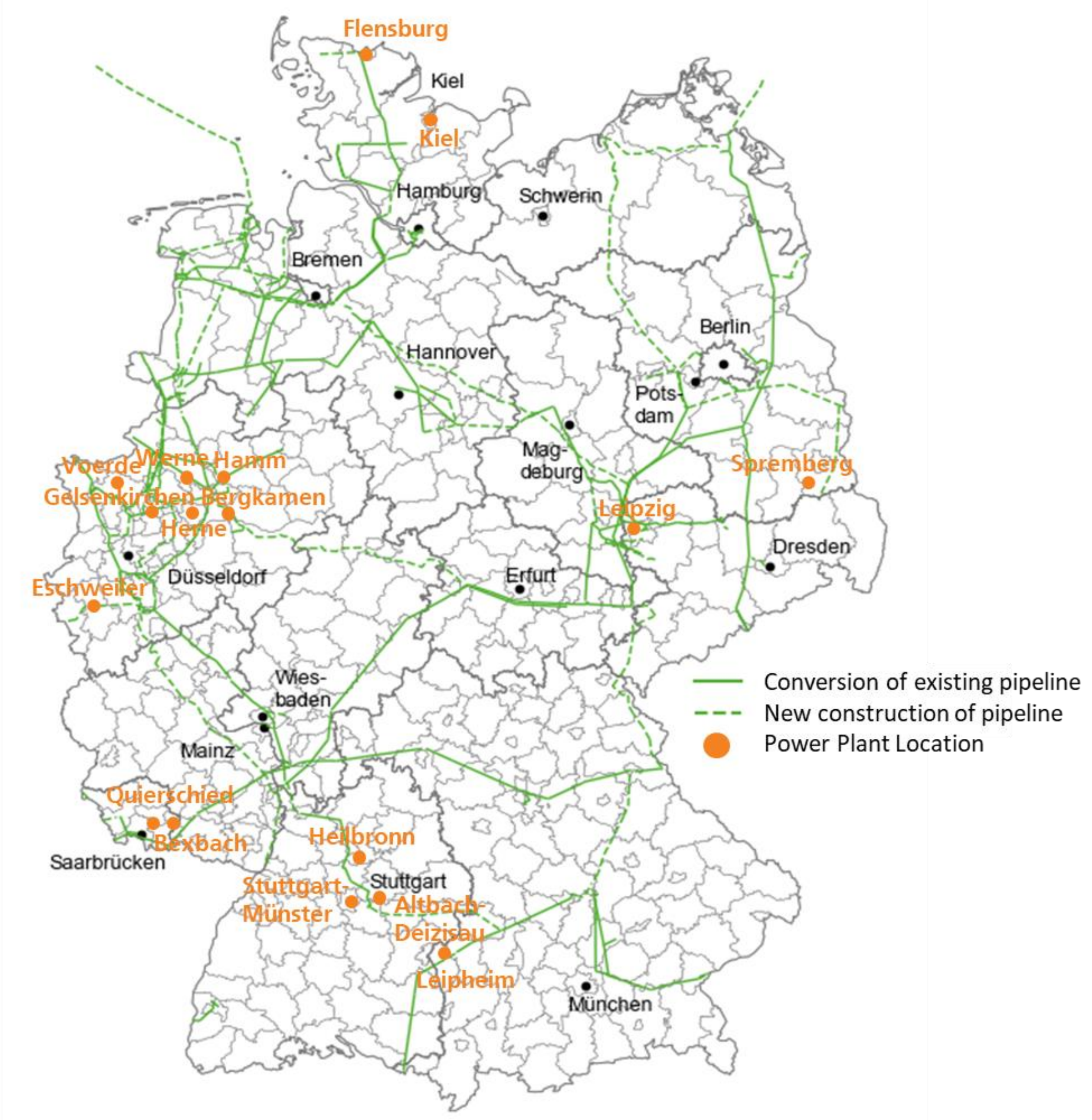
[3] H2 sprinters are exempt from this obligation.

Location	Type	Operator	Size (MW_{el})	Details/Timeline	Refs.
				- Both natural gas and hydrogen pipelines are planned to be established - Gas pipeline might be connected to the hydrogen core network	
Bexbach, Saarland	?	Iqony	900	- Replacement for coal-fired power plant unit on site	[79, 80]
Quierschied, Saarland	?	Iqony	600	- Replacement for coal-fired power plant unit on site	[79, 80]
Heilbronn, Baden-Württemberg	CCGT_ CHP	EnBW	710	- Q4 2023: Expected start of construction - Q1 2024: Start of construction - 2026: Expected commissioning year - Replacement for coal-fired power plant unit on site - Start with natural gas, expected fuel switch in 2030s - Natural gas supply via Süddeutsche Erdgasleitung (SEL), which is currently under construction - SEL will be capable of hydrogen transport and is planned to be part of the hydrogen core network	[81]
Stuttgart-Münster, Baden-Württemberg	CCGT_ CHP	EnBW	238	- 2023: Start of construction - 2025: Expected commissioning year - Replacement for coal-fired power plant unit on site - 2x SGT800 gas turbine á 62 MW - Continue use of 114 MW steam turbine	[82]
Altbach-Deizisau, Baden-Württemberg	CCGT_ CHP	EnBW	750	- 2023: Start of construction - 2026: Expected commissioning year - Replacement for coal-fired power plant unit on site	[83]

Location	Type	Operator	Size (MW_{el})	Details/Timeline	Refs.
Flensburg, Schleswig-Holstein	CCGT_CHP	Stadtwerke Flensburg		- 2023: Start of operation with natural gas - 2028: planned first tests with hydrogen - 2x SGT800 gas turbine	[84]
Eschweiler-Weisweiler, North Rhine-Westphalia	CCGT	RWE	800	- 2030: Expected commissioning year	[85]
Werne, North Rhine-Westphalia	CCGT	RWE	800	- 2030: Expected commissioning year - Ansaldo Energia will supply the gas and the steam turbine.	[86]
Hamm, North Rhine-Westphalia	CCGT	RWE		- Existing power plant site, possibility for new H2-ready power plant	[85]
Voerde, North Rhine-Westphalia	CCGT	RWE		- Existing power plant site, possibility for new H2-ready power plant	[85]
Kiel, Schleswig-Holstein	Gas engine	Stadtwerke Kiel	191	- 2020: Start of operation - 2035: Expected fuel switch to hydro-gen - Retrofit of 20 gas engines to hydrogen required	[87]
Leipheim, Bavaria	OCGT	LEAG	350	- 2030: Expected commissioning year - SGT5-4000F gas turbine - Start as OCGT, upgrade to CCGT possi-ble	[88, 89]
Spremberg, Brandenburg	CCGT	LEAG	450	- 2022: Applications for approval sub-mitted	[89]
Lippendorf, Saxony	CCGT	LEAG	450	- 2022: Applications for approval sub-mitted	[89]

Location	Type	Operator	Size (MWel)	Details/Timeline	Refs.
Gelsenkir-chen-Scholven, North Rhine-Westphalia	CCGT_ CHP	Uniper	140	- 2024: Start of operation with natural gas - 2x SGT800 gas turbine á 62 MW	[90]

Figure 8 Project locations in relation to the planned hydrogen core grid



Source: Project locations added roughly to map of planned hydrogen core grid from Ref. [91].

6.2 Evaluation of Individual Case Studies

In this section, an economic viability assessment is conducted for three selected hydrogen power plant projects from Table 5, representing three different types of hydrogen power plants, i.e. (i) open cycle gas turbine (OCGT), (ii) combined cycle gas turbine (CCGT) and (iii) combined cycle gas turbine with combined heat and power generation (CCGT_CHP). First, use cases of the different plant types are discussed (Section 6.2.1). The assessments in the following sections are based on an energy-only market within the energy-system model Enertile [92] which is also used for BMWK's long-term scenarios. Results are therefore to be considered within the context of the long-term scenarios, which for example require consequent expansion of photovoltaic and wind power plants in coming years, alongside electrolysis and hydrogen storage capacity.

Within an energy-only market, power plant operators are remunerated solely for power and heat generation. This is different in a capacity market, in which (in addition) the provision of power and heat generation capacity alone is remunerated. As mentioned before, a capacity mechanism is planned within the Kraftwerksstrategie and is also anticipated by power plant operators [79]. However, since this capacity mechanism is still under development it cannot be considered here. In addition, some planned details of the Kraftwerksstrategie, such as the limitation of OPEX support to a total of 3200 FLH (4 years) [1], were only published after the calculations for the case study evaluations had been completed.

Based on data from the selected case studies and from the current long-term scenarios O45-Strom and O45-H2, a calculation tool was set up for the assessment with the base year 2018 for cost figures. The specific capacity, the planned commissioning year, and the efficiency for power and heat generation were taken from the individual case study. Fixed and variable operation and maintenance costs were taken from the long-term scenario database for each type of power plant, as well as time-dependent parameters like methane and CO2 prices, available from Ref. [3]. Modell-endogenous market values for electricity, heat and hydrogen are determined for scenarios O45-Strom and O45-H2. These market values are used in the calculation tool as remuneration (electricity, heat) or fuel price (hydrogen).

Hydrogen power plants are planned as a backup for renewable energies, i.e. they are active when there is not enough renewable energy available. During these hours, the market values for electricity in an energy-only market are particularly high. For example, a power plant that only runs in the 100 most critical hours can therefore expect the average electricity market value of the 100 highest electricity market values as revenue. We then take also the average market values for heat and hydrogen for these 100 hours as input for the calculation tool. The input data for a number of full load hours (FLH) of 250, 500, 750, 1000, 1300 and 1600 is determined analogous. In this way, the market values are linked to the number of full load hours. Hydrogen market values, i.e. hydrogen fuel prices for power plants, determined like that range between 107 and 130 €/MWh in 2030 and between 98 and 104 €/MWh in 2045, depending on the number of FLH.[4]

Since modelling is carried out in 5-year steps, data for years in between is interpolated. Further, data from 2045, the final modelling year, is extrapolated constantly until 2065 to be able to cover the full lifetime of hydrogen power plants with data. The economic viability of the power plant with an assumed lifetime of 30 years is finally assessed using the net present value method.

[4] Side note: Scenarios from other studies may show different hydrogen prices. It should be noted here that the assumptions for e.g. interest rates have a strong influence on the hydrogen price. For example, Ref. [60] expects prices of around €110/MWh in 2050 with an assumed weighted average cost of capital (WACC) of 6%, whereas 2% was selected here. In a sector-coupled energy system, where the majority of hydrogen is produced domestically through electrolysis, electricity prices can have a strong influence on hydrogen prices and vice versa. Nevertheless, higher hydrogen prices without an adjustment in electricity prices will result in the profitability of hydrogen power plants shifting to a lower number of FLH. For example, if the price of hydrogen increases by 10% and electricity prices are not adjusted accordingly, the optimal number of FLHs for the case studies examined below is reduced by 100 to 300.

6.2.1 Use cases of different types of hydrogen power plants

In the long-term scenarios Hydrogen CCGT power plants in Germany show numbers of FLH between 600 and 750 (O45-H2) and between 750 and 1000 (O45-Strom), respectively, depending on the scenario year. With an electric efficiency of around 60% they are the most efficient means of converting hydrogen to electricity in the energy system. They mainly run in winter, when the residual load is at its highest, but also occasionally in summer during the most critical hours when there is not enough electricity from renewable energy and other flexibility options like batteries already used. These power plants ensure both seasonally balance (together with hydrogen storage) and short-term flexibility (alongside battery storage) in the energy system. As they only generate electricity, their use can be precisely matched to the electricity demand.

In the long-term scenarios Hydrogen CCGT_CHP power plants with combined heat and power generation range between 1000 and 1150 (O45-H2) and between 1300 and 1450 (O45-Strom) FLH, respectively, depending on the scenario year. With their combined heat and power generation they are the most efficient hydrogen power plants regarding total efficiency, but usually have lower electrical efficiency compared to CCGT power plants without heat generation. As electricity and heat generation are linked, CCGT_CHP plants run almost entirely during the cold season between October and March with very few exceptions. Therefore, with the addition of hydrogen storage, they provide seasonal balance for the energy system. However, as they are usually operated to cover the heat demand, they are limited regarding short term flexibility, especially during summer, when electricity might be needed without any demand for heat.

With an electrical efficiency of approximately 40% OCGT plants are less efficient than CCGT power plants but have also lower investment and operational & maintenance costs. In the long-term scenarios Hydrogen OCGT power plants show numbers of FLH around 100. They are highly flexible and only run in the most critical hours during winter, thus providing short-term flexibility to the energy system, in addition to batteries and other flexibility options. With their low number of full load hours, they are well-suited as back-up power plants to renewable energy sources, especially early on, when hydrogen is short in supply.

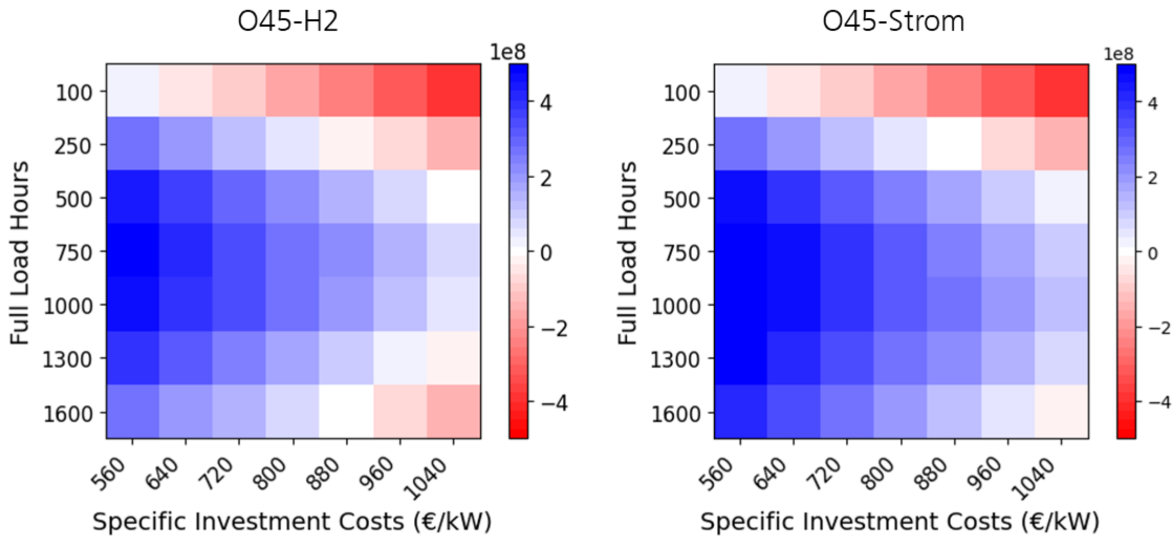
In the following, the FLH figures for the various plant types observed in the long-term scenarios are used as a guideline for system and grid-supporting operation.

6.2.2 Case Study CCGT Bergkamen

For details and the expected timeline of CCGT Bergkamen it is referred to Table 5. One of the key requirements and challenges already to be considered during the planning phase of such a project, as determined in Section 4.2, is securing the (future) fuel supply. This is considered for CCGT Bergkamen, as both natural gas and hydrogen pipeline connections are planned with an existing natural gas pipeline in reasonably short distance (3 km away), which might also be connected to the hydrogen core network. The planned gas turbine is to be capable of 50 vol% H2 as delivered and 100 vol% H2 with a retrofit. Moreover, it is stated that also the conversion of the remaining infrastructure to pure hydrogen operation is already planned [78].

Figure 9 shows the net present value of CCGT Bergkamen for a lifetime of 30 years for both scenarios O45-Strom and O45-H2, depending on the number of full load hours and the specific investment costs. A positive net present value is shown in blue, a negative value in red.

Figure 9 Net present value of CCGT Bergkamen



Source: Own representation.

The investment costs for this project have not yet been determined and are only vaguely estimated at several hundred million euros [72]. Therefore, the variation of the specific costs represents both uncertainties in investment costs and CAPEX funding via the Kraftwerksstrategie. The plant will run on natural gas from 2030 to 2034 and then be retrofitted to hydrogen in 2035, the earliest year envisaged by Iqony for the fuel switch (Table 5), with a downtime of 3 months. Retrofit costs are set to 4% of the original investment costs. This assumption is based on Ref. [4] with data from Refs. [5, 26] for a similar-sized CCGT project.

Net present values are steadily lower with market value data from scenario O45-H2 as compared to O45-Strom. Overall higher hydrogen demand within this scenario results in higher hydrogen market values and therefore higher operational costs for hydrogen power plants. More difficult economic viability for hydrogen power plants in O45-H2 as compared to O45-Strom is also shown by a lower installed capacity of such plants (see Figure 5 in Section 5.4). Nevertheless, in both scenarios for specific investment costs ≤ 800 €/kW the power plant is profitable in a broad FLH range from 250 to 1600 with an optimum between 750 and 1000 FLH. Naturally, this range is reduced with increasing investment costs (or reduced CAPEX funding) to between 500 and 1300 (O45-Strom) and 750 and 1000 (O45-H2) at investment costs of 1040 €/kW, respectively. Noticeably, Figure 9 does not include OPEX funding as intended by the Kraftwerksstrategie, i.e. funding to lower the price difference between hydrogen and methane for up to 800 FLH. For example, for the project at such high investment costs and 1600 FLH to be profitable, OPEX funding must be between 6% (O45-Strom) or 37 % (O45-H2) of the differential costs between natural gas and hydrogen over the entire remaining lifetime of the plant after the fuel switch. While the 6% within O45-Strom would roughly translate to around 1200 FLH to be subsidized over the entire lifetime and thus comply with the maximum number of 3200 FLH set by the Kraftwerksstrategie, the 37% within O45-H2 would exceed this limit by more than double. The large difference in required OPEX funding between the two scenarios is due to the higher hydrogen fuel costs in O45-H2 and the high number of FLH in this example.

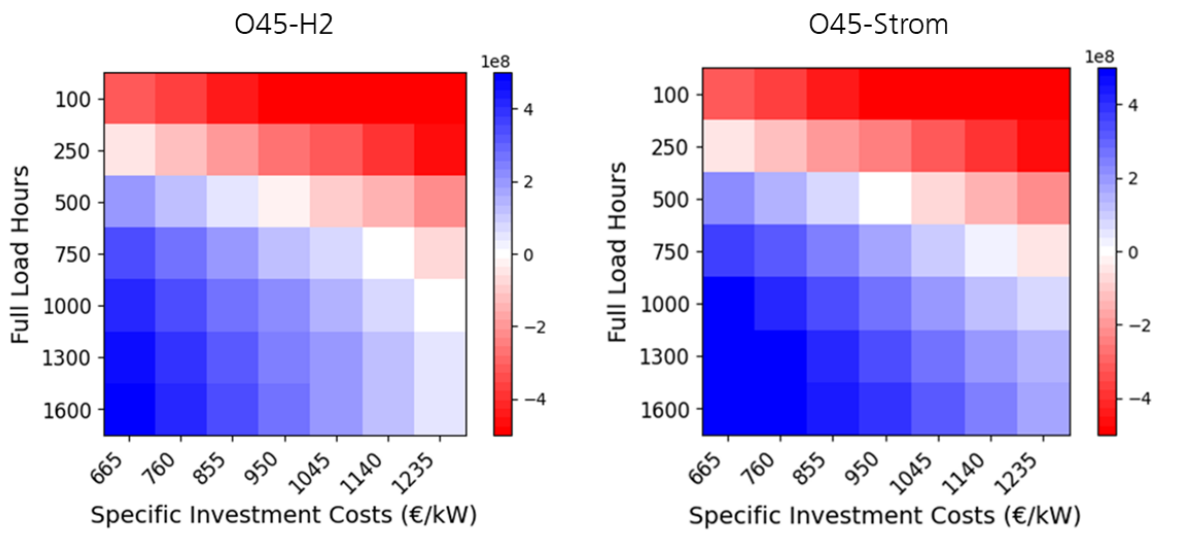
According to the data used for Figure 9 CCGT Bergkamen could be operated profitable in both scenario worlds in a broad range of investment costs without OPEX funding. For lower investment costs (higher CAPEX funding) and/or additional OPEX funding, the plant could also be operated profitably with a very low number of FLH down to 250 or very high numbers of FLH above 1600. Such a configuration, differing strongly from observed behavior of corresponding power plants in the long-term scenarios, could indicate operation that is not optimal for the energy system. Due to its proximity to the planned hydrogen core grid (H2-Kernnetz, switch to hydrogen for pipeline close to Bergkamen planned from 2031 [91]), the future Bergkamen CCGT power plant has a good chance of being connected to the hydrogen grid in the 2030s. The anticipated conversion to hydrogen from 2035 also fits in with the expected turbine production capacities (see Section 5.4) and is in line with the Kraftwerksstrategie. The planned timetable therefore appears realistic, provided that the expansion path of the hydrogen infrastructure comes as planned and sufficient hydrogen is then also available.

6.2.3 Case Study CCGT_CHP Heilbronn

For further details and the expected timeline of CCGT_CHP Heilbronn it is referred to Table 5 and references given there. The CHP plant is planned as replacement for coal-fired plant units on site. The plant is expected to be supplied by natural gas and later by hydrogen via the Süddeutsche Erdgasleistung (SEL) which is currently under construction with sections connecting Heilbronn being operable between 2024 and 2026 [93]. The planned gas turbine is to be capable of 20 vol% H2 as delivered and 100 vol% H2 with a retrofit [94]. It is stated that operation with pure hydrogen requires retrofit measures that are already defined and manageable. However, it is noted that hydrogen operation is not part of the approval process and must be applied for separately before the fuel switch takes place [95].

Figure 10 shows the net present value of CCGT_CHP Heilbronn for a lifetime of 30 years for both scenarios O45-Strom and O45-H2, depending on the number of full load hours and the specific investment costs.

Figure 10 Net present value of CCGT_CHP Heilbronn



Source: Own representation.

Investment Costs for this project are estimated by EnBW to approximately 500 million €, but not finally determined yet [81]. This converts to specific investment costs around 700 €/kW, located at the lower end of the variation in Figure 10. This could be enabled by continue use of existing infrastructure on site like the cooling tower as well as the water treatment systems and the electrical power supply [95]. In this assessment the plant is operated with natural gas from 2026 to 2034 and then retrofitted to hydrogen in 2035 with a downtime of 3 months. Retrofit costs are set to 4% of the original investment costs [4] [5, 26] . 2035 is selected as fuel switch year as EnBW plans to be climate-neutral by 2035 [95]. It should be noted, that KWS funding for newly-built hydrogen power plants would require fuel switch by 2033 (8th year of operation at the latest). However, CCGT_CHP Heilbronn is planned by EnBW independently of the Kraftwerksstrategie [73].

Net present values are again steadily lower with market value data from scenario O45-H2 as compared to O45-Strom. With numbers of FLH below 500 the project is not profitable independent of the specific investment costs. For investment costs ≥ 950 €/kW ≥750 FLH are necessary for positive net present value. At around 700 €/kW, the estimated costs of this project, the plant could operate profitable in a broad FLH range with the optimum at 1600 in both scenarios. Earlier fuel switch before 2035 without any OPEX funding for the cost difference between hydrogen and methane would shift the project to lower numbers of FLH and reduce overall the net present value of the project. For example, with data from O45-H2 and fuel switch in 2033, investment costs must be ≤ 1140 €/kW for the project to be profitable with an optimum number of FLH around 1300 (not shown).

In principle, the market values based on the model framework of the long-term scenarios incentivize system- and grid-supportive operation of CCGT_CHP Heilbronn, i.e. set incentives for FLH values similar to those for corresponding plants in the long-term scenarios. Figure 10 shows that CCGT_CHP Heilbronn has the highest net present values with slightly higher values for FLH. Especially at relatively low investment costs, as estimated by EnBW, made possible by continue use of existing infrastructure, the plant could also be operated profitably in a configuration that is not optimal for the future energy system, i.e., as rather inflexible power plant with many FLH.

Similar to Bergkamen, Heilbronn is reasonable close the H2-Kernnetz with the corresponding pipeline planned to switch from natural gas to hydrogen from 2031 [91]). The Süddeutsche Erdgasleistung (SEL), which is expected to supply CCGT_CHP Heilbronn with fuel, started construction only recently [93], with timely completion required for start of operation in 2026. Planned independently from the Kraftwerksstrategie and without any funding of the cost difference between hydrogen and natural gas, at the moment, there is no incentive for fuel switch to hydrogen prior to 2035, the year of EnBW's self-imposed target of climate-neutrality.

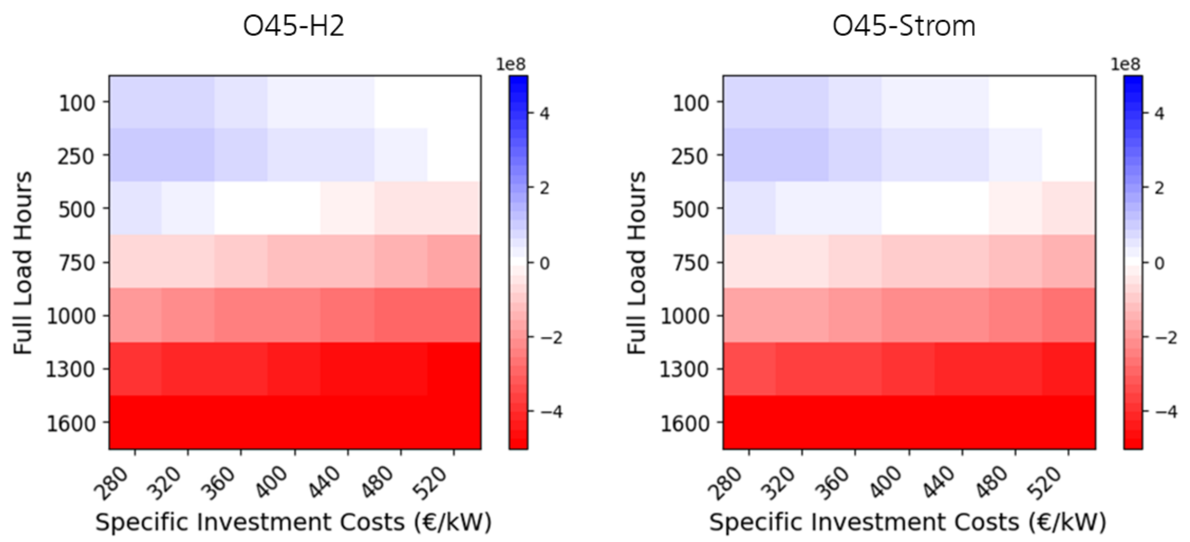
6.2.4 Case Study OCGT Leipheim

This project is in an early stage of planning. LEAG is already operating a natural gas-fired plant on site using a SGT5-4000F gas turbine from Siemens Energy and plans to add an H2-ready OCGT power plant by 2030 [88]. For the new H2-ready plant we assume also a SGT5-4000F gas with an electrical efficiency of 41%. This project was selected to represent OCGT power plants, although it must be mentioned that LEAG could add a steam turbine at a later stage to build a CCGT power plant at this site [89]. This possible step is not considered in the assessment.

As far as the fuel supply is concerned, the OCGT Leipheim is only a few kilometers away from an existing gas pipeline, which is to be converted to hydrogen as part of the H2 core network, but only in the final expansion stage of the current plans by 2032 [91]. For further details and the expected timeline of OCGT Leipheim it is referred to Table 5 and the references given there.

Figure 11 shows the net present value of OCGT Leipheim for a lifetime of 30 years for both scenarios O45-Strom and O45-H2, depending on the number of full load hours and the specific investment costs.

Figure 11 Net present value of OCGT Leipheim



Source: Own representation.

Investment Costs for this project are not determined yet, again the variation of the specific costs represents both uncertainties in investment costs and possible CAPEX funding via the Kraftwerksstrategie. In this assessment we assume plant operation with natural gas from 2030 to 2036 and a retrofit and fuel switch to hydrogen in 2037 with a downtime of 3 months. Retrofit costs are set to 15% of the original investment costs, again based on Ref. [4] with data from Refs. [5, 26]. Relative retrofit costs are higher for this plant as compared to the other case studies since original investment costs are expected to be lower without a steam cycle and a smaller gas turbine. 2037 is selected as fuel switch year to comply with possible funding via the Kraftwerksstrategie (fuel switch in 8th year of operation at the latest).

According to Figure 11, the project is only profitable for low numbers of FLH in strong contrast to the CCGT projects, highlighting the different characteristic of an OCGT power plant. A high number of FLH leads to very high hydrogen consumption due to the lower overall efficiency of such a plant, resulting in very high operational costs. However, the project is profitable (without OPEX funding) with up to 250 and even 500 FLH at low specific investment costs. This is due to very high market values of electricity in an energy-only market in these most critical hours. In both scenarios, O45-Strom and O45-H2, the optimum is at 250 FLH with positive net present values throughout the evaluated range of specific investment costs (280-520 €/kW). To be profitable with 100 FLH, specific investment costs need to be ≤ 480 €/kW. For 500 FLH this range is reduced to ≤ 400 €/kW (O45-Strom) and even ≤ 360 €/kW (O45-H2). Please note that Figure 11 does not include OPEX funding, i.e. funding for the cost difference between hydrogen and methane. For example, for the project to be profitable with 750 FLH, at low specific investment costs of 280 €/kW (possible due to CAPEX funding), OPEX funding must amount to ≥ 21% (O45-Strom) or ≥ 28 % (O45-H2) of the differential costs between natural gas and hydrogen over the entire remaining lifetime of the plant after the fuel switch.

Although OCGT plants have significantly lower numbers of FLH and thus require less hydrogen (despite lower efficiency), like the other projects, OCGT Leipheim is also dependent on the hydrogen infrastructure being expanded in the vicinity of the site. The 350 MW SGT5-4000F gas turbine assumed here at 100% load with 100% hydrogen operation will consume approximately 30 tons of hydrogen per hour. Moreover, hydrogen storage on-site is only viable for small test plant projects with capacities up to 20 MW and short operation periods [5].

6.3 Chapter Summary

The overview of H2-ready power plant projects in Germany in Table 5 clearly shows that most plant operators opt for CCGT power plants. Some of the projects are plants that are specifically designed to replace coal-fired power plants that are being phased out at the site. As a replacement for a coal-fired base load power plant, a CCGT power plant is understandably chosen, as fossil fuel-fired combined cycle power plants can achieve high FLH values of over 4000. However, these numbers will significantly decrease in an energy system increasingly dominated by renewable energies (to about 1000 FLH, as described for hydrogen plants in Section 6.2.1).

Interestingly, within the long-term scenarios, OCGT power plants make up 100% of hydrogen power plant capacity in Germany in 2030. CCGT plants are added in 2035 and CCGT_CHP plants with combined heat and power generation are not added until 2040. This is in strong contrast to currently known projects for future hydrogen power plants (Table 5) with only one OCGT project (which might be converted to CCGT at a later stage). Many plant operators decide in favor of a CCGT (in part even CHP) to use hydrogen most effectively. At first glance, this may make sense for a scarce commodity. However, due to higher investment and fixed operation and maintenance costs, a high number of FLH is required for the profitability of combined cycle power plants (see Figure 9 and Figure 10), thus, a lot of hydrogen is needed for these plants. One reason for the dominant role of OCGT hydrogen plants in the early 2030s in the long-term scenarios is the fact that hydrogen will be in short supply in this period and that it is simply not possible to reach these high numbers of FLH with hydrogen as fuel [4].

While fossil-fueled CCGT power plants with their high number of FLH could be a suitable replacement for coal-fired power plants to ensure their timely phase-out, OCGT power plants are better suited as early hydrogen power plants, which will have a very low number of FLH (due to the limited hydrogen supply). The power plant strategy should take this into account and make a clear distinction between gas-fired power plants, which are planned specifically to replace coal-fired power plants, and early hydrogen power plants. In a sense, this is done by the two pillars of the Kraftwerksstrategie, the decarbonization measure and the measure for security of supply. However, the obligation to have at least 200 FLH to receive funding [1], even for H2-Sprinter that run directly on hydrogen as fuel, could put OCGT plants with an optimal number of FLH possibly below 200 at a disadvantage or even exclude them from the tender.

The Kraftwerksstrategie calls for 500 MW of such so-called H2-Sprinter power plants which will start operation directly with hydrogen. Apart from smaller hydrogen gas turbine demonstration projects (see Section 5.2), no such projects were identified within our research. One major reason for that is the lack of 100 vol%-H2-capable gas turbines. In addition, without a hydrogen grid available yet, the hydrogen for these projects will probably have to be produced and stored on site. These power plant projects will therefore be quite complex and will include not only hydrogen gas turbines, but also electrolyzers and hydrogen storage facilities. On-site electrolysis, on the other hand, requires very low electricity costs.

7 Conclusions

Hydrogen power plants can be a "piece of the puzzle" for the energy transition. If hydrogen will be the main energy carrier for long-term/seasonal energy storage, hydrogen power plants will be needed to convert hydrogen back into electricity and heat in times of high demand and limited renewable energy sources, i.e. especially in winter. Although the operators of such power plants have many things to consider, they are in many ways similar, if not identical, to their fossil counterparts that use natural gas as fuel. However, the key component of gas-fired power plants, the gas turbine, is not commercially available yet for pure hydrogen operation. While small-sized turbines are already being demonstrated in operational environment, heavy-duty gas turbines needed for large-scale power generation are still under development. Hydrogen differs from natural gas or methane in many important properties and presents gas turbine manufacturers with the challenge of ensuring the safe, stable and efficient combustion of hydrogen. Nevertheless, with the commitment of several gas turbine manufacturers to achieve market maturity as soon as possible, it is not a question if but when hydrogen-capable heavy-duty gas turbines will be available. The goal of achieving this by 2030 currently appears to be consistent, as the main challenges are being tackled by manufacturers in ongoing research projects. A key factor here is also the availability of hydrogen, which is required for pilot and demonstration projects. A lack of hydrogen could delay the development and market readiness of hydrogen gas turbines. In the early 2030s, hydrogen-capable gas turbines will likely be commercially available, but hydrogen will be still short in supply. Later, in the period 2035-2040, hydrogen will be increasingly available but will remain a scarce commodity with strong competition for hydrogen supply, e.g. due to industrial demand. During this period, the limited production and retrofit capacities for gas turbines must be sufficiently secured several years in advance for timely retrofiting of fossil-fueled power plants and the expansion of newly built hydrogen plants. On the other hand, if too many gas-fired power plant capacities are built, for example through strong subsidies, there is a risk that the still scarce hydrogen will be withheld from industry or the use of natural gas as a fuel will be prolonged. This would be associated with additional greenhouse gas emissions and would torpedo efforts to achieve an energy transition. In any case, the supply of hydrogen, e.g. via an expansion path for electrolyzers alongside a strong expansion of wind power and photovoltaic, must be secured accordingly in addition to the expansion paths for hydrogen power plants.

These uncertainties (availability of hydrogen (infrastructure) and gas turbines), which affect both the key technological component of the plant (gas turbine) and the top priority for operation (fuel supply), make it very difficult for power plant operators to make an investment decision. This is where the Kraftwerksstrategie comes into play. A planned element such as OPEX funding only for limited FLH is to be welcomed, as it underlines the future role of gas-fired power plants as a backup for renewable energies and other flexibility options. Compared to fossil-fueled power plants, hydrogen power plants will reach significantly lower numbers of full load hours. A distinction should be made between gas-fired power plants that replace coal-fired power plants and ensure coal phase-out (high number of FLH) and power plants that use hydrogen as a fuel as early as possible (low number of FLH), as different types of power plants are suitable for each purpose. More specific funding for OCGT might be necessary to promote pioneering projects ("H2-Sprinter") that can only operate for a small number of hours due to limited hydrogen volumes. On the contrary, the planned element of a minimum number of 200 FLH could hinder or exclude OCGT plants from the tendering process. In general, the details of the Kraftwerksstrategie and the associated capacity mechanism should be worked out quickly to create clear framework conditions for power plant operators.

8 List of Abbreviations

BMWK	Federal Ministry for Economic Affairs and Climate Action
CCGT	combined cycle gas turbine
CCGT_CHP	combined cycle gas turbine with combined heat and power
CHP	combined heat and power
DLE	dry-low-emission
DLN	dry-low-NOx
EPU	electric power utility
FLH	full load hours
GT	gas turbine
H2	hydrogen
H2R	hydrogen-ready
HRSG	heat recovery steam generator
IEA	International Energy Agency
LHV	lower heating value
NOx	nitrogen oxide
OCGT	open cycle gas turbine
SEL	Süddeutsche Erdgasleitung
TRL	technology readiness level
WACC	weighted average cost of capital
WLE	wet-low-emission

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11 References

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