Hydrogen in natural gas: how does it affect industrial end users?

HYDROGEN IN NATURAL GAS: HOW DOES IT IMPACT INDUSTRIAL END USERS?

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Abstract:
All over the world, power-to-gas (PtG) is being discussed as a promising way to economically store large amounts of surplus energy from wind or solar power generation in times of low demand. In this manner, the existing gas grids could serve as large-scale energy storage devices and become a key component of a future integrated energy infrastructure. One important question in the context of power-to-gas is whether it is actually necessary to convert hydrogen produced by electrolysis to methane or if it is possible to directly feed in hydrogen into the gas grid.
The latter offers significant financial benefits as methanation requires additional investments, the local availability of CO_2 and incurs an efficiency penalty. However, end users, especially those with sensitive applications in thermal processing industries or power generation, would generally prefer that no hydrogen is introduced into the gas grids. They fear negative consequences for their processes and applications in terms of product quality, process efficiency or pollutant emissions (e. g. nitrogen oxides, NO_X). As the share of gas consumption from the non-residential sectors is likely to grow in the coming years and already amounts to more than 50 % in both the EU and the US, these concerns have to be taken into account when discussing any large-scale deployment of power-to-gas.
GWI investigated the impact of higher concentrations of hydrogen in natural gas on industrial end-use applications in a publicly-funded German research project. Using both computer simulations and experiments of three "off-the-shelf" industrial burner systems in a semi-industrial test rig, the effects of H_2 contents of up to 50 vol.-% on efficiency, heat transfer and pollutant emissions were analyzed in detail. It was found that indeed hydrogen can have a profound influence on furnace performance in terms of heat transfer, efficiency, flame shape and NO_X emissions but also, that these effects can be mitigated by advanced measurement and control technologies. Both the simulation and experimental results indicate that if detailed information about the currently available gas quality, or even better, composition is used to adjust the burner settings, the impact of hydrogen on the combustion process can be minimized. Even H_2 admixtures of 50 vol.-% (way beyond of what is currently being discussed) did not lead to a significant increase of NO_X emissions or loss of efficiency, neither in the simulations nor in the experiments, when burner settings such as firing rate and air excess ratio were properly adjusted, based on fed-forward information about gas quality.
This research is only a first step into the investigation of the impact of hydrogen on large-scale combustion systems. Other applications, e. g. gas turbine combustion chambers and gas engines in the power generation sector, but also processes in the chemical industries which use natural gas as a feedstock, will most certainly respond differently to the presence of hydrogen in natural gas. In manufacturing processes, there is also the question of how the manufactured product may be affected by hydrogen.
Nevertheless, the findings presented in this paper indicate that the effects of hydrogen on an industrial large-scale combustion process can be managed with appropriate measurement and control technology.

Keywords:
industrial combustion, power-to-gas, natural gas, hydrogen, renewable energies

Introduction

Global warming due to the emission of so-called greenhouse gases (GHG) such as carbon dioxide (CO_2) is considered to be one of the central challenges of the 21st century. At the same time, the worldwide demand for electricity increases due to the growing world population and improving living conditions in many parts of the world. In the industrialized countries, there is a discussion going on how to prepare economies and existing energy infrastructures for a low-carbon future, i. e. without heavily relying on carbonaceous fuels such as coal, mineral oil or natural gas for transport, power generation, residential heating and industrial manufacturing.

In Europe, much of this discussion centers on the generation and transmission of electricity, often with distinct national flavors. In Germany for example, the “Energiewende” aims to compensate the phasing out of nuclear power generation with a corresponding increase in power generation from renewable sources such as wind and solar power. Even in traditionally pro-nuclear nations such as France, it is acknowledged that there is a need to integrate renewable and sustainable energy sources into the energy infrastructures to greater extent than in the past as part of the “transition énergétique” [1], [2].
One challenge in this context is that by their very nature, energy sources such as wind and solar power are dependent on local meteorological conditions such as day and night, cloud coverage or wind speeds. Electrical energy on the other hand, cannot be easily and economically stored in large amounts; instead, electrical grids have to balance supply and demand almost continuously and their storage capacity is generally rather limited. Thus, one technological challenge is how to deal with surplus electricity in times of high supply, and at the same time be able to provide sufficient electricity in times of high demand for all end-users.
Also, the balances of supply and demand on a local level are likely to shift dramatically if renewable energy sources are integrated into the electricity grid in great numbers: in Germany for example, wind turbines are primarily being erected in the northern parts of Germany due to the better meteorological conditions there. But the energy consumers, i. e. the main population and industrial centers, are located in the west or the south for the most part. This means that large amounts of electricity will have to be transmitted along the entire length of the country. The existing power grid infrastructure is not equipped to handle this.
A promising solution to these problems is the so-called “power-to-gas” approach [3], [4]. In times of high electricity production from renewable sources, surplus electricity is used in an electrolyzer to produce hydrogen from water. This hydrogen can either be stored and used locally on demand to provide electricity in fuel cells or gas engines, or it could be fed, directly or after an additional methanation step to convert hydrogen into methane, into the natural gas grids. The advantage of this approach is that it is relatively easy to store large quantities of gas. In total, the German natural gas grid for example has a storage capacity of about 220 TWh [5] compared to a storage capacity of about 0.4 TWh in the German power grid. Thus, “power-to-gas” could help relieve electricity grids and reduce the necessary, yet often unpopular expansions of existing electricity infrastructures.

Hydrogen in natural gas

From a purely energetic point of view, it is better to inject the hydrogen directly into the gas grid instead of using a subsequent methanation process since the methanation step incurs an efficiency loss and requires additional investments. Also, CO_2 has to be procured in sufficient quantities.
On the other hand, there are millions of appliances and large-scale industrial and power generation processes connected to the gas grid today. It has to be ensured that these end-use applications do not suffer negative consequences in terms of safety, efficiency or pollutant emissions if they are confronted with hydrogen admixed to natural gas. The same is obviously true for the gas infrastructure itself where some investigations have already been carried out, such as [6], [7]. The opinions about benefits and risks of hydrogen injection into the gas grids differ: some see much promise and only little risk for end-users or infrastructure in this approach [8], [9], [10] while others are more skeptical and point out potential drawbacks [11], [12].
In Germany, the Codes of Practice G 260 [13] and G 262 [14], issued by DVGW (the German Technical and Scientific Association for Gas and Water), specify the quality of natural gas distributed in German public gas grids. These documents recommend that the hydrogen content of natural gas be at less than 10 vol.-%, as long as the other gas quality criteria (relative density, gross calorific values and superior Wobbe Indices) comply with the limits given in G 260. They also acknowledge, however, that there are sensitive applications for which lower hydrogen contents may be required, for example gas turbines or gas tanks for vehicles [15], but also process gas chromatographs which may not be able to measure H_2, leading to billing problems. Additionally, there is concern that porous underground gas storages could be affected by higher hydrogen concentrations.
One point of particular concern is the industrial end-use sector since industrial gas utilization is characterized by a very high degree of diversity and optimization, making it difficult to draw generalized conclusions. Industrial furnaces and their components have to operate with very high

requirements for efficiency, product quality and pollutant emissions [16]. In the chemical industry, natural gas not only serves as a fuel to provide process heat, but also as a feedstock, e.g. in the production of fertilizer. There is significant skepticism among these end-users with regards to the injection of hydrogen into the natural gas grids as they fear that this might have a negative impact on already very sensitive processes [12]. Similar concerns have also been raised in the field of power generation equipment [17], [18]. As these two sectors account for more than half of the German natural gas consumption [19], these issues have to be taken seriously.
In order to investigate the effects of hydrogen injection on industrial combustion systems, a publicly funded research project called "H_2-Substitution" was launched in Germany (carried out by GWI) to investigate the sensitivity of industrial combustion processes with regards to hydrogen in terms of efficiency, heat transfer, pollutant emissions and combustion stability. By means of simulations and experimental investigations of different burner systems on a semi-industrial scale as well as simulations of real-life processes and furnaces, the effects of hydrogen admixture into natural gas were to be examined in detail.

Impact of hydrogen admixture on industrial combustion processes
The objective of the research project "H_2-Substitution" (AiF Grant No. IGF 18518 N/1) was to analyze how common industrial burners and combustion processes react to higher and fluctuating contents of hydrogen in the natural gas. Both experimental methods on a semi-industrial scale and CFD simulations (CFD: computational fluid dynamics) were used as part of the project. For the experiments, various amounts of hydrogen were admixed to the natural gas available at the premises of Gas- und Wärme-Institut Essen e. V. (GWI), a North Sea H-Gas, in various increments (0 %, 2.5 %, 5 %, 7.5 %, 10 %, 15 %, 20 %, 30 % and 50 % of H_2 in the mixture, all values given as vol.-%). These test gases exceed the limits imposed by DVGW G 260 in many cases (the maximum permissible hydrogen content for a North Sea gas is at about 12 vol.-% H_2), but higher hydrogen contents were investigated as well, both to emphasize the physical effects of hydrogen on a combustion process originally designed for "pure" natural gas, and also to provide information for possible future extensions of the gas quality limits in order to accommodate a larger presence of power-to-gas plants in the gas infrastructure. These test gases were also used for the accompanying CFD simulations.

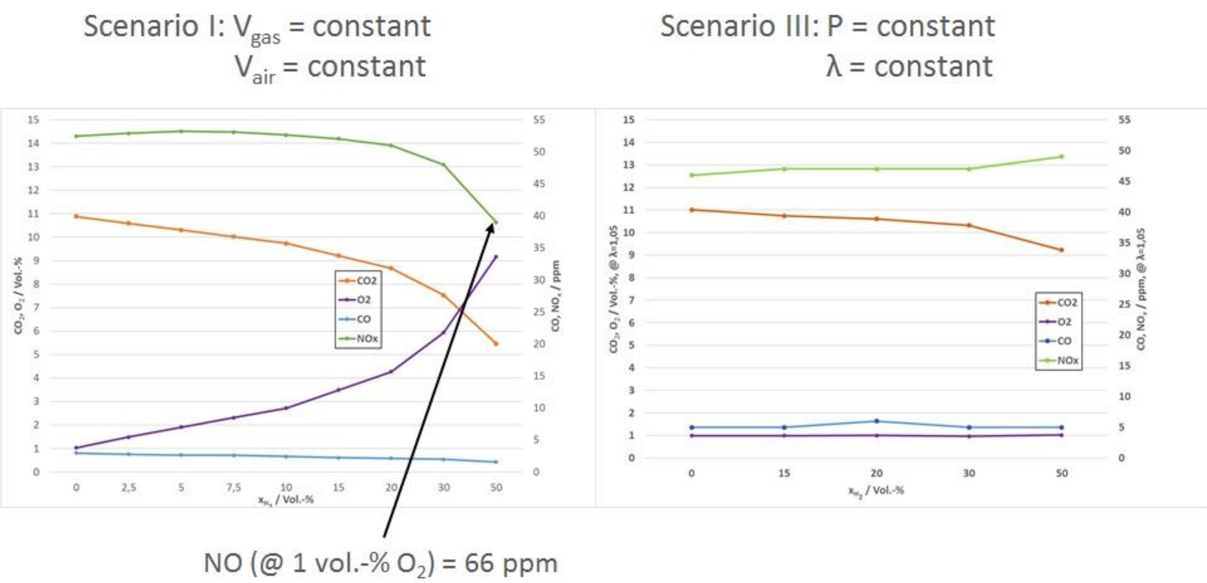


Figure 1: Main exhaust gas species as a function of the hydrogen admixture ratio for different scenarios for Burner 1

For the experiments, the test gases were used in three different burner systems (Burner I: a modular non-premixed jet burner; Burner II: a forced-draught burner; Burner III: a flameless oxidation burner) which were installed at one of GWI's semi-industrial burner test rigs. The firing rates for all burners were in the 100 kW range, air excess ratios were set to be at 1.05, unless stated otherwise. Such a low air excess ratio may be extreme by the standards of residential gas appliances, but is actually very common in industrial gas utilization for reasons of efficiency and pollutant emissions, particularly of nitrogen oxides [20]. No air preheating was used for these experiments. **Figure 1** shows some measurement results for Burner 1, a common non-premixed process burner, for two different scenarios. In Scenario I (seen in the diagram on the left hand side), it is assumed that the hydrogen content increases but there is no local gas quality measurement equipment in place to detect the change. This is more realistic than it might seem on first glance: it was found in a recent statistical survey [20], [21] that the vast majority of industrial furnace operators in Germany do not have access to up-to-date gas quality data. They usually rely on monthly information provided by their local gas grid operator for billing purposes. Thus, this is a surprisingly common scenario.

As there is no way to detect the H_2 content in the fuel gas, the volume flows of both fuel and oxidizer are assumed to remain constant in this scenario, which means that the overall air excess ratio of the combustion processes increases due to the reduced minimum air requirement of a natural gas / hydrogen blend when compared to “pure” natural gas. At the same time, the calorific value of the fuel gas also decreases with rising hydrogen admixture rates which means that the energy input into the furnace decreases as well in this scenario.

In terms of NO_X emissions, this means that the measured NO concentrations (NO_2 is negligible in this context) in the flue gas are reduced since they are somewhat diluted due to the higher air excess ratio. If these NO_X emissions are, however, corrected to a fixed O_2 content in the flue gas to better compare results (this is also required practice to check compliance with legal emission limits), it can be seen that they actually increase from about 50 ppm to 66 ppm at an O_2 content of 1 vol.-% in the flue gas in the case with 50 vol.-% hydrogen in the fuel. This actual rise of NO formation is caused by two factors. Local combustion temperatures in the stoichiometric reaction zone increase due to the presence of H_2, while at the same time, the system works with a higher air excess ratio which in this near-stoichiometric case also results in some increase of NO formation due to the higher local availability of oxygen.

On the right hand side of Figure 1, measurements for the same burner can be seen, but in a different scenario. In Scenario III, it was assumed that some kind of gas quality measurement device was used in combination with advanced burner control systems to keep both the firing rate and the air excess ratio of the burner constant. The measurement for this best-case scenario indicate that there is still some increase in NO formation, but less than in Scenario I since in this scenario, air excess ratios are constant.

Similar measurements were also carried out for Burner 3, a flameless oxidation burner. Flameless oxidation is a very popular combustion technology for many applications in metals industries (cf. **Figure 2**) since it provides a very homogeneous temperature distribution in combination with a very stable combustion and very low NO_X emissions [22]. For this burner, measured NO emissions rise dramatically in Scenario I, despite significantly higher air excess ratios. If these measured values are corrected to a fixed O_2 content in the flue gas, the increase is even more extreme. In Scenario III, however, measured NO values remain almost constant, despite up to 50 vol.-% of hydrogen in the fuel gas.

These measurements demonstrate that the flameless oxidation burner is unable to maintain its usually very low NO_X emission levels in the presence of larger amounts of hydrogen in the fuel gas, if the changed composition is not detected and the burner settings are not adjusted accordingly. One possible explanation could be the reduced momentum of the fuel gas jet which reduces the intensity of the mixing process of fuel, air and flue gases which is crucial for flameless oxidation. These results were corroborated by other researchers [23], [24]. It is, however, possible to maintain a flameless oxidation mode even with very high concentrations of hydrogen in the fuel if process parameters such as firing rate and air excess ratio are adjusted. This, however, required, up-to-date data on fuel quality and/or composition to be fed forward to the burner control system (cf. Figure 2, right hand side).

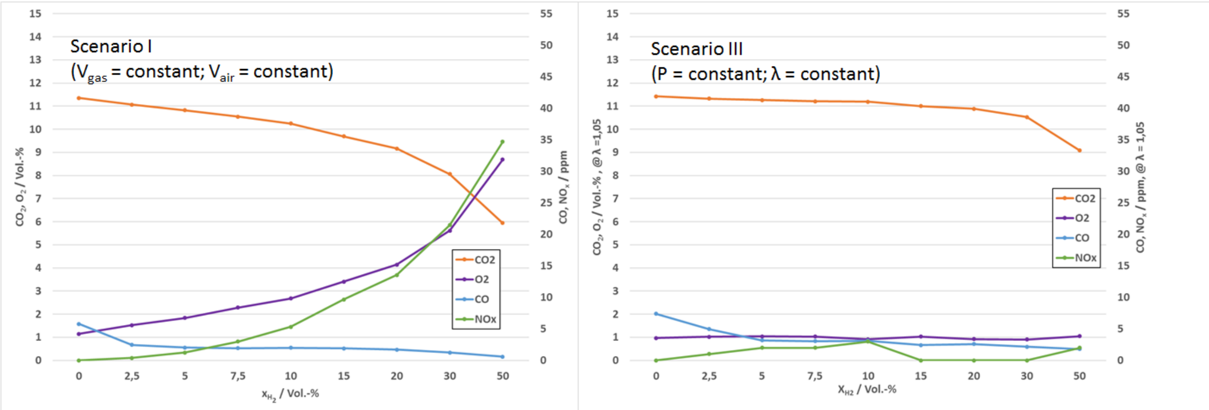


Figure 2: Main exhaust gas species as a function of the hydrogen admixture ratio for different scenarios for Burner 3

The experimental results underline how very dependent NO_X formation is on burner design. Although the three burners investigated in this campaign were operated with similar boundary conditions and identical control scenarios, their responses to the increasing hydrogen content in the fuel gas varied greatly. The only constant in burner performance was that NO_X levels could be maintained if volume flows for fuel and oxidizer were adjusted to take the higher hydrogen contents and its effects on net calorific values and minimum air requirements into account. This highlights the importance of advanced measurement and control systems for the operation of sensitive gas-fired production processes in times of fluctuating gas qualities or variable hydrogen admixture.
From the chemical point of view, it may be a bit surprising to see that higher hydrogen contents in the fuel do not automatically lead to higher NO_X formation. NO_X formation in the combustion of gaseous fuels is usually dominated by the thermal NO_X formation mechanism which is highly dependent on local temperatures. **Figure 3** (right hand side) shows a comparison between net calorific values (NCV) and corresponding adiabatic flame temperatures (at stoichiometric conditions and without air preheating) for various methane / hydrogen mixtures. As can be expected, the volumetric NCV decrease with higher concentrations of H_2 in the natural gas. The adiabatic combustion temperatures, on the other hand, remain almost constant up to a concentration of 10 vol.-% H_2 in the fuel gas (the currently recommended limit according to the German gas quality code) and then increase which would also indicate a higher propensity for increased thermal NO_X formation with increasing hydrogen content. This, however, can be obviously compensated to a certain extent by the burner design, even without adjusting the burner settings.
Figure 3 also points to another important aspect of hydrogen admixture. It compares net calorific values, Wobbe Indices and adiabatic combustion temperatures (at stoichiometric conditions without any preheating) for various CH_4 / H_2 blends. It is obvious that the Wobbe Index is far less affected by increasing hydrogen contents than the net calorific value which is cause for concern for many furnace operators as they usually consider calorific values as a far more relevant gas quality criterion than the Wobbe Index [20].
Also, many industrial combustion processes are temperature-controlled, i. e. a temperature at one or several positions inside the furnace is used as a set point. If local temperatures drop below the set value, the volume flow of gas is increased and vice versa since, for natural gases at least, there is a good correlation between lower heating values (and hence firing rates) and flame temperatures. This control strategy can prove, however, problematic if hydrogen is present in natural gas: in this case, higher flame temperatures may occur despite a reduced calorific value which could cause the control system to respond in the wrong manner by reducing the fuel gas flow, thus further decreasing the energy input into the furnace. While the differences may not be very significant at lower hydrogen admixture rates, this can in principle lead to problems in the future, if and when much larger quantities of hydrogen may be injected into the grids.

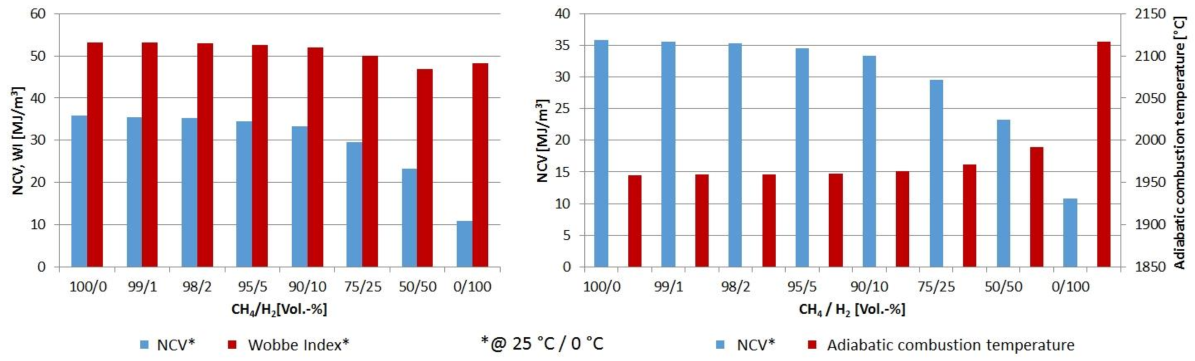


Figure 3: Comparison of net calorific values, Wobbe Indices and adiabatic combustion temperatures for various CH_4 / H_2 blends

In addition to the experimental investigations carried out at one of GWI's semi-industrial test rigs, a number of CFD simulations of the test rig experiments were also performed. The obvious advantage of CFD is the very comprehensive and detailed description of how a complex technological system such as a furnace, may respond to changing boundary conditions such as a different fuel gas composition. Effects can be visualized which are difficult to detect by experimental means.

As part of the project, simulations were carried out for the various burners mentioned previously. In the following, the focus will be on Burner 1, a non-premixed jet burner. All simulations were steady, non-adiabatic RANS simulations (RANS: Reynolds-Averaged Navier Stokes) on a hybrid mesh of about 2 million cells. The shear stress transport (SST) model was used to model turbulence while the chemical processes were described using a non-adiabatic PDF-equilibrium model (PDF: probability density function). Radiative heat transfer was modelled using a Discrete-Ordinates Model.

The overall geometry of Burner 1 consists of a gas lance with a rather elaborate tip through which the fuel gas is injected into the surrounding air flow by numerous orifices. A swirler is mounted on the lance to improve mixing of fuel and air. Both the lance and the swirler are enclosed by a ceramic flame tube. The burner was set to operate with a firing rate of 120 kW and an air ratio of 1.05 when adjusted for the reference gas (GWI-Gas, the same natural gas used in the experimental investigations described previously).

Similar to the experimental investigations, different control scenarios were defined to see how different control strategies are affected by higher hydrogen concentrations in the fuel. Scenarios I and III have already been described above, Scenario II is a scenario where the excess oxygen in the flue gas is monitored and the volume flow of air is adjusted to maintain a constant oxygen concentration in the flue gas. The volume flow of fuel is kept constant as well so that the overall heat input into the furnace changes with changing fuel gas compositions. This is a very common feedback-loop control approach, found in many furnaces today.

Figure 4 shows the effects of the different control scenarios on the flame length when various amounts of hydrogen are admixed to the natural gas. In this image, the flame shape is visualized using iso-surfaces based on dry CO concentrations of a value of 2000 ppm. Previous investigations at GWI showed that this threshold value for carbon monoxide is a good indicator to describe flame shapes in natural gas / air flames.

It is obvious that in Scenario I, the flame becomes increasingly shorter with growing H_2 concentrations. In this scenario, the local air excess ratios increase since the volume flows are not adapted at all to the changing fuel compositions. In Scenarios II and III, on the other hand, the flame lengths at hydrogen contents of less than 10 % in the fuel remain almost constant. Even at higher concentrations of H_2, the impact on the flame lengths is much less pronounced than in Scenario I. This indicates that the flame shape in a non-premixed combustion process is primarily influenced by the air excess ratio and hence the ratio of the gas and air flows. Higher air excess ratios mean that there is an increased probability that the reaction partners in the combustion process come into contact which results in a shortened flame. The changing momenta of the fuel gas flow itself, on the other hand, seem to have an almost negligible effect. If burner firing rate and air excess ratio remain constant (Scenario III), even hydrogen admixtures of 50 vol.-% do not cause a significantly reduction in flame length. Also, the different combustion chemistry due to the hydrogen does not affect flame shape much in such a non-premixed burner system. Premixed burners, for example in residential appliances, but also in large gas turbines, will behave differently in this regard.

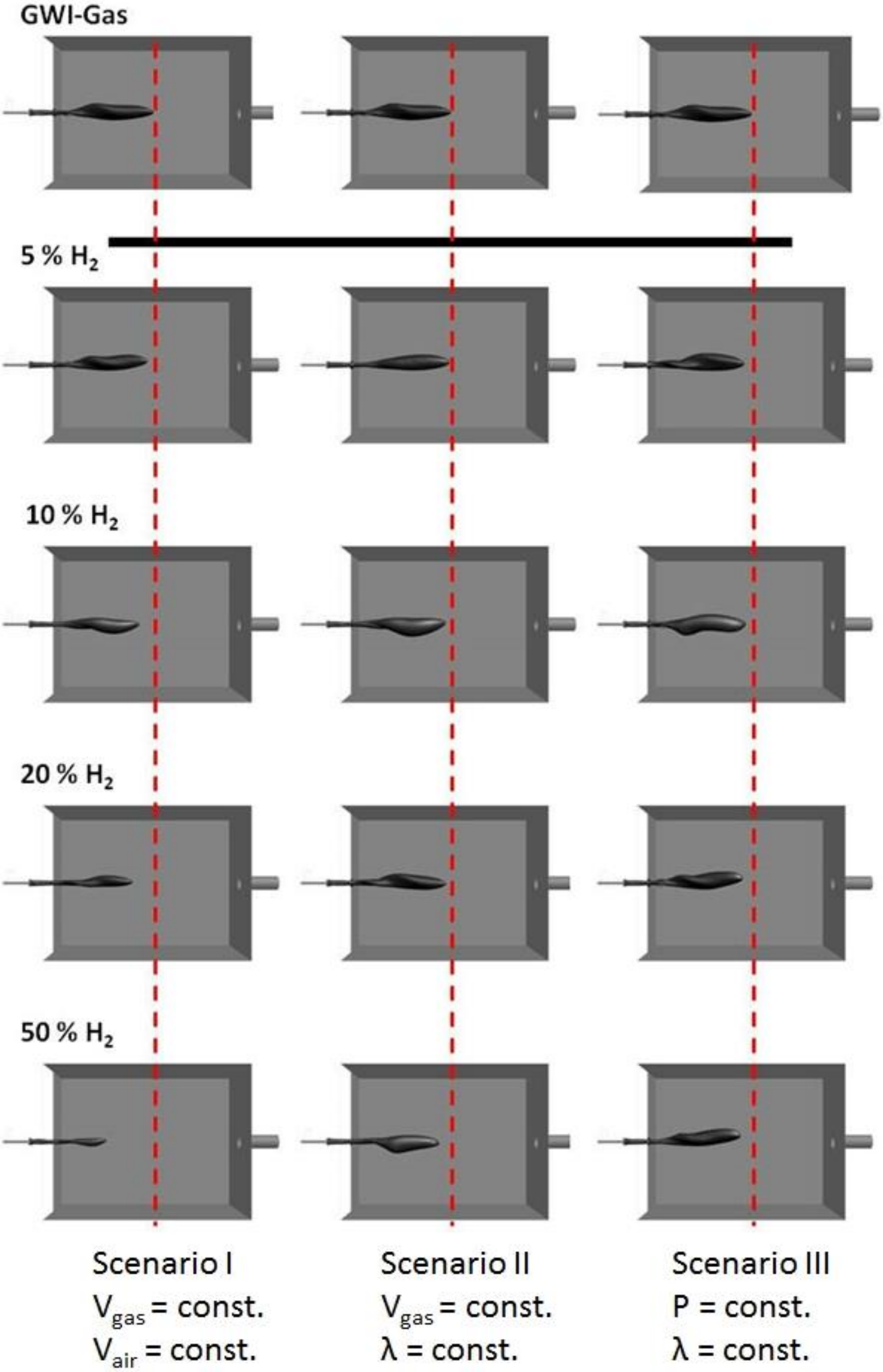
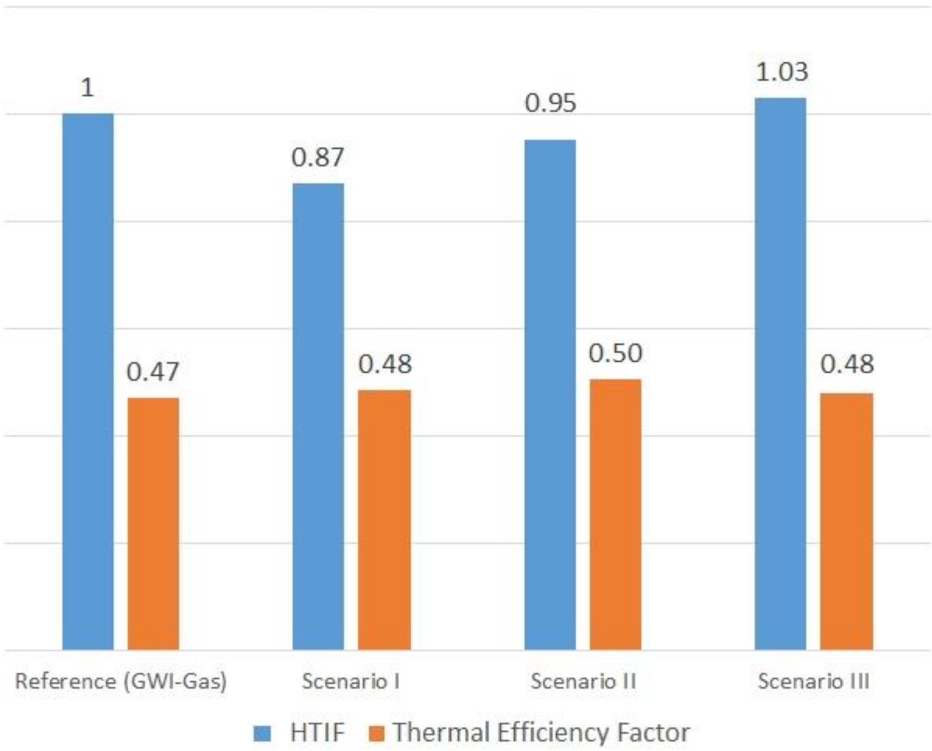


Figure 4: Impact of various hydrogen concentrations on the flame length (visualized by iso-surfaces of the dry CO concentrations at 2000 ppm) in different control scenarios.

Of course, higher hydrogen concentrations in the fuel can also have an impact on the energy balance of the furnace which was also investigated using the CFD simulations. When comparing the simulations, it was found that the thermal efficiency factor $\eta_{thermal}$ was hardly affected by the various scenarios and different levels of hydrogen concentrations in the fuel. This is, however, due to the definition of the thermal efficiency factor, and somewhat misleading. In Scenarios I and II, different hydrogen concentrations lead to different net calorific values and hence, a different energy input into

the furnace, as fuel volume flows are assumed to be constant in these scenarios. In a real-life gas-fired industrial manufacturing process, this could mean that there might not be sufficient heat released inside the furnace for the process to actually work as intended, resulting in problems with productivity or product quality.
Therefore, an additional criterion was defined to quantify the impact of various scenarios and different hydrogen concentrations in the fuel on the performance of the process, the Heat Transfer Impact Factor (HTIF).



$$HTIF = \frac{\dot{Q}_{Load}}{\dot{Q}_{Load,Reference}} = \frac{\dot{Q}_{Wall}}{\dot{Q}_{Wall,Reference}} \qquad \eta_{thermal} = 1 - \frac{\dot{Q}_{Flue}}{P}$$

Figure 5: Impact of 20 vol.-% hydrogen in natural gas on process efficiencies and heat transfer in different scenarios

From the point of view of the furnace operator, the heat flux into the product (e.g. a melt or a slab of metal for heat treatment) is the most important aspect of the energy balance since it will have a direct impact on product quality and productivity. Information on this heat flux can be obtained from the CFD simulation of the reference case (with "pure" natural gas, called "GWI-Gas" here). As there is no actual "product" in the simulations of the combustion chamber of GWI's test rig, the heat flux into the walls is used instead.
Similarly, the heat fluxes into the walls can also be obtained from the other CFD simulations for the various scenarios and hydrogen concentration levels. By normalizing these wall heat fluxes with the wall heat flux for the reference case, the relative impact of hydrogen concentration and different burner control scenarios can easily be quantified. **Figure 5** shows thermal efficiency and heat transfer impact factors for the reference case (no hydrogen in the fuel) and the three different burner control scenarios for a fuel blend containing 20 vol.-% of hydrogen. It can be seen that in the worst-case Scenario I where there is no burner control at all, the HTIF is reduced by 13 % which in real life, would most certainly result in unacceptable performance losses in terms of efficiency and product quality.
If the air excess ratio is kept constant (Scenario II), there is still a noticeable loss of performance (5 %), albeit less pronounced than in Scenario I.
If, on the other hand, both firing rate and air excess ratio remain constant based on gas quality measurement in combination with advanced process control technology, the simulations actually predict a slight increase in heat transfer.

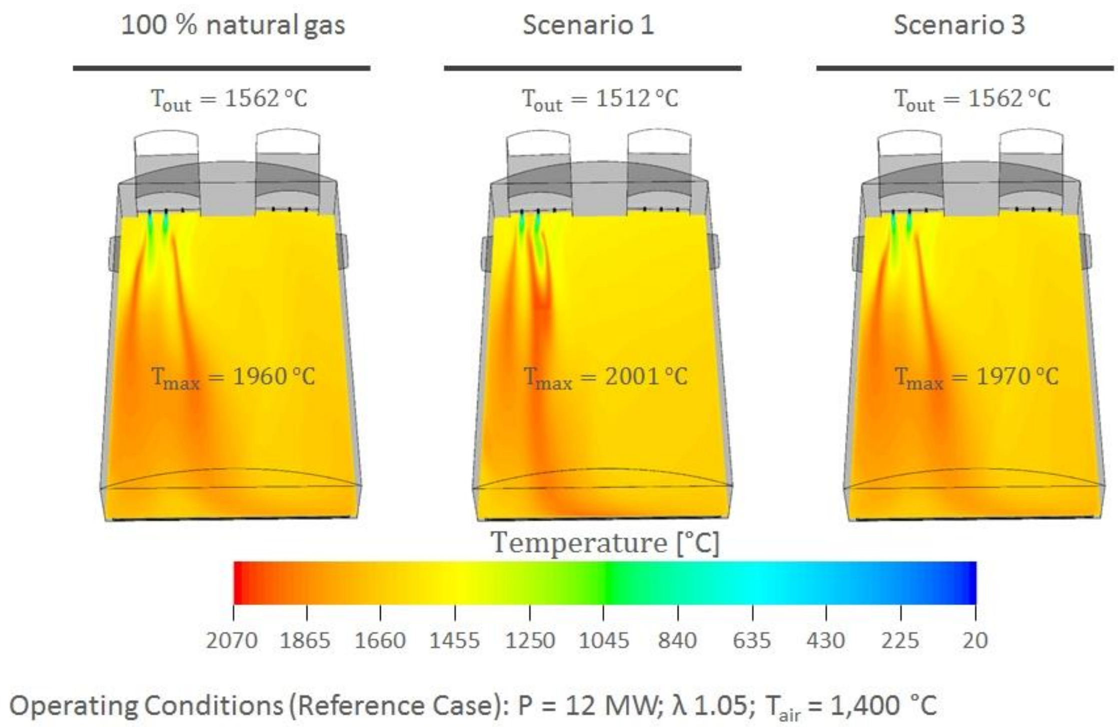


Figure 6: Impact of 10 vol-% H_2 in natural gas on temperatures in a glass melting furnace

In addition to the test rig experiments and the corresponding CFD simulations, the response of a typical regenerative glass melting furnace was also investigated, again using computer simulations. The approach is quite similar to what has been described before: a typical glass melting furnace is simulated using realistic boundary conditions (firing rate 12 MW_{th}, air excess ratio of 1.05 and air preheat temperature of 1,400 °C) and “pure” natural gas as a fuel. This simulation serves as a reference case. Then, different furnace control scenarios and fuel gas blends were applied as boundary conditions and simulated as well. The results of these various cases were then compared to the reference case to describe the impact of both the presence of hydrogen and the different burner control systems on the performance of the furnace in terms of efficiency, heat transfer and NO_X emissions.

Figures 6 and **7** show temperature distributions in the horizontal burner plane for Scenarios I (no burner control) and III (advanced burner control to maintain constant firing rates and air excess ratios) for two different fuel blends, 10 vol.-% H_2 and 50 vol.-% H_2. As is to be expected, the flue gas temperatures T_{out} decrease in Scenario I for both fuel blends, while Scenario III results in relatively constant flue gas temperatures. Maximum temperatures in the computational domain generally increase with increasing hydrogen concentrations.

Similar to the CFD simulations of the GWI test rig, heat transfer impact factors were again determined for the different cases and scenarios (cf. **Figure 8**), although this time, the heat fluxes into the simulated glass melt were used to calculate the HTIFs. As expected, the loss in heat transfer is more pronounced for Scenario I than for Scenario III, though it is interesting to see that in both scenarios, the cases with 50 vol.-% H_2 in the fuel blend actually perform slightly better than the cases with only 10 vol.-% H_2.

Figure 9 shows a comparison of predicted relative NO emission levels in the different simulation runs. In the cases without process adjustment (Scenario I), hydrogen admixture results in drastic increases in NO emissions while emission levels remain much more stable in Scenario III where fuel and air volume flows are adjusted.

Both the experimental investigations on a semi-industrial test rig and the CFD simulations indicate that, from a combustion point of view, even significant concentrations of hydrogen in natural gas are in principle manageable without significant losses in terms of heat transfer and efficiency, or increased NO_X emissions. This requires, however, adequate on-site measurement equipment to quickly detect changes in gas quality due to the presence of hydrogen as well as burner/furnace control systems which can adjust fuel and air volume flows independently to maintain constant firing rates and air excess ratios. This is not common practice in today’s thermal processing industries.

There are also still some open questions: does hydrogen in natural gas chemically interact with products of the metals or glass industries, causing product quality issues? What about possible interactions between hydrogen and refractory materials in high-temperature furnaces, with consequences for furnace lifetime or increased maintenance requirements? Does hydrogen pose a risk to the metal in piping or the burners themselves, e. g. due to hydrogen diffusion and embrittlement?

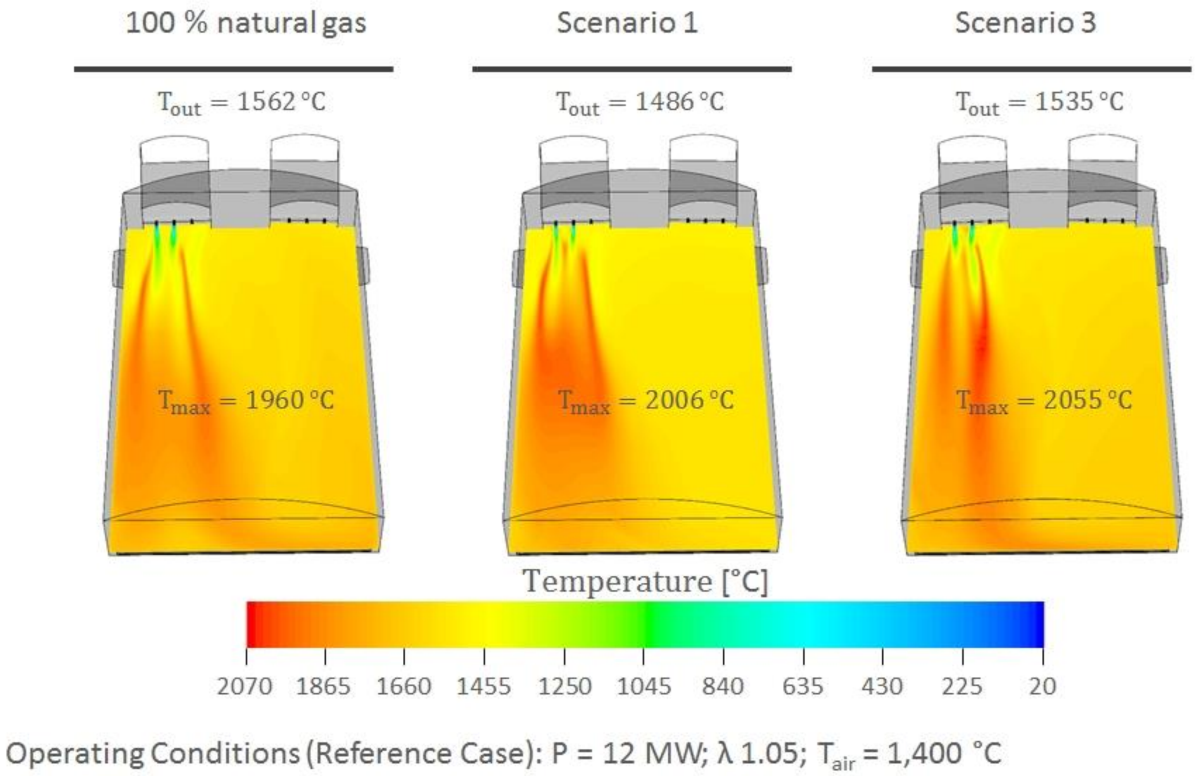
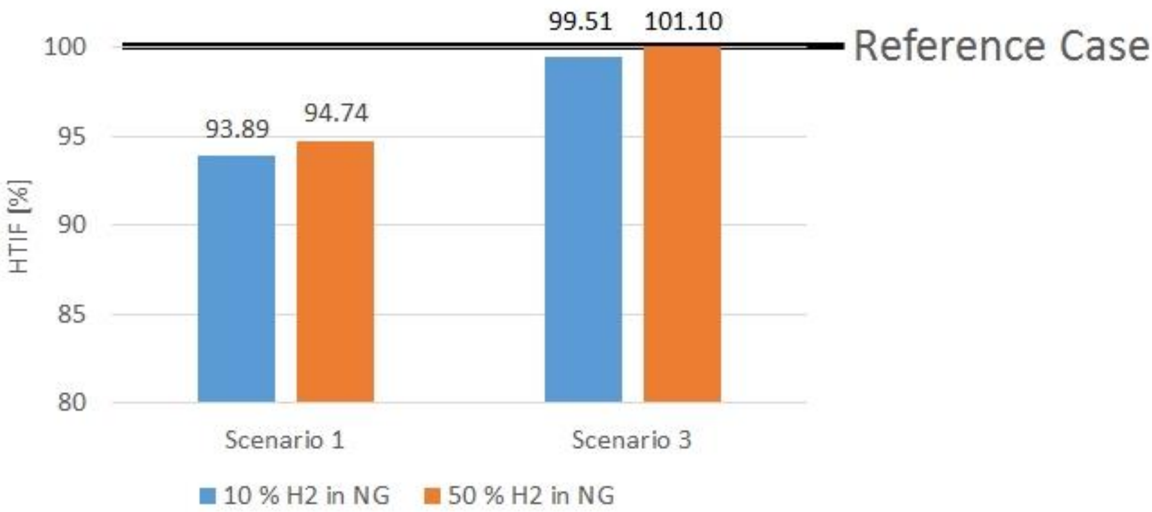
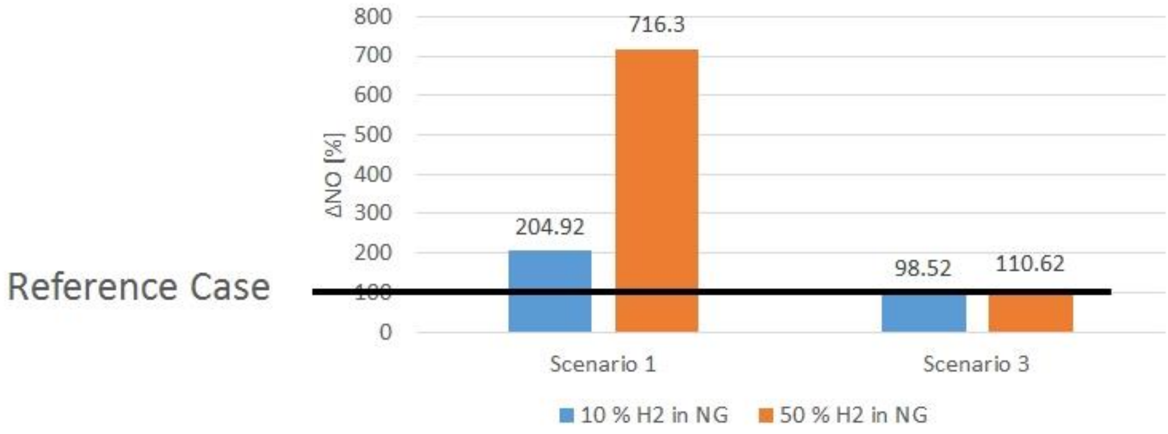


Figure 7: Impact of 50 vol.-% H_2 in natural gas on temperatures in a regenerative glass melting furnace



$$HTIF\,[\%] = \frac{\dot{Q}_{glass}}{\dot{Q}_{glass,reference}} \cdot 100$$

Figure 8: Heat transfer impact factors for different scenarios and hydrogen concentrations in a simulated glass melting furnace



$$\Delta NO[\%] = \frac{x_{NO,Case}}{x_{NO,Reference\ Case}} \cdot 100$$

Figure 9: Predicted relative NO emissions for different scenarios and hydrogen admixture rates in a simulated glass melting furnace

Finally, it has to be pointed out that the results presented here only apply to non-premixed combustion processes as they can be found in many thermal processing furnaces. Combustion technologies in gas turbines and engines are fundamentally different and are much more sensitive to kinetic effects such as increased laminar combustion speeds or self-ignition behavior. The presence of hydrogen is likely to have a much more pronounced effect here which is why manufacturers of both gas turbines and engines are reticent in this regard. Nevertheless, there is a lot of research going on in these industries to prepare for higher concentrations of hydrogen in natural gas in the future [25], [26], [27].
Similarly, the chemical industries with their huge consumptions of natural gas both for process heating and feedstock purposes, will have to be investigated in terms of sensitivity to hydrogen.

Conclusions

As part of increasing integration of wind and solar power into existing infrastructures, "power-to-gas" is being discussed as a possible solution to address the challenge of storing large quantities of energy. A key question of this technology is whether the produced hydrogen can be injected directly into existing natural gas grids or needs to be converted to methane prior to injection. While direct hydrogen injection would be advantageous for the gas supplier or grid operator, one consequence of direct injection will be that end-users will be confronted with larger and fluctuating hydrogen concentrations in the distributed natural gas.

This article gives an overview over some of the main results of a German research project which investigated the consequences of higher H_2 concentrations for combustion processes in thermal processing industries. It was found that if the level of hydrogen in the natural gas is monitored and the firing process adjusted accordingly, the effects of hydrogen on the process can be minimized in terms of efficiency, heat transfer or pollutant emissions. If on the other hand, the systems are not adjusted, the presence of hydrogen will have a negative impact on industrial combustion processes, even if the hydrogen admixture is limited to the currently envisioned threshold of 10 vol.-% in Germany.

The findings of this project underline the growing importance of advanced measurement and control technologies in order to make sensitive large-scale combustion equipment, both in thermal industries and in power generation, more resilient to changes in local natural gas composition, be it due to the injection of hydrogen or to a wider range of sources for natural gas in general.

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