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Retrofit of a combined heat and power plant with gas and steam turbines to hydrogen with special consideration of the balance of plant

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ABSTRACT

In 2020, around 44% of natural gas in Germany was used in combined heat and power as well as in combined cycle gas turbines plants. As district heating will play an important role in future heating planning, the retrofit of these plants to hydrogen is a viable option. This paper analyzes a typical combined cycle power plant, including its balance of plant under consideration of different hydrogen blends. We show that retrofits are limited by the gas turbines in many cases. For instance, the preheater in the fuel gas system must be dimensioned higher than with natural gas. While pressure losses are very low, materials could be a problem due to higher volume flows. Additionally, the higher combustion temperatures in the gas turbine can compensate for possible efficiency losses in the Heat Recovery System Generator (HRSG) and steam turbine making this a suitable approach for electricity-led plants. However, for heat-led plants this leads to a reduction in the district heating output. Therefore, the performance of the HRSG must be considered as a limiting factor for heat-driven plants and the change in flue gas must be analyzed. Currently, hydrogen blends of 20–40 vol.-% appear feasible without major adjustments. The water content in the exhaust gas can also lead to problems in the HRSG and flue gas aftertreatment due to changes in the dew point. For higher hydrogen blends, a plant specific analysis is recommended.

1. Introduction

In Germany, district heating (DH) is predominantly based on co-generation in larger combined cycle gas turbine (CCGT) plants and in smaller, central combined heat and power plants (CHP). The problem with both terms is that CHPs are mostly used for smaller-scale district heating systems with engines, while CCGTs do not directly consider heat extraction for district heating. Therefore the abbreviation CHP-CCGT is introduced for a gas and steam cycle, which are combined with heat extraction for DH.

In 2021, 75% of the heat used in the residential sector was based on fossil fuels. At present, DH had the third largest share after natural gas firing and oil. DH is almost exclusively run by fossil fuels [1]. However, in future, heating networks will also play a major role in decarbonization [2]. Various areas of research on decarbonizing the DH system are available [3–6].

Heat pumps are expected to play a major role in the near future, as they efficiently supply heat through the direct utilization of electricity. But heat pumps are not the exclusive solution. Sayegh et al. [7] highlight this in their review, showing various options for integrating heat pumps in Europe and stating that integrating heat pumps is complex and depends on many criteria.

The picture is also similar in Germany, where almost 1/3 of the heating networks are still operating at a temperature level of above 100 °C [8].

Converting all existing DH networks to modern low temperature networks is cost-intensive. Alternatively, the existing networks could continue at the current temperature level, supplied by existing CHP plants. Only, instead of natural gas, hydrogen could be the new fuel as a bridging technology.

Yu et al. [9] analyzed the potential of CHP with hydrogen production and storage systems. The review shows that fuel cell systems are a viable alternative but are currently too expensive, making blended fuels a more practical option. The technology approach of using natural gas to produce hydrogen with an upstream reforming process seems to be common in the fuel cell area and CHP [9]. Due to the exothermic reaction of the solid oxide fuel cell (SOFC), the endothermic reforming process can be fed with natural gas. Excess hydrogen from the fuel cell is then burned in an afterburner and additional electricity is

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Nomenclature

Acronyms

BDEW	German Association of Energy and Water Industries e. V.
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
CHP-CCGT	Combined Cycle Gas Turbine power plant with district heating usage
DH	District Heating
DLE	Dry Low Emission
DLN	Dry Low NOx
DVGW	German Gas and Water Associations
EoS	Equation of State
GT	Gas Turbine
H-Gas	High Calorific Natural Gas
HP	High Pressure
HRSG	Heat Recovery System Generator
JT	Joule–Thomson
L-Gas	Low Calorific Natural Gas
LP	Low Pressure
M&R	Metering and Regulating
MDPE	Medium Density Polyethylene
MP	Middle Pressure
NETL	National Energy Technology Laboratory
NG	Natural Gas
NOx	Nitrogen Oxygen
NTU	Number of Transfer Units
OGE	Open Grid Europe
PEM	Proton Exchange Membrane
SCR	Selective Catalytic Reduction
SOFC	Solid Oxide Fuel Cell

Symbols

A_{pipe}	Cross Sectional Area of pipe (m^2)
c_p	Heat Capacity (J K/kg)
D	Pipe Diameter (m)
H_o	Higher Heating Value (MJ/m^3)
H_u	Lower Heating Value (MJ/m^3)
L	Length of pipe (m)
$\dot{m}$	Mass Flow (kg/s)
$\dot{n}$	Molar Flow (mol/s)
P	Power (W)
p	Pressure (Pa)
Q	Thermal Power (W)
r_h	Heat Rate (kJ h/kW)
T	Temperature (K)
$\dot{V}$	Volume Flow (m^3 s)
v	Velocity (m/s)
W_i	Lower Wobbe-index (MJ/m^3)
W_s	Upper Wobbe-index (MJ/m^3)
x	Mol Fraction of the Fuel
y	Mol Fraction of the Air

Subscripts

CH_4	Methane
H_2	Hydrogen
O_2	Oxygen
add	Added
Air	Air
el	Electrical
$Fuel$	Fuel meaning Natural Gas blended with Hydrogen
in	Inlet
n	Nominal Condition
$soll$	Outlet of Preheater

Greek

ρ	Density (kg/m^3)

produced via a turbine cycle. This system is called a hybrid system or SOFC-GT [10,11].

Eisavi et al. analyzed the energy efficiency of three different SOFC-GT concepts, with the main difference being the use of one SOFC stack and two SOFC stacks (connected in parallel and in series). It was shown that the variant with two SOFC stacks connected in series has the highest efficiency and, at the same time, the highest carbon dioxide (CO_2) savings. Internal reforming was also assumed here. The afterburner showed the greatest exergy losses in the overall system [12].

Cecere et al. [13] provide an overview of gas turbine hydrogen blending for the electricity market. Two gas turbine systems proved to be particularly interesting. One achieved 70% hydrogen blending by volume, but the complexity of the system is very high. In another system the complexity is lower, but higher blends could not yet be tested. This demonstrates further research into the field of gas turbines is still needed. Additionally the increased moisture content inside the turbine with the blending of hydrogen can impact the hardware lifespan and will lead to higher costs [14].

In Handique et al.'s study [15], a review of 159 papers on distributed hydrogen systems reveal a lack of maturity in the regional-level application of these systems compared to building and district-level systems. Furthermore, the analysis reveals that in nearly 50% of the studies examined, hydrogen was utilized for transportation purposes. Over the past decade, blending hydrogen into natural gas has become a significant aspect of heat supply. The review further highlights an increasing focus on the co-generation of heat and power, reflected in a growing number of publications in recent years. However, this is predominantly employed in engines, as evidenced in the Fichtner et al. [16] study, which asserts that hydrogen blending represents a promising way to power stationary co-generation plants. Nevertheless, modifications to engine control settings are essential to guarantee optimal performance and minimize nitrogen oxide (NOx) emissions. Concurrently, De Santoli et al. [17] demonstrated that with these modifications, the CHP provides less thermal power than with natural gas, despite an increase in system efficiency. Mustafa et al. [18] evaluated the thermodynamic performance of a turboshaft aeroderivative gas turbine. Maintaining a constant turbine inlet temperature has been demonstrated to result in increased thermal efficiency and decreased exhaust temperature with rising hydrogen levels. Conversely, a substantial escalation in NOx formation has been observed at hydrogen levels exceeding 20 vol-%. In the study of Skabelund et al. [19], a Brayton Cycle was analyzed under different conditions with the addition of hydrogen. The results show that the system has an increased thermal efficiency when higher proportions of hydrogen are present. However, it should be noted that the optimum equivalence ratio must be determined anew for each blending level.

The utilization of hydrogen in gas turbines for CHP-CCGT plants has received comparatively little attention. Mati et al. [20] examined the hydrogen retrofit of a CHP unit with a gas turbine to supply energy to a paper mill. In this system, hydrogen was generated locally using a PV-powered electrolyzer, temporarily stored in a storage tank, and subsequently used in the gas turbine. However, the costs remain high, which is why it would have to be subsidized by the government.

Jeong et al. [21] investigated the influence of hydrogen blends for a gas turbine with subsequent utilization of the exhaust gases in a heat recovery system with a steam turbine. The study revealed that the efficiency of the steam turbine decreases with increasing use of hydrogen, but at the same time this can be compensated for in the overall system by the increased efficiency of the gas turbine at higher hydrogen blends. However, the co-combustion of hydrogen can also lead to increased NOx emissions due to higher peak temperatures and higher flame speeds of the hydrogen flame. The authors also found that the optimal hydrogen fraction for co-combustion depends on several factors, such as the type of gas turbine and the operating conditions. Overall, they show that hydrogen co-combustion can improve the performance of gas turbine systems. Nevertheless, more research is needed to optimize the hydrogen content and solve potential problems such as increased NOx emissions.

In their analysis, Mendoza Morales et al. [22] assess the impact of hydrogen on the thermodynamic performance of the GT in off-design operation mode, evaluating three CHP configurations: one pressure-level HRSG with a condensing steam turbine, one pressure-level HRSG with a non-condensing steam turbine, and one pressure-level HRSG without a steam turbine. The study found that at a constant turbine inlet temperature, the gas turbine's thermal efficiency increased in response to the increase in power output, with a relative increase of 2.26%. Furthermore, with higher hydrogen fractions, the flue gas mass flow and heat capacity increased, resulting in an increase in power output.

In another study, Skordoulias et al. [23] investigated a techno-economic analysis of an on-site hydrogen production with a proton exchange membrane (PEM) electrolyzer with direct utilization in a CHP system. The results show that the proposed system has an overall efficiency of approximately 44% and is therefore comparable with other systems. Based on their results, Skordoulias et al. conclude that power to heat technology can be a viable solution to increase the performance of medium-scale CHP systems, especially in countries with high penetration of renewable energy sources. However, they point out that the economic viability of the power to heat CHP systems is highly dependent on variables such as natural gas prices and the cost of hydrogen storage. This research was based in the HYFLEXPOWER project. Here, a 1 MW electrolyzer, an almost one ton H2-tank, and a 12 MW gas turbine (SGT-400) from Siemens Energy, operates with up to 30 vol.-% hydrogen in 2022 [24]. The most recent demonstration in 2023 shows that advanced, dry low emission (DLE) turbines can partly run on up to 100 vol.-%, as well as some blending steps in between [25], but only with modifications.

German municipal utility services want to continue to operate their CCGT plants with hydrogen-based gas turbines. As experience is lacking in this area, Stadtwerke Köln has entered a partnership with Stadtwerke Wien implement the switch to hydrogen. Initial successes were achieved in mid-2023 with 15 vol.-% of hydrogen in full-load operation [26].

From the beginning of 2024 to the end of 2027, in the project HyPowerGT, a new gas turbine technology that can handle hydrogen without dilution wll be investigated [27].

HELIOS is investigating a gas turbine technology that enables high combustion temperatures while minimizing the formation of NOx [28]. The research period extends from the beginning of 2023 to the beginning of 2027.

These four projects show that there is a need for retrofitting.

In the industry, the idea of retrofitting is already well established more. The first TÜV certification for H2-readiness for gas-fired power plants [29] and the first guidelines and position papers on hydrogen retrofit were published in 2023. In a policy briefing from the Reiner Lemoine Institute at the end of 2023, various expert interviews were conducted to provide an overview of the regulatory and technical feasibility of H2-ready power plants. It was found that the fuel gas and gas turbine systems in particular are affected by the retrofit [30]. The vgbe energy e.V. position paper from early 2023 on H2 readiness for gas turbine systems also describes the main problem with these components. In addition, the materials, seals and safety-related issues should not be forgotten [31]. The discussion paper on the H2 process guidelines makes it clear that the quantity of hydrogen is a critical factor [32].

Freitag et al. [33] presents a detailed techno-economic assessment of hydrogen gas turbines, analyzing the effects of using hydrogen instead of natural gas on gas turbine component costs. The results show that a hydrogen gas turbine power plant has an expected cost increase of 8.5% compared to a conventional gas turbine, resulting in an average cost of 542.5 €/kWel for hydrogen gas turbines. The potential for retrofitting conventional natural gas turbines is calculated and the results show that retrofitting existing power plants can be more attractive than building new hydrogen power plants. In addition to the combustion system, auxiliary and safety systems as well as the fuel gas system of a gas turbine plant must be adapted for hydrogen use.

The HYPOS H2-PIMS project was therefore investigating new assessment criteria for the feasibility of hydrogen blends in natural gas pipelines. The focus of the joint work was on identifying possible hydrogen-related damage patterns considering the pipe materials used in the existing natural gas infrastructure, the typical pre-damage, and the existing operating conditions. It has been shown that it is technically feasible and safe to use hydrogen-rich gases in pipelines, provided that appropriate integrity management is in place [34].

In their study, Muhammed et al. [35] show that standardized labeling requirements and regulations are necessary for the safe transport of hydrogen through pipelines. It is crucial to adapt safety measures as well as monitoring systems and detection procedures in the event of leaks. Furthermore, protection of pipelines against hydrogen embrittlement and leakage is required. Islam et al. [36] come to similar conclusions and also show that the transport of hydrogen strongly influences the fatigue properties of steel. It is also pointed out that plastics are less susceptible to problems with mechanical properties, but have a high permeation rate. At the same time, it is emphasized that further research is required. Lo Basso et al. [14] also mention that the transport of smaller volumetric quantities is possible without significantly influencing the pipeline stiffness.

Most publications address the transport of hydrogen through pipelines with high pressures and flow rates. In the available literature, there are only a few studies on lower pressures, which are common at power plant level. In the study by Wang et al. [37], a mathematical model was developed in which both the steady state and the transient state of hydrogen/natural gas mixtures were simulated. The results show that the pressure in the pipeline of 30 bar is already exceeded at a hydrogen blend of more than 30%, which could lead to further problems.

1.1. Scope of this work

Nevertheless, there is a consensus that retrofitting power plants is a rational course of action. To the best of our knowledge, this paper is the first scientific publication to address the whole system of a conventional power plant in conjuncture with direct utilization of hydrogen coming from a pipeline, particularly with regard to extracting heat for the district heating sector and therefore maintaining the same thermal power. As shown in the introduction, there are papers dealing with hydrogen gas turbines and purely economic aspects of retrofitting. In these papers, however, the utilization for a district heating system is sparsely considered, but the overall efficiency of the system is directly addressed, which does not play a primary role for a combined heat and power plant. The effects of hydrogen on the downstream components after the gas turbine are also given little consideration. For the upstream system, only a few papers were found for CHP systems, which meant that results had to be derived from papers on transport pipelines and households.

Our work therefore aims to provide an overview of the problem of hydrogen blending in conventional gas turbine power plants, with a specific focus on a particular thermal power plant. Alongside a review of existing literature, own calculations are performed to better analyze and understand the relevant influences.

A plant that is currently in operation for a district heating network is the subject of this study. The corresponding gas turbine was modeled, based on a Brayton model, in a previous work and was extended for this work to include the calculation of the flue gas composition. The fuel mass flows and flue gas composition have been calculated for different hydrogen to methane ratios (e.g. in Section 2). Specific areas in the BoP are selected in Section 3 and then analyzed in more detail based on the results of the Brayton Cycle (Section 4). To achieve this, own calculations are performed and relevant research is identified that analyzes the issues in more detail. All gas properties were calculated with the GERG-2008 equation of states (EoS).

2. Methods

A typical combined heat and power plant is set up and divided into individual areas. This provides an overview of the various components and can then be better analyzed. The basic differences between methane and hydrogen are described so that the effects of hydrogen can be analyzed. To this end, some of the scientific literature is quoted and some of our own analyzes are carried out using the GERG-2008 EoS, as it calculates real gas properties.

2.1. GERG-2008 equation of state

The GERG-2008 EoS calculates real gas properties of different mixtures by modeling the compressibility factor z based on the Helmholtz free energy, split into parts for ideal and residual fluid. In addition it uses a large amount of experimental data for various mixtures allowing several coefficients to be fitted and enabling different mixtures to be calculated. The pressure and temperature range of GERG-2008 EoS is up to 35 MPa and 90 K to 450 K. Its extended validity range (60 K to 700 K and up to 70 MPa) can be used with a lower accuracy [38]. However, even with this reduced accuracy it still is adequate for modeling natural gas properties with blending of hydrogen. Overall, GERG-2008 EoS is preferred for considerations involving the transport of gases and mixtures [39].

2.2. Volume-, mass- and mole-fraction

In the gas sector, results are usually described using volume fractions. Since the reference to volume is dependent on both temperature and pressure, the designation of these is elementary. However, only a limited number of sources provide this information.

Since the following pages consider significantly different pressure and temperature ranges, we present results in mole or mass fractions. This choice is also necessary because the GERG-2008 EoS requires the components of the mixture to be entered in mole fractions.

The mole fractions of hydrogen in each blending step closely resemble from the volume fractions of hydrogen. The mixture therefore behaves similar to an ideal gas. The volume fraction was based on the standard state as defined in DVGW G-260 (A), i.e., at 273.15 K and 101.325 Pa [40]. As a result, the mole fraction can be regarded as the volume fraction in simplified terms.

2.3. CHP-CCGT plant example

The municipal utility Stadtwerke Bonn operates a district heating network of approximately 121 km with approximately 2,800 recipient points [41]. These figures refer to the year 2022. In the same year, the so-called North CHP-CCGT plant was modernized with a new Siemens SGT750 turbine, providing a capacity of 39.8 MW electrical power (datasheet information found in Table 2). The gas turbine is capable of using up to 20% hydrogen by volume, but is not yet operating with it. The goal is to run the power plant on up to 100% hydrogen by 2035. [42]. The North CHP-CCGT plant also utitizes waste heat from a waste incineration plant. However, since this is not part of the retrofit concept of this paper, a power plant, as illustrated in Fig. 1, was built based on the North CHP-CCGT plant.

The North CHP-CCGT plant is currently supplied with natural gas at a pressure of approximately 34 bar. For safety reasons, various valves protect the supply pipeline from the power plant pipeline. The natural gas supplied is also pre-heated. According to a personal conversation with the head of the electricity and district heating generation division at municipal utility Stadtwerke Bonn, the natural gas pipeline to the gas turbine is between 24 bar and 34 bar (depending on the load) [43]. These values currently still refer to the somewhat smaller SGT600 gas turbine but can serve as a useful comparison.

The exhaust gases from the gas turbine are routed to the heat recovery steam boiler or HRSG. A bypass can be installed here. A bypass plays a decisive role, particularly in district heating operation, as it supports the flexibility and efficiency of the power plant in various operating states. In particular, the bypass is used to flexibly divert steam flows if the normal operating route (e.g. via the steam turbine) is not available or is not optimal. This includes, for example, diverting steam if the pressure and temperature in the HRSG become too high. It is also possible to supply steam directly to the district heating network (e.g. in winter).

In the HRSG, the feed water is heated to various steam temperatures and pressures, allowing the steam to be used in high-pressure to low-pressure steam turbines (HP, MP and LP) to generate electricity. The economizers are used to preheat the feed water to subsequently heat it to steam in the evaporator. In the medium pressure turbine (MP), the steam is cooled via heating condensers to supply the district heating system. After the LP turbine, the remaining steam is cooled down using the cooling water. The heated cooling water can then be used for natural gas preheating. Depending on the load, natural gas is burned in additional burners to obtain more heat output from the HRSG. This is schematically represented in the illustration by the flames below the HRSG. Further, the exhaust gas is fed into the exhaust gas aftertreatment system, where is undergoes dentrification- primarily using ammonia- to reduce NOx emissions and ensure compliance with emission protection limits. The fly ash is then removed from the flue gas. Finally, the desulfurization occurs in which the sulfur dioxides are minimized in the wet scrubbing process.

The open Grid Europe (OGE) supplies Bonn with natural gas (NG). The switch from L-gas to H-gas took place at the end of 2023. Since measurement data for H-gas is not yet available, L -gas data from 2022 is used for further investigations. Its composition is shown in Table 1. The mean values for L-gas from [46] were used, while H-gas data was taken from regulation G-260 (A) [40]. Since the GERG-2008 EoS does not contain data for some components, the small proportion (0.0626 mol.-%) of C_6plus and $neoC_5H_{12}$ was added to methane. The same adjustment was made for H-gas with 0.06 mol.-%. The compositions consist of carbon dioxide (CO_2), methane (CH_4), nitrogen(N_2), ethane (C_2H_6), propane (C_2H_8), isobutane (iC_4H_{10}), butane (nC_4H_{10}), isopentane (iC_5H12) and pentane (nC_5H_{12}).

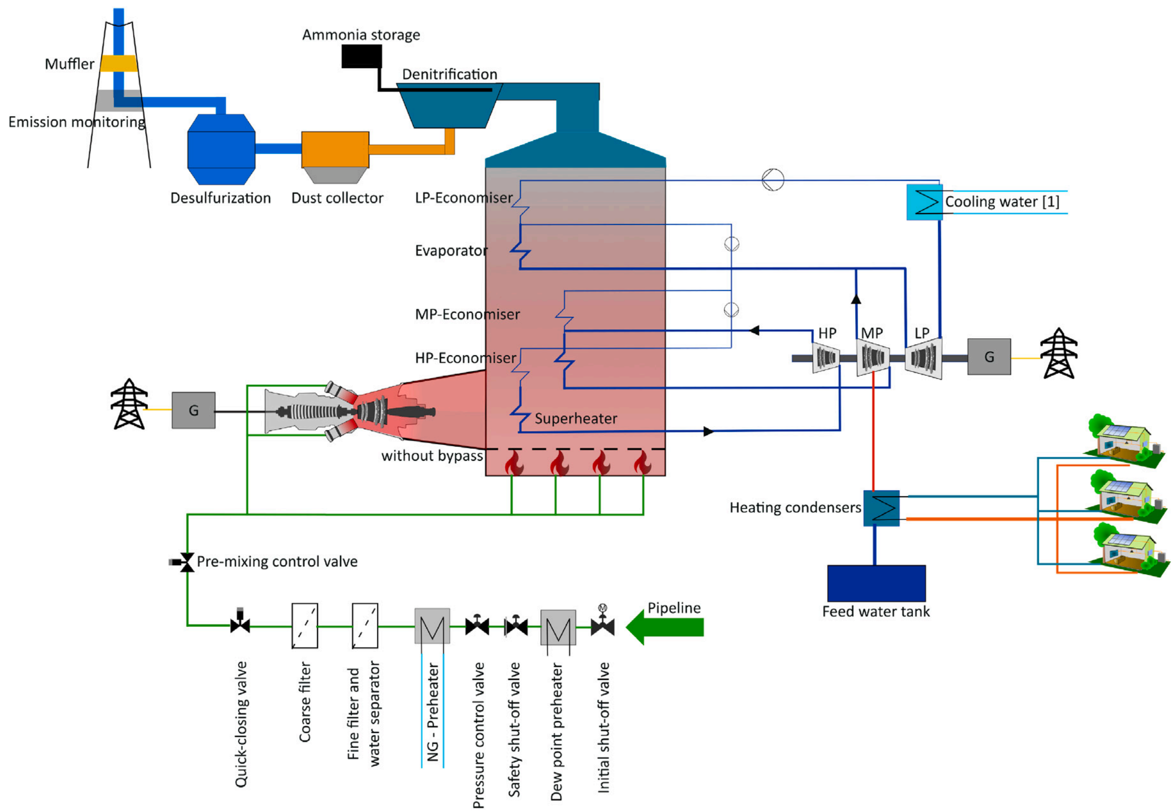

Fig. 1. Schematic illustration based on the North CHP-CCGT. The thin blue lines represent feed water, while the thick blue lines represent the steam phase. HP, MP, LP are the high to low pressure steam turbines. Own work based on [44,45].

Table 1
Used composition of the L-gas and H-gas [40,46,47].

	CO_2	CH_4	N_2	C_2H_6	C_3H_8	iC_4H_{10}	nC_4H_{10}	iC_5H_{12}	nC_5H_{12}
mol.-% L-gas	1.295	83.038	10.316	4.164	0.792	0.136	0.131	0.0345	0.0275
mol.-% H-gas	0.6	90.13	0.28	5.68	2.19	0.9	–	0.22	–
$H_{u,n}$ MJ m_n^{-3}	0	35.88	0	64.35	93.24	123.57	0	0	0
$H_{o,n}$ MJ m_n^{-3}	0	39.82	0	70.29	101.24	133.78	0	0	0

Table 2
Specifications of the Siemens Turbine SGT750 [48].

Property	Value
Gross power output	39.8 MW
Fuel	Natural Gas, liquid fuel, dual fuel
Gross efficiency	40.3%
Gross heat rate	8,922 kJ/kWh
Pressure ratio	24.3:1
Exhaust mass flow	115.4 kg/s
Exhaust temperature	741.15 K

2.4. The gas turbine model

The gas turbine SGT750 was previously modeled for a conference paper (see Ref. [49]) using a simplified Brayton Cycle, which consists of isobaric and isentropic changes of state. The four states calculated are as follows: before the compressor, after the compressor, after the combustion chamber, and after the turbine. The detailed model with the chosen values is explained in the supplementary materials. For the blending stages, methane and not natural gas is used, to improve the comparability, as the compositions of natural gas vary.

Two main differences were made compared to a standard Brayton Cycle, which are explained in the following. Firstly, an energy balance was made around the combustion chamber to calculate the temperature after the combustion. For the energy balance, the massflow of the exhaust gas is needed. Accordingly, the stoichiometric reactions of hydrogen and methane (Eq. (1) and (2)) were integrated. On the basis of these two reactions, the reactants and products of the combustion for each blending stage can be calculated. Consequently, the exhaust gas composition can be calculated.

$$CH_4 + 2\,O_2 \iff CO_2 + 2\,H_2O \tag{1}$$

$$H_2 + \frac{1}{2}\,O_2 \iff H_2O \tag{2}$$

Secondly, the model was integrated with the GERG-2008 EoS, ensuring the calculation of all heat capacities (with the exception of the exhaust gas heat capacity), as well as all densities and molar masses for each blending stage.

In order to obtain the same energy as that produced by the SGT750, it is necessary to calculate the fuel mass flow. This can be achieved by using the values from the datasheet to calculate the fuel mass flow, m_F, via the heat rate r_H, and the electrical power P. The calculation is then divided by the corresponding calorific value (see Eqs. (3)–(4)). For further information and input data, see supplementary materials.

For each blending stage, the low calorific value H_u was calculated with the values from Table 1 and the densities from GERG-2008 EoS converted into kJ/kg.

$$\dot{Q}_{add} = r_h \cdot P_{el} \tag{3}$$

Table 3
Calculation of SGT750 with modified Brayton Cycle model compared to hydrogen as fuel.

Parameter	SGT750	Methane	H_2
Fuel mass flow	–	1.97 kg/s 123 mol/s 98.6 MWh	0.82 kg/s 408 mol/s 98.6 MWh
Air to fuel ratio	–	57	138
Electrical Power	39.8 MW	37.4 MW	38.5 MW
Usable heat of exhaust gas	–	44.3 MW	45.9 MW

$$\dot{m}_{Fuel} = \frac{\dot{Q}_{add}}{H_u} \tag{4}$$

Further assumptions made in the model are:

- Since the same gas turbine and compressor is used, the same air flow rate is assumed as in natural gas operation.
- The heat capacity of the exhaust gas is constant at 1152 kJ/kg K (see supplementary material) as otherwise the turbine outlet temperature could not be calculated.
- Air and fuel temperature are set according to ISO condition.
- Air has a composition of 22% oxygen and 78% nitrogen.
- The exhaust gas only consists of CO_2, H_2O, O_2 and unused nitrogen from air. NOx cannot be calculated with this model.

Table 3 presents the new results of the modified Brayton Cycle with methane and hydrogen.

The model outlined in this section and its supplementary material provide a framework for calculating the fuel mass flow and the exhaust gas composition for each blending stage.

2.5. Comparison of natural gas and Hydrogen properties in power plant design

Hydrogen and NG are used in different ways in industry and chemistry. NG is made up of several components but mainly consists of around 80%–99% of methane.

Hydrogen properties. A major difference between methane and hydrogen is the molar mass, which is about 18 times smaller. Therefore it is essential to be precise when describing volume fractions (vol.-%) or mass fractions (mass-%).

This difference in volume and mass fraction is illustrated in Fig. 2 which shows a non-linear behavior between volume- and mass-fraction of the mixture. This means that the CO_2 savings are also non-linear. In addition, it is necessary to check the most appropriate proportion for each component. The density changes depending on the mixing ratio, the temperature, and the pressure. Therefore, for each pressure and temperature level the density was calculated by GERG-2008 EoS. Hydrogen has a higher energy content per unit mass than natural gas. One kilogram of hydrogen therefore contains more energy than one kilogram of natural gas. Due to the large differences in density, the energy content per unit volume is exactly the opposite. This property has a direct influence on the required mass and volume flows in the power plant, all the way up to the gas turbine.

Combustion of Hydrogen. In addition to the different chemical properties, hydrogen also has fundamentally different combustion characteristics.

Cecere et al. [13] illustrate the differences in flame speeds for hydrogen admixtures, showing that hydrogen use can increase flame speed by up to 30%. This increase leads to several problems, including unstable combustion and therefore higher risks of flashbacks and material damage [50].

A coefficient for describing stable combustion is the Lewis number. The Lewis number describes the ratio of thermal conductivity to mass

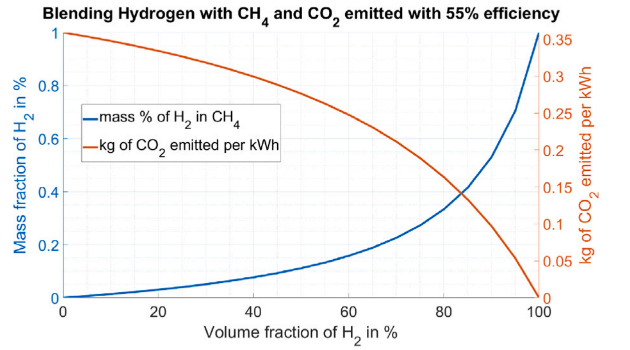

Fig. 2. Volume to mass fractions for various hydrogen to methane blending stages. The orange curve shows the emitted kg of CO_2 per kWh as a function of the blending stages with a efficiency of 55% (own work based on [9]).

diffusivity. If the Lewis number is less than 1, the significantly faster mass transport leads to an unstable flame. A higher mass diffusivity can lead to locally different fuel mixtures and thus to very different combustion or flame fronts. This sometimes leads to much higher flame speeds. This happens when a certain flame radius is reached [51].

Due to the higher flame speed, the flame shape changes and becomes more compact towards the burner. In [52] different flame shapes of a premixed mixture from pure methane to 26 vol.-%, hydrogen blends are shown. Together with the higher adiabatic flame temperature of 150 K to 200 K more, this results in stronger heating of the surfaces, which can lead to flashbacks as the hydrogen can ignite on the surface itself. In addition, unburned hydrogen can flow back into the premixing zone [51].

Wobbe-index. The Wobbe-index is a measure used to describe the performance and interchangeability of different fuel gases. If two gases have the same Wobbe-index, the same amount of power is delivered. Basically, there is the upper $W_{s,n}$ and lower Wobbe-index $W_{i,n}$, which is calculated using the higher (H_o) and lower heating (H_u) values and the fuel $\rho_{Fuel,n}$ and air $\rho_{Air,n}$ densities under norm-condition. All values refer to the norm state of 273.15 K and 101.325 kPa. The Wobbe-index is defined as follows [53]:

$$\begin{aligned} W_{s,n} &= \frac{H_{o,n}}{\sqrt{\frac{\rho_{Fuel,n}}{\rho_{Air,n}}}} \\ W_{i,n} &= \frac{H_{u,n}}{\sqrt{\frac{\rho_{Fuel,n}}{\rho_{Air,n}}}} \end{aligned} \tag{5}$$

Different compositions of fuel gases result in locally fluctuating densities of the gas and therefore changes in the Wobbe-index. The Wobbe-index is used to adjust the devices to their required air demand, which is approximately proportional to the Wobbe-index change. The relative density has an influence on the measurements of reservoir flow meters. Here, the gas volume flow is adjusted according to the error in the designed values of the device. The Wobbe and relative density bandwidths are defined so that proper operation for different combustions can take place [54]. Each country has defined its own bandwidths. In Germany, the DVGW has regulated the permissible ranges in its Code of Practice G-260 (A) and these are listed in Table 4 for natural gases. The relative density may be in a range between 0.55 m^3/m^3 and 0.75 m^3/m^3 [40].

Joule-Thomson effect. In most gases, expansion of the gas leads to cooling of the mixture, whereas compression leads to heating. The Joule-Thomson (JT) effect describes the heating or cooling of a real gas when the pressure changes due to throttling or compression (the effect is not present in an ideal gas). The JT coefficient indicates the direction

Table 4
Upper and lower Wobbe-index limit values for H-gas and L-gas according to G-260 (A) [40].

	$W_{i,n}$ in kWh/m^3	$W_{s,n}$ in kWh/m^3
H-gas	13.6	15.4
L-gas	11.0	13.0

Table 5
Comparison of hydrogen and methane gas properties [13].

Property	Hydrogen	Methane
Molecular Weight [g/mol]	2.016	16.04
Density[a] [kg/m^3]	0.0838	0.6512
Self-Ignition T [K]	845–858	813–905
Flammability range in Air [vol.-%]	4–75	5–15
Flammability range [ϕ]	0.1–7.14	0.4–1.67
Stoich. Composition in air [vol.-%]	29.53	9.48
Adiabatic Flame Temperature [K]	2318–2400	2158–2226
Lower Heating value [MJ/kg]	118.8–120.3	50
Higher Heating value [MJ/kg]	141.75	55.5
Lower Heating value[a] [MJ/m^3]	10.78	35.8
Higher Heating value[a] [MJ/m^3]	~12.75	39.72
Wobble-Index[a] [kWh/m^3]		
Stoichiometric air-to-fuel ratio (kg/kg)	34.2	17.1
Stoichiometric air-to-fuel ratio (kmol/kmol)	2.387	9.547

[a] At 273.15 K and 101.3 kPa.

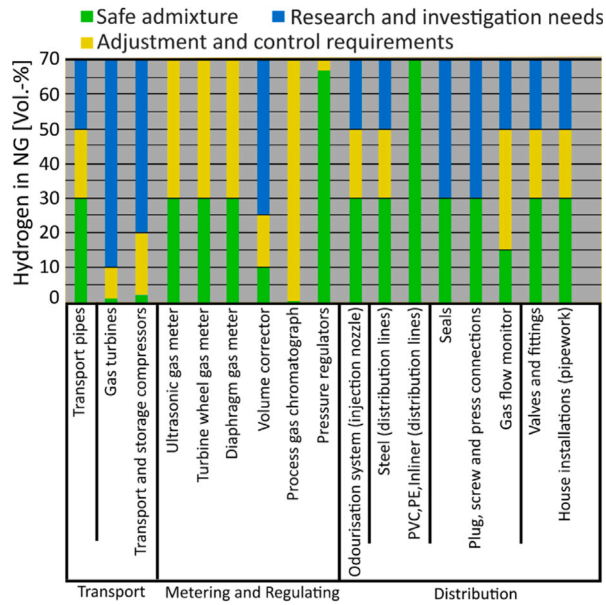

Fig. 3. Overview matrix from 2013 on the possible use of various gas-relevant components depending on the possible addition of hydrogen. For this illustration, three out of five areas were extracted from the original [56] and translated into English by the author.

in which the temperature change takes place (at given temperature and pressure). If the coefficient is greater than zero, a decompression leads to cooling of the gas. If the coefficient is less than zero, the gas heats up with decompression [55].

In contrast to methane, hydrogen has a negative JT coefficient within the pressure and temperature ranges typical of a CHP-CCGT plant. This means that when hydrogen expands, it heats up. Table 5 provides an overview of the various properties of methane to hydrogen.

3. Retrofitting R&D needs and costs

The various areas of retrofitting were selected in accordance with the position papers and the techno-economic overview from Freitag et al. [30–33]. These papers were used to pre-analyze different components, as higher costs usually result from problems within the components.

In 2013, the DVGW examined concepts for feeding hydrogen and methane into the natural gas grid. An overview matrix for various components of the natural gas grid was created based on national and international findings as well as the DVGW's own investigations. A distinction was made between transport, gas storage, metering and regulating (M&R), distribution and application. In addition, a classification was made into safe blends, adjustment and control requirements, and research and investigation needs [56].

In Fig. 3, the areas of transportation, M&R and distribution have been highlighted and translated by the authors from the original into English. It can be seen that valves and metering require no or only minor changes of up to 30% hydrogen by volume. The same applies to pipelines and materials. According to this report, seals also appear to tolerate higher hydrogen blends. As this overview matrix provides only a rough overview and new findings have emerged since 2013, each case must be evaluated individually.

The Roadmap Gas 2050 has shown that a hydrogen content of 20% by volume can be achieved with little effort for gas appliances in households and CHP units. It also mentions that the relative density limits can be lowered to 0.45. In addition the tightness of the connections (threads, press and sliding sleeves) was also proven to be up to 100% [57,58]. The vgbe energy and BDEW Hydrogen process guidelines specify two blending levels for power plants [31,32]. The first blending stage is 17% by volume and the second blending stage is 52% by volume. For each stage, the expected costs are given as a percentage of the new acquisition costs of a 100% natural gas turbine. A distinction is made between new plants and existing plants. The costs for the first stage are classified as low (3%–10% for new plants and 6%–12% for existing plants). For the second blending stage (from 17% to 52% by volume), additional costs of 5%–15% for new plants and 15%–25% for existing plants are expected. At the same time, the changeover to 52% by volume is considered technically feasible in most cases. Significant additional costs are expected for the next stage up to 100% by volume. Depending on the technology and economic viability, further intermediate steps must be considered [32].

The European Association of Manufacturers of Gas and Steam Turbines, known as EU Turbines, have made a further subdivision for the classification of the term H2-Ready. Level C is achieved with up to 10 vol.-% hydrogen, Level B with up to 25 vol.-% and Level A with up to 100%. Each level is divided into 3 sub-levels based on costs [59]. An overview is shown in Table 6. According to the EU Turbine website, a catalog of which modification falls into which level is currently in progress.

Freitag et al. [33] provide a comprehensive techno-economic analysis of hydrogen gas turbines, focusing on the impact of substituting hydrogen for natural gas on the costs of turbine components. Their findings indicate that hydrogen-based gas turbine power plants are expected to have an 8.5% higher cost compared to conventional gas turbine plants, leading to an average cost of 542.5 $€/kW_{el}$ for hydrogen turbines. The study also evaluates the feasibility of retrofitting existing natural gas turbines, highlighting that retrofitting may be a more cost-effective solution than constructing entirely new hydrogen power plants. Additionally, the adaptation of the combustion system, auxiliary and safety systems, as well as the fuel gas system, is necessary to enable the use of hydrogen in gas turbine plants. The classification that is most appropriate for investigating the power plant is dependent upon the component that is under consideration. Consequently, no generalized limits for hydrogen blends are considered in this context; instead, an overview of the existing research and issues is provided, together with a critical analysis of the effects caused by blends, based on the results of our own calculations.

Table 6
Overview of blending ratios of hydrogen for gas turbines according to EU Turbines [59].

	Level A - 100 vol.-%	Level B - 25 vol.-%	Level C - 10 vol.-%
Category 1 No substantial modification, up to 5% of overall costs of new power plant	A1	B1	C1
Category 2 Minor upgrading necessary, up to 10% of overall costs of new power plant	A2	B2	C2
Category 3 Upgrading technically and economically possible, up to 20% of overall costs of new power plant	A3	B3	C3

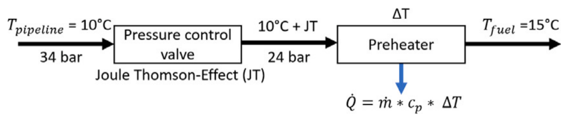

Fig. 4. Assumed scheme and values of the fuel gas system to analyze the JT effect and preheater dimension (own work).

4. Changes with different blends of Hydrogen in plant

Based on [30–33], the following areas were defined: the fuel gas system (supply from pipeline to gas turbine), the gas turbine, the HRSG, and the exhaust gas aftertreatment.

The mass flows and fuel consumption are required for the consideration of the fuel gas system and flue gas aftertreatment and the resulting exhaust gas quantities and compositions. Therefore the model of the gas turbine was used (see Section 2.4).

4.1. Fuel gas system

There are two important aspects to consider in the fuel gas system: the pipework system with its materials and the throttling of the gas from the pipeline to the power station with preheating of the gas. This study focuses on these two aspects.

Preheater. The JT effect plays a decisive role in the throttling of gases (see Section 2.5). When hydrogen is added, the effect is gradually reversed so that the gas heats up when the hydrogen is throttled. The preheater is currently used in the fuel gas system to raise the temperature of the cooled natural gas. This is done partly to improve efficiency and partly to minimize droplet formation in the gas turbine.

The numerical study by Zhang et al. [60] and Li et al. [55] show that the JT characteristics for hydrogen blends differ significantly from those of pure natural gas flows. At pressure reductions of around 10 bar, the Joule-Thomson coefficient can be up to 50% lower, depending on the hydrogen content, which leads to a lower temperature drop. At 30 mole-% hydrogen and a pressure drop of 10 bar, the gas has decreased by 1.4 K [60]. This finding is particularly relevant for CHP systems, in which the pressure control of hydrogen not only influences the efficiency of heat recovery, but also reduces the risk of condensation and icing. Therefore, the JT effect for the described power plant is analyzed below in conjunction with the preheater.

Fig. 4 shows the system with the assumed pressure and temperature levels. Before throttling, the fuel exits from the distribution pipeline with a ground temperature of approximately 10 °C and a pressure of 34 bar. The pressure at the power plant level is reduced to 24 bar. The preheater should heat the fuel to 15 °C (ISO-Condition).

The dimensioning for the preheater can be estimated in a simplified form using $\dot{Q} = \dot{m} \cdot c_p \cdot \Delta T$, with the heat capacity c_p of the gas and the temperature difference before and after the preheater ΔT (see Fig. 4). At each blending stage, the inlet temperature of the preheater changes due to the JT effect. The mean value before and after the throttle was calculated for the JT coefficient with the values based on data from the Gerg-2008 EoS. The mass flow is known from the Brayton model. In addition the heat capacities of the fuel mixture were also determined from GERG-2008 EoS. Fig. 5 shows the results for different blending stages. The left axis shows the relative changes compared to 100% methane for the proportions of the mass flow, the heat capacities and the overall power. The right axis show the absolute temperature difference ΔT. With 100% methane the gas will cool to 5 degrees Celsius due to the JT effect, resulting in a temperature difference of 10 °C. With an increased hydrogen share, the temperature difference decreases because the gas cools less. At a ΔT of 5 °C, the gas neither cools down nor heats up. As anticipated, the temperature difference between the inlet (based on JT effect) and outlet (constant 15 °C) of the preheater decreases with an increase in the hydrogen content. At nearly 95% up to 100% of hydrogen by volume, the gas will heat up slightly. This can be seen as the graph lies under the temperature difference of 5 °C. Because of the increase in the lower heating value, the needed massflow to obtain the same energy output, decreases. With the decreasing ΔT and massflow, the preheater would need less power to heat the fuel up to 15 °C. However at the same time, the heat capacity increases sharply with increasing hydrogen content (blue dotted line). This means the preheated volume needs to be up to 122% larger than in pure methane operation (see blue solid line).

Since the gas remains largely unchanged at 100% hydrogen and the preheater has to be dimensioned higher at the same time, this raises the question of whether a preheater is still necessary at all or whether the almost 10 degrees are sufficient for hydrogen operation. This needs to be investigated further, particularly with regard to the effects of different fuel temperatures on the gas turbine and the exhaust gas temperatures for the steam turbine section. The impact is considered to be quite low, which means that the heat previously used for the preheater could be utilized elsewhere.

Pressure losses and materials. As Fig. 5 shows, the mass flow decreases as the hydrogen content increases. In order to provide the same amount of energy for the gas turbine, the volume flow and thus the velocity must increase, which simultaneously increases the pressure loss within the pipelines. This drop in pressure creates a major problem, particularly for the transport pipes.

To compensate, the compressors needs to be significantly more powerful to deliver the same energy as with natural gas [56,61]. At the higher speeds of hydrogen, problems can arise regarding both the material and noise development. This is why limit speeds for natural gas were introduced. Mischner [62] extrapolated these limit speeds using natural gas data and initially found that significantly higher speeds could be permissible with hydrogen, as the limit speed can be adjusted accordingly.

As part of the HYPOS H2-PIMS project, the suitability of natural gas pipelines for hydrogen blends was investigate [34]. In HYPOS H2-PIMS the results of the NaturalHy project were used to investigate material suitability. The findings indicate that plastic deformation is the primary cause of damage, while hydrogen embrittlement plays only a minor role in crack formation. The influence of hydrogen embrittlement is

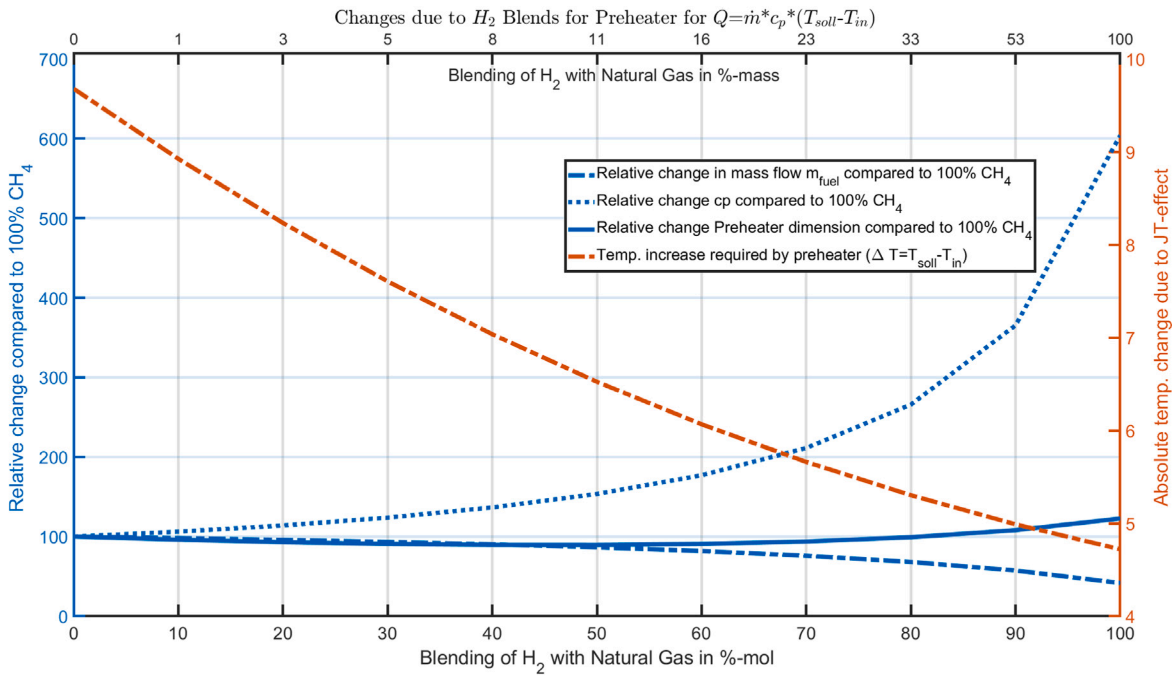

Fig. 5. Results from the calculation of the preheater dimensions and values with different blending stages of hydrogen in %-mol (own work).

more pronounced in weld seams and existing cracks. As pressure and hydrogen content increase, the critical (still allowable) crack depth decreases, which has a negative effect. At pressures between 20 bar and 30 bar and with 100% hydrogen, the behavior is comparable to that of natural gas. Above 50 bar, the critical crack depth is 30% lower than for natural gas. For materials commonly used in Germany after 1975, such as X70 and X25 steel, the maximum total crack growth within the range lays around 25% and 50% hydrogen respectively. With the addition of oxygen, 100% of hydrogen is possible. Both oxygen (O2) and carbon monoxide (CO) inhibit hydrogen embrittlement. But these gases are not always desired as the result is shorter maintenance intervals.

Islam et al. [36] reach analogous conclusions and additionally demonstrate that hydrogen markedly impairs the fatigue characteristics of steel. It is highlighted that although plastics are less vulnerable to mechanical deterioration, they exhibit high permeation rates. Concurrently, it is emphasized that further investigations are imperative. Lo Basso et al. [14] also assert that the transportation of hydrogen in smaller volumetric quantities is feasible without significantly compromising the safety of the pipeline.

As a result, new regulations and standardized codes need to be drawn up. Islam et al. [36] also mentioned that with lower pressure levels as at the distribution systems, the effects on materials will be much smaller.

Moreover, the pressure drop increases with the length of the pipeline. Thawani et al. [63] investigated the pressure losses and thus the mixing velocities of methane with hydrogen for different pipe diameters of the materials Medium Density Polyethylene (MDPE) and X52 steel pipes over a length of 100 m. It was found that when hydrogen flows at the same speed as methane, the pressure loss is much lower due to the significantly lower operating pressure. However, as this means that less power can be delivered, the speed must be increased, which leads to an increase in the volume flow. To compensate for the higher-pressure loss, plastic materials could be used (lower roughness of the pipe).

Most analyses were found for transport lines. Overall, Fig. 6 shows the problem as a flow chart. For medium-sized power plants, the effect can be much smaller, as the lengths of the pipeline are shorter, as is the diameter. For this reason, the volume flows $\dot{V}_F$ and velocities v were calculated using Eqs.(6) and (7) from the calculated mass flows $\dot{m}_F$ of

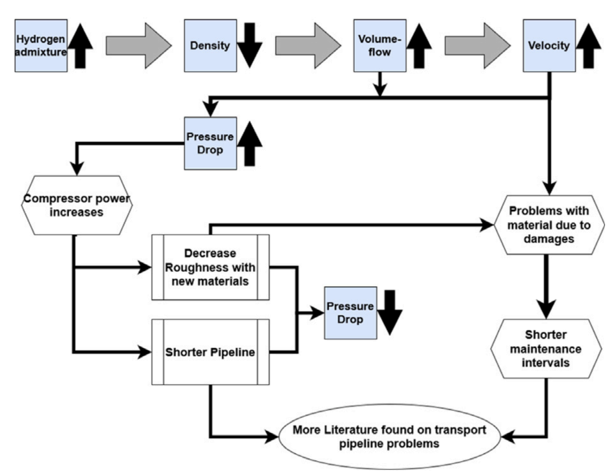

Fig. 6. Flowchart of the behavior and problems of Hydrogen blending in pipelines to deliver same power as natural gas (own work).

the Brayton Cycle and with the fuel density ρ_F and the cross sectional area A of the pipe:

$$\dot{V}_F = \frac{\dot{m}_{Fuel}}{\rho_{Fuel}} \quad (6)$$

$$v = \frac{\dot{V}_{Fuel}}{A_{pipe}} \quad (7)$$

The calculation of the total volume flow and velocity was calculated according to the structure of the power plant (see Section 2.3). The pressure levels of 24 bar at 15 °C (after the pressure control valve) and 34 bar at 10 °C (coming from distribution pipeline) were used for this. As there is no precise knowledge of the pipe diameters within North CHP-CCGT plant of Bonn, DN400 and DN200 were chosen to represent the velocities. Based on the Darcy-Weißbach equation (see Eq.: (8)) with a constant pipe friction λ of 0.0318 the pressure losses

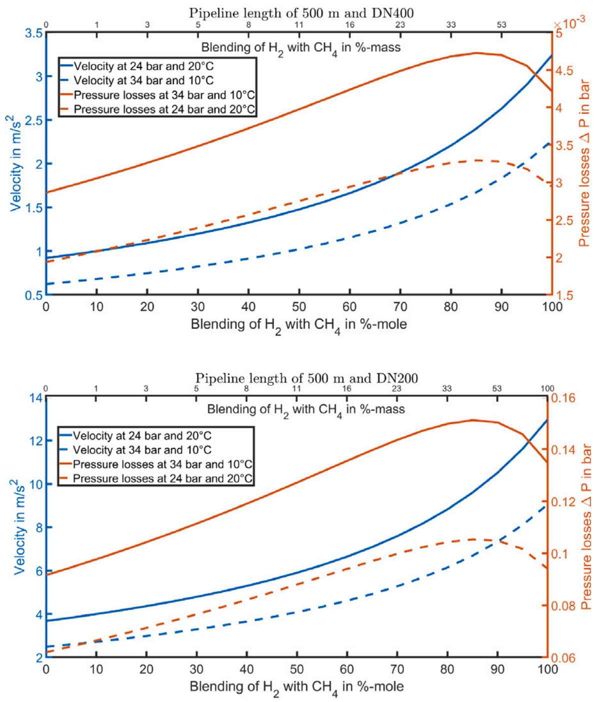

Fig. 7. Calculated pressure losses within different levels in the power plants for two pipe diameters DN400 and DN200 (own work).

were calculated.

$$\Delta p = \lambda \cdot \frac{L_{pipe}}{D_{pipe}} \cdot \frac{\rho_{Fuel}}{2} \cdot \left(\frac{\dot{V}_{Fuel}}{A_{pipe}}\right)^2 \tag{8}$$

Fig. 7 shows the results.

It can be seen that velocity increases with increasing hydrogen content, leading to greater pressure loss. However, there are different values for halving the diameter. With half of the diameter, the velocity becomes around 4 times higher. The pressure loss for DN400 is very low at approx. 0.004 bar and 0.003 bar with 100% hydrogen. In contrast, the pressure loss for DN200 can have a slightly greater influence at 0.135 bar and 0.095 bar. It is therefore important to know how large the supply lines are. In order to gain further insights, an additive pipe friction can be selected, whereby windings and fouling are better represented. The pressure losses at the different absolute pressures of 24 and 34 bar show only minor differences.

It can be observed that pressure loss is of lesser significance at power plant level. Of greater relevance are the markedly elevated velocities, which have the potential to result in heightened absolute pressures. This phenomenon was examined in Wang et al. [37]. They developed a mathematical model for simulating both stationary and transient states of hydrogen/natural gas mixtures. Rather than focusing on the pressure drop, the model was designed to investigate the increased quantities in the pipe. The results demonstrate that the pressure in the pipeline exceeds 30 bar at hydrogen proportions of over 30%, which could potentially lead to further complications. Freitag et al. [33] highlight that an increase in the cross-sectional flow area by 30% results in a diameter growth of the piping system by approximately 14%. This leads to higher costs of the retrofit.

Our own analyses and the two research papers show that the velocities or volume flows would be the clearly limiting factor. As can be seen in Fig. 7, a larger diameter could lead to a reduction in the velocities and thus the pressures could be within the material limits again.

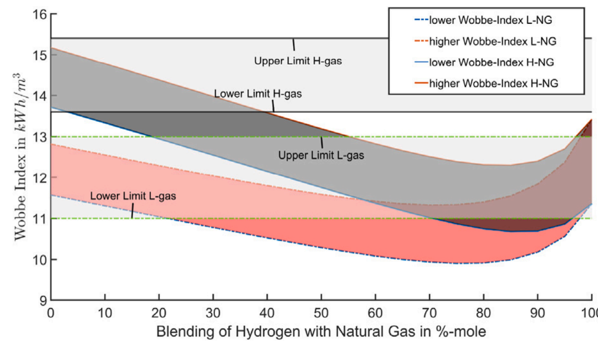

Fig. 8. Wobbe Index with H-Gas and L-Gas with different blending steps (own work).

Wobbe-index. The Wobbe-index described in Section 2.5 was calculated for L-gas and H-gas as a function of the hydrogen blends. In addition, the currently prescribed limit values for L-gas and H-gas were used (see Table 4). The composition of L-gas and H-gas follow the proportions in Table 1. The results are shown in Fig. 8. It can be seen that the entire band (from the upper H-gas limit to the lower L-gas limit) is utilized. When hydrogen is added to L-gas, the lower Wobbe-limit is undercut to a greater extent. This makes the transition to 100% hydrogen more problematic because you are outside the previous limits. With 100% hydrogen, you are within the current limits. However, the code of practice G 260 (A) defines the quality requirements for fuel gases in the public supply, forming a framework for transportation, trade, technical applications and storage in Germany. The 2021 revision includes specific regulations for hydrogen, which may be introduced into natural gas networks at a maximum of 10%. However, a differentiated approach is to be taken with regard to industrial applications. Gas turbines that have not been modified are limited to 1%, while minor modifications to gas turbines may accommodate up to 5% hydrogen. Finally, up to 100% hydrogen may be used in modern or adapted systems. Additionally, a hydrogen-only group has been introduced, comprising the 5th gas family and designed for the use of pure hydrogen [64].

Until the ramp-up of 100% hydrogen, parallel hydrogen supply lines must be built for some power plants, as rededication at regional level is only considered late or never. Therefore, depending on the origin of the hydrogen, a separate blending station must be available within the power plant. This must be adapted to the capacity of the gas turbine for hydrogen blending.

4.2. Gas turbine

There are two different aspects to consider for the gas turbine. Firstly, stable combustion, as described in Section 2.5, and secondly, the formation of NOx and CO. Combustion behavior is a major factor in the formation of NOx. Therefore, a description is given of how NOx is formed, how it occurs in modern natural gas turbines and the problems associated with the use of hydrogen in gas turbines. The challenges associated with hydrogen combustion are then described in more detail and the current research status of gas turbines for hydrogen blends is explained.

The aim is to achieve low emissions, which mainly consist of CO_2, NOx and CO. CO2 can only be minimized by becoming more efficient at burning or different fuels. NOx include all nitrogen oxides produced during combustion. In particular, nitrogen monoxide (NO) and nitrogen dioxide (NO_2) are considered, whereby the proportion of NO is significantly higher than that of NO_2. This is because NO is produced at high temperatures, whereas NO_2 is produced at lower temperatures. NOx is particularly harmful to the environment. However, as NO can be converted to NO2 in a shorter period of time through oxidation in the air, both are considered in the Emissions Act [65]. NOx is formed at high combustion temperatures, while CO is formed at low temperatures, so we need to find the optimum band where we have low emissions but higher efficiencies [45,66].

In principle, higher temperatures would lead to an increase in the efficiency of the turbine, but as the Emission Control Act must be complied with, the parameters of the entire power plant are designed in such a way that compliance is guaranteed.

In order to still achieve good efficiencies, dry low emission (DLE) or dry low NOx (DLN) systems have been developed in the natural gas sector and have become common in modern turbines. They operate according to the principle of lean premix combustion (as does the SGT750 turbine at the North CHP-CCGT plant in Bonn). This method works on the principle of over-stoichiometric combustion, which reduces the combustion temperature and thus the NOx emissions. To avoid local stoichiometric combustion and thus locally high temperatures, sufficient mixing of the mixture is required before it reaches the flame zone. Very good mixing is therefore particularly important. Now that a combustible mixture is present before reaching the combustion chamber, the system must closely monitor the gas properties to avoid premature ignition [67]. An overview of the changed combustion parameters with different blending stages of hydrogen to natural gas can be found in [68].

As described in Section 2.5, the use of hydrogen increases the risk of flashbacks. This would become a danger with conventional DLE turbine due to the premixing zone. In addition, the flame temperature rises significantly and there is uneven combustion, which leads to increased NOx formation. Poorly adapted DLE turbines can therefore only operate up to a certain level of hydrogen blending. This requires parts of the burner to be replaced and/or the operating parameters to be adapted. New technologies must be developed for higher hydrogen blends [69]. The ETN Hydrogen Gas Turbines Report shows the current status of gas turbines with hydrogen blends in a simplified form and describes that we are currently around 45% of H_2 by volume [70]. Clean Hydrogen Europe has also provided an overview of the key performance indicators. As of early 2024, the current research status appears to indicate blends of 40% hydrogen by volume [71] . Many different methods and new approaches for hydrogen blends in gas turbines are being explored in research. Therefore, reference is made to additional literature that examines specific technologies, as a detailed discussion of these is beyond the scope of this paper. For example, a review of gas turbine combustion technologies for hydrogen blending was conducted by Cecere et al. [13] and showed that there are some interesting approaches that can enable high blending. A white paper by the National Energy Technology Laboratory (NETL) from 2022 [72] also examines various turbines currently on the market. It shows that Siemens, for example, claims 100% capability, but they uses diffusion combustion, which produces significantly higher NOx emissions. Therefore this turbine is not marketable. At the same time, it is mentioned that turbines with 100% hydrogen and low NOx will be developed in the next 20 years through intensive research.

The Siemens white paper [73] on hydrogen power and heat with Siemens gas turbines shows the current hydrogen blends of various turbines. The paper shows that current DLE burners from Siemens can, in some cases, handle up to 40% Hydrogen by volume.

Kawasaki is working together with Aachen University of Applied Sciences and B&B-AGEMA on the development of micromix technology [69]. This approach involves modifying the burner so that multiple small flames are ignited instead of a single large flame. These small flames can accommodate larger temperature ranges, as the smaller flame front minimizes NOx. This has been successfully tested in initial trials. The publication by Funke et al. [74] also analyzed a micromix DLE system. Within the range of operational conditions that were the subject of investigation, the combustion chamber exhibited low NOx emissions in the context of full-scale gas turbine conditions.

Besides the different combustion behavior of hydrogen, there are also operational challenges in the power plant. Current gas turbines operate with the option of using oil as fuel if the natural gas supply fails. Furthermore, which aspects will change for future (100% H2) gas turbines or whether an older gas turbine will remain at the power plant site still needs to be investigated and will be different for each power plant. In addition, future gas turbines that supply DH networks will not always run at full load, as most of the summer load can be managed by the heat pumps. This partial load operation can lead to problems with the steam turbine, as the corresponding nominal temperatures of the steam are not reached, or excessive amounts of steam may be generated. With the bypass, this excess steam is discharged directly into the condenser. The bypass is connected downstream of the gas turbine [31].

Table 7
Calculated dew point temperatures for different proportions of water vapor at an assumed pressure of 30 bar. Dew points from [76]. Water vapor content from own calculations based on Brayton Cycle.

Case	x_{H_2O}	p_{H_2O}	Dew point
Methane	6.1%	1.83 bar	119 °C
Hydrogen	10%	3.00 bar	133 °C

4.3. Heat recovery steam generator

In order to determine the influence on HRSG, a precise analysis of the gas turbine exhaust gases, considering the blends and combustion temperatures, would be required. However, this is beyond the scope of our study.

With increased hydrogen share in the combustion, the water content in the exhaust gas also increases. This increases the dew point of the exhaust gas and leads to increased corrosion of the HRSG, particularly at its outlet. In addition, the exhaust gas volume flow increases, which could influence the heat exchangers and maintenance intervals [75]. The water content of pure methane and pure hydrogen can be calculated as a simplified estimate. This is based on the assumption of stoichiometric combustion with pure oxygen. The water content increases by a factor of around 13 with pure hydrogen combustion under stoichiometric conditions. However, with lean combustion, the amounts of water in the exhaust gas will differ.

With the Brayton model described in appendix, the massflows of the exhaust gas were calculated. The exhaust gas consists of H_2O, excess O_2, CO_2 and unused nitrogen from air. NOx were not calculated. The results are shown in Fig. 9.

The sum of all gas components is shown on the top graph in Fig. 9. As the hydrogen content increases, the total mass flow decreases from 115 kg/s to 114 kg/s. This is due to the fact that with less methane, there is less CO_2 in the exhaust gas. The excess O_2 increases with higher hydrogen content because less oxygen is needed for the reaction (see Eq. (1) and (2)). At the same time, the water content in the flue gas increases from 4.4 kg/s to 7.3 kg/s. The increase is smaller than originally assumed but could still impact downstream systems due to the different heat capacities of the flue gas and changes in the dew point. Assuming a pressure of approximately 30 bar in the HRSG system and utilizing the calculated temperatures after the turbine, the dew point can be estimated through the calculated proportions of the exhaust gas, as illustrated in Table 7. This estimation is based on the partial pressures of water, calculated using the mole fractions of water vapor present in the exhaust gas. The dew point can be calculated using one IAPWS-IF97 online calculator [76]. It is evident from the results that the dew point increases significantly, which will lead to necessary changes in the downstream system.

The influence of hydrogen blends for gas turbines and the final HRSG cycle with a steam turbine were analyzed for a power plant in Jeong et al. [21]. They examined the HRSG using the e-NTU method. If the turbine inlet temperature is kept constant, an increase in the hydrogen content would lead to an increase in the heat capacity ratio,

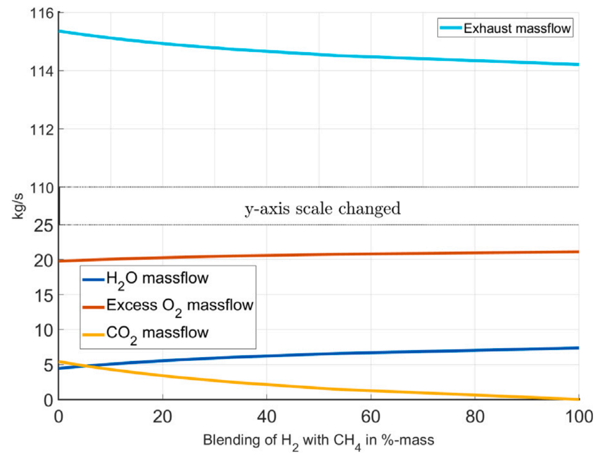

Fig. 9. Calculated exhaust gas composition based on the Brayton Cycle with different admixtures of hydrogen (own work).

while at the same time the mass flow would decrease. The higher the turbine inlet temperature, the lower the exhaust gas temperature and mass flow, and thus the output of the steam turbine. At the same time, the electrical output of the entire plant would increase, compensated for by the gas turbine. In the case of a combined heat and power plant to feed the district heating network, this is a disadvantage. Therefore, with the same DH output, additional firing must be provided by auxiliary boilers. The auxiliary firing would follow the principle of a burner. The Wobbe-index and the real densities play a role here. As described in the beginning, this would have to be adapted accordingly.

4.4. Flue gas aftertreatment

The flue gas system essentially consists of three groups: NOx, fly ashes and sulfur dioxides. Each group is minimized or filtered before exhaustion. As the last two components are produced during the combustion of carbon, the NOx remains at 100% hydrogen use. At up to 100% hydrogen, all three components should remain. Depending on the Emission Standards Law, the rear components, which are only relevant with natural gas combustion, could disappear even at lower blending levels as they could already be below the limits after combustion. At the same time, the denitrification process (also known as the secondary system) might have to undergo major changes, particularly in the ammonia storage system.

The extent to which the power plant needs to be adapted depends heavily on the gas turbine technology used. If the NOx are reduced in this primary system, the impact on the system could be minimal. If the gas turbine is not well adapted to the use of hydrogen, significantly higher levels of NOx are produced. The secondary system would then have to be adapted accordingly and, if ammonia is used, the storage facility would have to be significantly increased [65]. This results in a notable rise in expenses and an additional problem in terms of available space, as the selective catalytic reduction process (SCR) reaction occurs within a confined area [33]. The extent to which an increased volume flow of exhaust gases leads to changes in the secondary system still needs to be investigated.

Due to the increased water content of the exhaust gases, the dew point temperature drops (see Table 7). In the SCR, which works with ammonia injection, this can lead to the unwanted formation of ammonium chloride, ammonium hydrogen sulfate, ammonium sulfate and alums. As the process runs at a certain temperature, a reduction in exhaust gas temperatures could also lead to adjustments to the SCR process [65].

4.5. Operation

For the cold and hot starts of the gas turbine, a fluctuation in the mixing proportion of hydrogen can be problematic, as the combustion properties also change and can then be outside the valid range [56]. With the help of a blending station and a hydrogen storage tank, these fluctuations could be controlled during the start-up phase. When hydrogen mixtures are supplied directly from a pipeline, the Wobbe-index is the most important control variable. This is currently the case for natural gas supply, where fluctuating natural gas mixtures are supplied.

For certain limits of hydrogen blending, e.g. above 30% by volume for metering devices, further investigation is required to determine how well the devices cope with fluctuations in their limit range. An accumulation of unburned hydrogen in the exhaust gas at the end of the HRSG could also lead to safety problems. However, these are not expected during operation as the combustion is lean. Nevertheless, when the gas turbine is shut down, there may be increased accumulations of hydrogen in the HRSG. To minimize any hazards, purging of the HRSG could be performed shortly before start-up [31]. Based on the local requirements explosion safety should be installed and need to be changed before the operation.

For a heat-led system, the amount of vapor is crucial for ongoing operation. Changes in the hydrogen blend during operation could lead to changes in the volume flows for the HRSG. The fluctuation range in which this could lead to problems with the provision of heat supply, still needs to be investigated.

5. Discussion

According to the Gas 2050 roadmap [58], approx. 20% hydrogen by volume for households and small CHP plants is possible with little effort. The DVGW regulations currently permit 10 vol.-% of hydrogen in the pipeline. However, for industrial consumers, due to the similar Wobbe-index and relative density, individual quantities can be defined for each consumer independently of the regulations. This has an influence, for example, on the burners of the auxiliary boilers in a power station. For measuring devices, 30 vol.-% is also possible in some cases.

In the first position papers for 2023, stages of 10% [59] and 17% [32] are mentioned for gas turbines and 25% [59] and 51% [32] for the second stage. This indicates a wider range of blending steps.

As most research is focused on the transmission lines, it is increasingly necessary to extrapolate the results to the distribution networks or the power plant side. In distribution networks or the power plant side, different pipe diameters, pressures, and pipe lengths are present. Therefore some effects at the power plant level can be neglected. The pipe materials are generally suitable for hydrogen embrittlement with increased hydrogen content. The permissible limiting velocities also appear to be similar to those for natural gas, although there may be longer service and maintenance intervals.

To estimate the influence of the pressure drop and the JT effect, approximate calculations of the velocities and JT coefficients at constant load were carried out in this work on the basis of the gas properties from GERG-2008 EoS and a gas turbine model based on the Brayton Cycle. This showed that the velocities increase overall leading to higher pressure losses. In order to calculate the pressure drop over a distance of 500 m, the Darcy-Weißbach equation is utilized. A constant value was assigned to account for pipe friction. The value thus remains constant regardless of the length of the pipe and is applicable only to a straight section. This could be adjusted slightly, for instance, by incorporating an additive pipe friction. As a result, the pressure loss at the end of the pipe is so minimal that its impact on the change in temperature and the overall pipe length is also negligible. Nevertheless, more precise pipe models could prove beneficial, as the temperature and the absolute pressure exert a considerable influence on pipe stability, necessitating a corresponding alteration in the pipe diameter.

For the JT effect, it was shown that with a pressure reduction of 8 bar, the gas becomes only slightly warmer with hydrogen, but the cooling is missing with the previous natural gas. At the same time the heat capacity of hydrogen is much higher than that of natural gas leading to a bigger dimension of the preheater. In order to analyze a more precise influence, a more detailed pipe model should be build up and coupled with a pressure regulator.

The power plant will initially be supplied with hydrogen via its own hydrogen pipeline. For this reason, constructing corresponding blending stations at the power plant will be necessary. In addition, the space requirements and the question of whether a separate hydrogen storage facility could be useful for equalizing possible fluctuations in the hydrogen content should be investigated in more detail.

With gas turbines, 40 vol.-% hydrogen is possible with small to medium adjustments. The main challenge lies in complying with the nitrogen oxide limits, as the flame temperature rises significantly with higher hydrogen proportions. Gas turbines are being strongly promoted in R&D so that the goal of 100% hydrogen suitability by 2030 appears realistic.

The flue gas composition and the influence on the downstream systems are rarely considered in research. However, the changed flue gas composition with increased hydrogen content can lead to condensation in the HRSG and thus influence the steam turbine and the district heating output. An approximate calculation of the water content in the exhaust gas leads to a smaller increase, but should not be neglected. With more water, the dew point temperature of the exhaust gas increases, which can lead to severe corrosion in the HRSG and the HRSG operates outside its nominal range.

The nominal temperature of the denitrification can also change as a result. Therefore, a gas turbine model must be built that allows a more detailed exhaust gas calculation. Since R&D aims to maintain combustion temperatures at the same level as current natural gas turbines to minimize nitrogen oxides, existing turbines can serve as a basis for calculations with hydrogen blending. In addition, further investigation is needed as to whether additional firing is necessary to compensate for changes in the heat output, e.g. due to changes in the HRSG or the steam turbine. Additional firing in particular could be useful, as the firing can be adjusted more easily according to the Wobbe-index.

Although the approximate calculations in this work were helpful for an initial estimate of the effects on the CHP-CCGT unit, the influences of components on each other and the partial load behavior were neglected. Appropriate models should therefore be developed to allow partial load behavior and enable the coupling of individual components. Overall, current hydrogen shares of 15 vol.-% to 30 vol.-% appear to be feasible. However, these influences must be analyzed in detail for each power plant. In addition, the possible hydrogen share without a dedicated electrolyzer is fundamentally dependent on legislation and the possible hydrogen distribution networks through to individual power plants. As there are already major research projects looking at hydrogen production and transport infrastructures such as the German hydrogen flagship project TransHyDE, it can be assumed, that an suitable infrastructure will be exist.

However, there are additional challenges associated with using hydrogen. These include the increased risk of exposure due to hydrogen slips and leakage. Increased safety precautions may be required due to different ignition limits of hydrogen compared to natural gas [77]. In addition, the impact on the environment is not yet well understood. Tromp et al. [78] describe that this needs to be further investigated.

If any of the stated limit states is exceeded, especially for large components like the gas turbine, the plant's operation must be interrupted. Power plant operators are already familiar with this process, as it is typically carried out during the summer months when heat demand is at its lowest in a heat-led power plant.

6. Conclusion

The aim of this work is to provide an overview of the retrofit areas of a CHP-CCGT plant with district heating usage and to identify possible problems. For this purpose, the North CHP-CCGT plant was as an example to enable a more detailed analysis of the individual areas. The set-up and various investigations made it possible to identify four major areas that could be influenced by the addition of hydrogen: The fuel gas system (supply from the pipeline to the gas turbine), the gas turbine, the heat recovery steam generator and the exhaust gas aftertreatment. The fuel gas system could be derived from the investigations of the transmission network. It was found that hydrogen embrittlement does not pose a huge risk in the pipelines at the power plant level. The pressure drop also appears to be less relevant in power plants but needs to be investigated further, including change in the diameter of the pipeline, velocity limits and material damages due to higher flows. According to the investigations, the gas appliances themselves appear to cope with higher hydrogen blends. Currently (based on the Code of Practice G-260 (A)), blends of 10 vol.-% are officially permitted in Germany in pipelines. For each consumer different values are permitted. Within the fuel gas system, the calculated pressure losses are very low. Higher volume flows still can lead to a change of diameter of the pipes. At the same time the preheater has to be sized bigger to achieve the same gas temperature, due to the higher heat capacity of hydrogen.

The development of gas turbines is highly advanced, and today's gas turbines can accommodate adjustments of up to 40 vol.%. Achieving up to 100 vol.% appears feasible. The biggest challenge is the formation of nitrogen oxides or changes in exhaust gas composition

There are only a few studies on the influence of retrofitting the HRSG. A simplified calculation has shown that the exhaust gas has less water content than first assumed but still leads to an increase in the dew point. However, combined with changes in volume flow and flue gas temperatures, this can still result in performance losses in district heating generation. The flue gas aftertreatment is also affected by the increased water vapor content and must be readjusted accordingly.

In many cases, the retrofit steps are constrained by the gas turbines. Possible efficiency losses in the HRSG and steam turbine can be compensated for by efficiency increases in the gas turbine due to higher combustion temperatures. This approach makes sense for electricity-led plants. For heat-led plants, such as the Bonn North CHP-CCGT plant, this leads to a drop in district heating output. For this reason, the output of the HRSG must be considered as a limiting factor for heat-led plants and the change in flue gas must therefore be analyzed. The extent to which a reduction in heat output through modifications to the HRSG, new steam generators or additional firing makes sense must be investigated further. Additional firing in particular could be useful, as the firing can be adjusted more easily according to the Wobbe-index.

For future work, specific models based on the CHP-CCGT must be developed and integrated. This will enable a more detailed analysis of their interactions and influence. In particular, the flue gas calculation and the downstream district heating generation must be modeled.

CRediT authorship contribution statement

Barbara Schiffer: Writing – original draft, Visualization, Software, Methodology, Formal analysis, Conceptualization. **Malte Pfennig:** Software, Formal analysis. **Tanja Clees:** Writing – original draft, Supervision, Methodology.

Declaration of Generative AI and AI-assisted technologies in the writing process

During the preparation of this work the author(s) used GrammarlyGo and DeepL Write in order to make the text more readable and identify any gaps. After using this tool/service, the author(s) reviewed and edited the content as needed and take(s) full responsibility for the content of the publication.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary data

Supplementary material related to this article can be found online at https://doi.org/10.1016/j.ijhydene.2025.02.160.

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