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A review of research on hydrogen admission into the existing natural gas infrastructure

Przegląd prac badawczych dotyczących procesu zatłaczania wodoru do istniejących systemów gazowniczych

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Słowa kluczowe: *Systemy gazownicze, Magazynowanie energii chemicznej, Power-to-gas, Zatłaczanie wodoru do sieci, Dopuszczalne stężenia wodoru*

Streszczenie
W artykule dokonano przeglądu aktualnego stanu wiedzy w zakresie projektów badawczych obejmujących proces zatłaczania wodoru do sieci gazowych oraz jego wpływ na odbiorniki gazowe. Omówiono dostępne w literaturze wyniki badań wrażliwości poszczególnych elementów systemu gazowniczego na podwyższone stężenie wodoru. Zaprezentowano softwarową metodę śledzenia jakości gazu w sieciach dystrybucyjnych i związany z nią problem obliczeniowy sieci w stanach ustalonych oraz omówiono wyniki badań wpływu zatłaczania wodoru na parametry eksploatacyjne przykładowej sieci gazowej.

Keywords: *Gas systems, Chemical energy storage, Power-to-gas, Hydrogen injection into gas grid, Admissible hydrogen concentrations*

Abstract
The article presents the review of the current state of research with the aim of understanding the problems associated with hydrogen injection into the gas grid and its impact on end use. The review focuses on the field of the sensitivity of individual components of the gas system to increased hydrogen concentration. The work presents software-based gas quality tracking problem in gas distribution network and discusses the steady-state modelling and the effect of hydrogen injection on the operational behaviour of the gas grid under consideration.

1. Introduction

Natural gas sector stakeholders are taking actions to develop and deliver projects that assess challenges of the injection of H2 into the existing natural gas infrastructure, and its effect on the end use appliances/processes, in order to support the Hydrogen Economy. Hydrogen is expected to play a significant role in the decarbonization of the gas sector, while utilization of natural gas together with application of carbon capture and storage (CCS) technology is seen as an important scenario that leads to reductions in greenhouse gas (GHG) emissions in hard-to-abate sectors such as the cement industry, iron and steel, chemicals, etc.

With introduction of renewable gases like biomethane and hydrogen, the existing gas transmission and distribution networks, together with the associated facilities connected to them, will contribute to delivering the decarbonisation of the European economy and the goals of the EU Hydrogen Strategy and EU strategy on energy system integration [1,2,3].

The importance of blending hydrogen in gas networks has already been recognized. It is an essential enabling factor in storing excess renewable energy and speeding the decarbonization of heat and industry at low cost. In fact, three hydrogen deployment options, which can co-exist where needed, are now considered [4]:

1. Retrofitting of existing gas grids, which refers to small modifications/adaptations of the gas network that allow injection of certain amounts of hydrogen up to a technically-sound threshold of H2/CH4 mixture (i.e. blending).
2. Repurposing of existing gas grids, which implies converting an existing natural gas pipeline into a dedicated hydrogen pipeline.
3. Construction of new dedicated hydrogen infrastructure, such as one proposed in an open initiative of European Hydrogen Backbone [5].

While blending is expected to be a transitional solution, since full decarbonisation of the EU economy requires a much greater penetration of hydrogen in the EU energy mix than what could be accommodated through blending. It has however some advantages:

- Using gas-hydrogen blends in the short and medium term achieves a larger GHG reduction at a lower systemic cost than by using only new dedicated infrastructure to deliver hydrogen.
- sector coupling between electricity and gas enhances system-wide resilience by integrating surplus intermittent renewable electricity, reducing power network congestion and providing short-term flexibility and energy storage.
- Injecting hydrogen into gas transmission and distribution pipelines provides renewable energy to consumers currently connected to the gas network.

Hydrogen admixtures in the gas network require support of a robust system of certificates/guarantees of origin (GOs) that would allow monetisation of hydrogen injected while reducing the need for public subsidies. Additional interoperability measures at technical and commercial levels would be required to facilitate intra-EU cross-border trade of gas blends. The question arises of whether and to what extent

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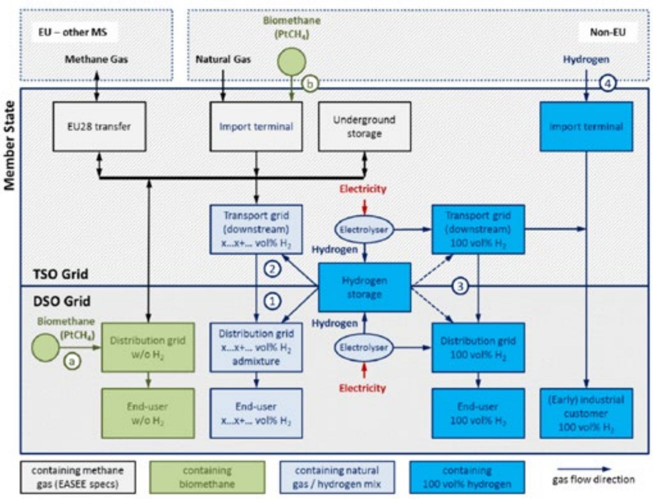
the transitional role of blending hydrogen with natural gas and transporting the resulting mixture using the current gas network should be governed by blending standards and whether they should be harmonised across Europe.

2. Regulatory aspects

According to [6] the negotiation of an EU wide standard for admixture of hydrogen may take a long time, especially given the regulatory complexity and diversity of stakeholders. For example, negotiating the standard CEN/TC 408 "Natural gas and biomethane for use in transport and biomethane for injection in the natural gas grid",62 with the aim to harmonise the quality of biomethane across the EU, took six years from 2011 to 2017. With over 470 million gas appliances in the EU that would be affected by a change in gas composition, and given that the sectors Industry and Power generation, which have some of the most sensitive end-users and account for over 50% of total gas use in the EU, finding a common denominator will be a challenging task. The current practice is that permitting hydrogen admixture to the gas network is considered on a case by case basis, with the outcome that Power-to-Gas (PtG) facilities are run on a demonstration basis or 'by exception'.

As an alternative approach to an EU wide harmonization, report [6] points out that it might be easier and quicker to explore options for creating "favourable" regulation at DSO level in individual Member States that allow the creation of locally isolated sections of the network that run on higher hydrogen concentrations, favourably at 100% hydrogen, as is being suggested for trial in the UK (see for example the Leeds CityGate project [7] or HyHouse [8], HyDeploy [9], HyNet [10] and Hy4Heat [11]) and in Germany (see H2HoWi project [12]).



Rys. 1. The overall concept and associated boundary restrictions for injection of renewable gases into the gas network. Source: European Commission [6]

Figure 1 illustrates the major constraints with respect to the injection of hydrogen and biomethane into the gas network, taking into account the TSO and DSO perspectives. Admixture of hydrogen to border-crossing gas transmission pipeline in one Member State, may carry hydrogen to any location in the EU downstream of the injection point at an uncontrollable admixture level. Unless locally removed from the gas mixture this hydrogen could potentially affect other gas consumers and conflict with the current regulations on gas quality which are different for all Members States. Research projects aimed at investigating different concepts for hydrogen separation from natural gas mixture are therefore in progress to determine economically viable options to safeguarding hydrogen sensitive applications, see for example HYPOS project [13], investigating membrane separation technology.

Admissible hydrogen concentrations in natural gas systems

It must be emphasised that the hydrogen tolerance in the gas transmission and distribution systems should specifically be assessed per case, based on location (network structure), gas composition, gas flow rate, end-user appliances, etc. At present, different Member States in Europe – and other jurisdictions around the world – impose different limits on hydrogen blending in natural gas networks. Current natural gas pipeline regulation varies from country to country, but typically stipulates very low levels of hydrogen blending, as illustrated in Figure 2. The allowed hydrogen content in the gas network specified by the national regulator for work-related health and safety in the UK is currently ≤0.1% (molar) [14]. Among those EU Member States in which blending is permitted, the highest limits apply in Germany (10%, but only if no CNG filling station is connected to the network, otherwise the limit is 2%), in France (6%), in Spain (5%) and in Austria (4%). However, many jurisdictions do not (yet) allow hydrogen blending into the natural gas network. It is clear that, if blending is accepted as a transitional arrangement to facilitate the development of the hydrogen sector, at least in its initial stages, the seamless functioning of the internal energy market requires that harmonised standards be introduced for the maximum admissible hydrogen share. It remains an open question whether current natural gas infrastructure is ready to act as renewable energy storage with higher concentrations of hydrogen.

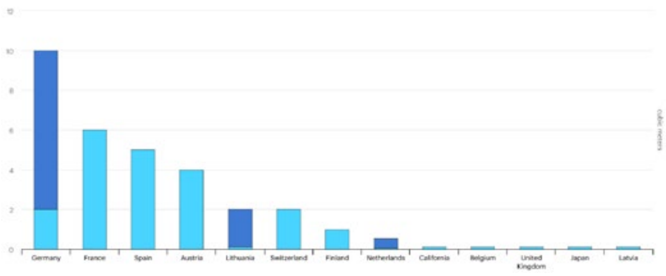


Fig. 2. Limits on hydrogen blending in natural gas networks (% hydrogen (volume)). Source: IEA (2020) [15]. The conditional limits shown reflect these parameters: in Germany if there are no compressed natural gas filling stations connected to the network; in Lithuania when pipeline pressure is greater than 16 bar; in the Netherlands for high-calorific gas, higher limit for Lithuania applies when pipeline pressure is greater than 16 bar pressure.

Several studies have considered the possibility of conversion of existing natural gas pipelines to carry hydrogen. Early research effort on studying the sensitivity of gas value chain to the increased hydrogen concentrations was reported in [16]. Research on hydrogen-natural gas systems has attracted increasing attention in recent years. In Refs. [17] and [18], the influence of the injection of H2 into natural gas pipeline systems was studied in a very comprehensive manner. Both studies identified five functional areas, namely gas transmission, gas storage, grid/pressure regulation and metering, gas distribution, and end use, that span 30 and 38 core business processes in [17] and [18], respectively. In [17] the amount of hydrogen that is technically allowable per process was reported with three thresholds, wherein: (i) mixing of hydrogen is harmless, (ii) technological and regulatory adaption is required, and (iii) research and development is still needed, while in [18] six thresholds were identified, corresponding to the following knowledge statuses: (i) no significant issues in available studies, (ii) Mostly positive results from available studies. Modifications/other measures may be needed, (iii) technically feasible, significant modifications/other measures or replacement expected, (iv) currently not technically feasible, (v) insufficient information on impact of hydrogen, R&D required, (vi) conflicting references were found, R&D/clarification required. Since study [17] has been incorporated into [18], this review will cover only selected aspects reported in [18].

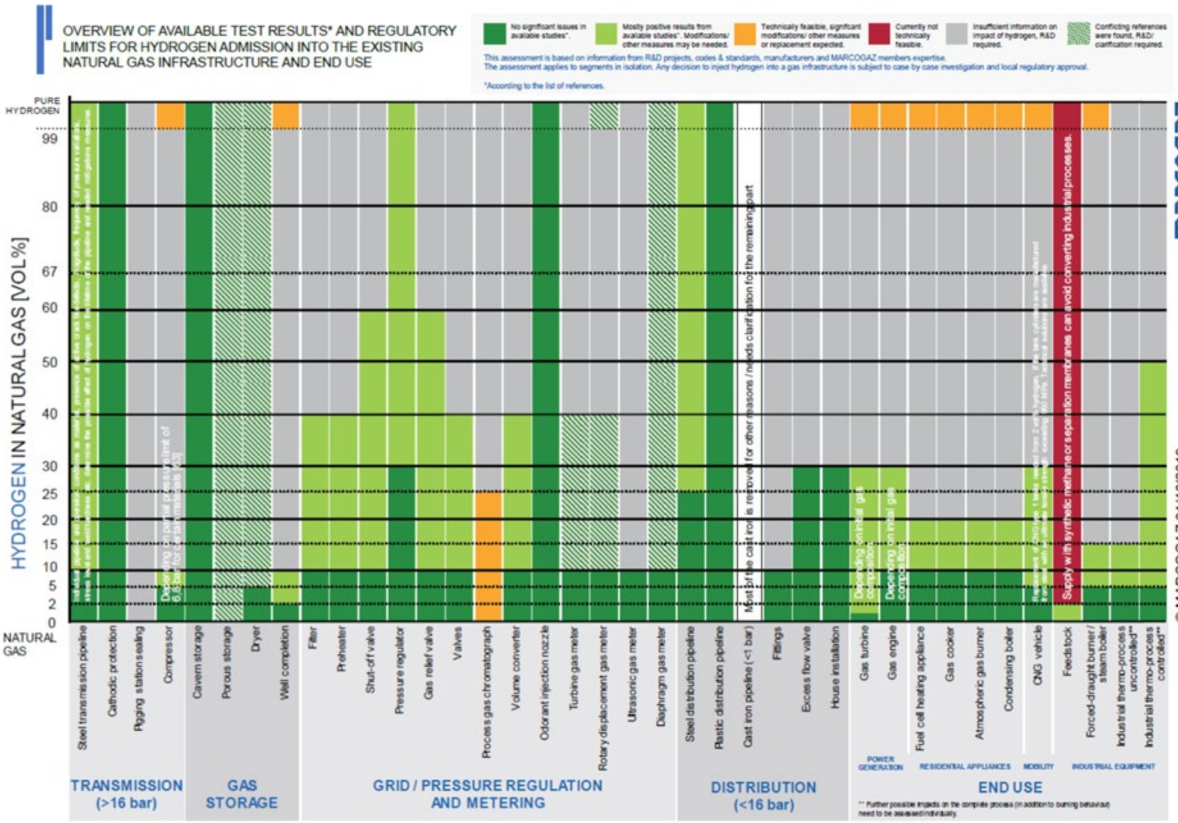


Fig. 3. Limits for hydrogen admission into the existing gas infrastructure. Source: Marcogaz [18].

The first cluster on the left-hand side of Figure 3 with four bars shows the results of the studies with respect to the processes related to gas transmission, which include: steel pipeline, cathodic protection, pigging station sealing and gas compressor. The volume fraction of hydrogen in the natural gas mixture with no adverse effects varied from 5% for the pipeline compressor to 10% and 100%, for the material and for the cathodic protection, respectively. Despite concerns about hydrogen embrittlement, natural gas transmission pipelines can cope well with hydrogen addition up to 10%. Individual pipeline and operation conditions as material, presence of active crack like defects, magnitude, frequency of pressure variations, stress level and weld hardness etc. determine the possible effect of hydrogen on the lifetime of the pipeline and needed mitigations measures. The limitation imposed on the operation of the compressor and considered as "non-critical" was 10%, while pure hydrogen conditions were considered as technically feasible, however requiring compressor replacement. The addition of hydrogen requires the compressors to operate at higher speeds. This will, at some level of hydrogen content, require re-staging compressors (for example from 2 to 3 impellers). The higher speed requirements, and the higher power consumption may also require the installation of additional units [19].

As shown in second cluster of Figure 3 pure hydrogen does not pose any difficulty for gas storage in salt caverns. Conflicting references were found with respect to aquifers. In case of aquifers (possibly oil/gas depleted fields as well) serious problems associated with bacterial growth were reported in the literature, i.e. hydrogen metabolism during growth of sulfidogenic bacteria resulting in the production of H_2S. Further research is needed to explore this issue as there is no possibility at the moment to define a limit value for the maximum acceptable hydrogen admixture for natural gas storage sites in saline aquifers.

The next group in Figure 3 refers to metering and regulating systems. Attention should be given to existing process gas chromatographs, which use helium as the carrier gas and are unable to detect hydrogen. The problem can be solved by providing additional separation column for hydrogen detection with argon as carrier gas, on a retrofit basis, or by replacing the existing gas chromatographs with the new ones licenced for hydrogen metering [20]. Major elements of the metering and regulating systems are expected to be able to accept 10%vol. without modification. Some problems with hydrogen admixtures above 10% come with flow computers equipped with volume correctors implementing algorithm for the solution of GERG-88 Equation of State (EoS) as an example. Current industry standards require the uncertainty of compressibility factor introduced by EoS to be below ±0.1% for custody or fiscal transfer. GERG-88 provides this level of uncertainty with hydrogen content in natural gas mixture not exceeding 10%mol. Newer real gas models for hydrocarbon mixtures, namely GERG-2004 and GERG-2008, are for wider range of natural gases and other mixtures, therefore fulfil this requirement for higher concentrations of hydrogen. For example, under typical pipeline gas pressure-temperature conditions the uncertainty of density calculations from GERG-2004 EoS for a binary mixture of methane-hydrogen with H_2 fraction in a range of 15 75%mol. is ±(0.07 0.1)%.

Compared to the transport and storage elements of the gas value chain, distribution presents the least technically challenging component (see fourth group in Figure 3). Leakage from the fittings of the pipes are causing a flow rate of 25% higher with hydrogen than with natural gas. Gas distribution and in-house pipework systems, where leakage was shown to be negligible, should cause no problems. Presumably special attention will have to be drawn to leak detection devices and ATEX zoning. However, since hydrogen-natural gas mixture has a lower calorific value compared to natural gas, customers located downstream of the injection plant might be undersupplied relative to others in terms of chemical energy rate (power nominations). For example, a binary mixture of methane and hydrogen at proportions by volume/molar percent of 85% and 15 %, respectively, requires 10% higher flow velocity compared to that of the flow of pure methane in order to maintain constant energy delivery in the distribution networks of low and medium pressure (gauge pressure of 10 kPa and 0.4 MPa, respectively). Higher flow velocities of the hydrogen-natural gas mixture may have an impact on the operation of excess flow valves at service lines.

The last cluster at the right hand side of Figure 3 shows the sensitivity of end-user gas appliances to the increased hydrogen concentrations in natural gas mixture. The most severe problems are reported for steel CNG vehicle tanks. The negative effects of hydrogen on the mechanical properties of steel have been known for many years and a restriction on the maximum hydrogen admixture in CNG vehicle fuel of 2%vol. has been placed by DIN and ISO standards [21,22]. Hydrogen is an active deleterious agent when present in contact with steel. It has been shown that steel becomes permeable to hydrogen under high pressure. Simultaneously, embrittlement of the material occurs even at room temperature. The effects are aggravated by stresses and by the simultaneous presence of nitrogen, ammonia, and hydrogen sulphide. Steel can be made more resistant to hydrogen by lowering the carbon content in solid solution and by binding the remaining carbon into stable, dispersed carbides [23]. Quenched and tempered steel 34CrMo4 is employed exclusively for CNG tanks in Europe owing to its compatibility with hydrogen, provided that the tensile strength of the steel is less than 950 MPa, and that the inner surfaces of the cylinder have been inspected for allowable defects [20]. Replacement of CNG type 1 tanks needed from 2 vol% hydrogen, if the tank cylinders are manufactured from steel with an ultimate tensile strength exceeding 950 MPa.

Dry low emission (DLE) combustion burners in currently used gas turbines are tuned for optimum operation given current fuel specifications. Turbine manufactures place limits on hydrogen volume fractions in natural gas. After tuning and/or modifications (lean premixed combustion without dilution and/or water injection), much of the frontrunner gas turbine products operate tolerating up to 20% volume hydrogen admixture (or even 30% vol. H2) [24,25]. In some of these cases a de-rating of the gas turbine engine is still required (de-rating accomplished by reduced flame temperature). The main challenges in making existing gas turbine usable with 30% hydrogen mix are flashback, combustion pressure fluctuation, and NOx. Flashback is a phenomenon where the flames inside the combustor travel up the incoming fuel and leave the chamber [26]. Flashback occurs commonly in hydrogen-enriched gas turbines, since hydrogen burns rapidly (Figure 4).

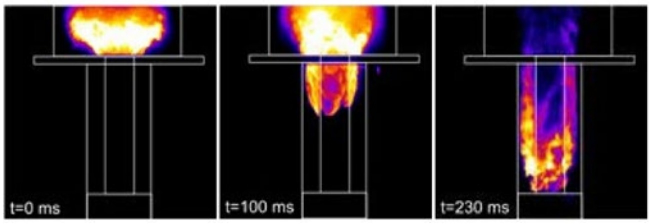


Fig. 4. Illustration of flashback phenomenon. Source: Graphical abstract of DOE NETL grant DE-FE0012053 [26]. Retrived from: https://www.netl.doe.gov/node/933

Internal combustion gas engines are widely used in CHP installations and in CNG vehicles. The effect of hydrogen on NOx emissions and knock resistance due to increased in-cylinder peak pressures and combustion temperatures need to be examined in the above applications. The engines need to be readjusted and/or modified from case to case, given the decrease in methane number of the resultant blend used as a fuel [27,28].

Laminar and turbulent flame speeds are important combustion parameters for atmospheric burners of the gas boilers and for combustion chambers in the gas turbines. For a binary mixture with 80% methane and 20% hydrogen a 5% increase in the laminar flame speed was observed in [29]. With regard to gas turbines, the effect of hydrogen on turbulent flame speeds is stronger, and the increase reported in [30] was 25% for the same admixture level of 20%.

In conclusion of the report [18] it has been stated that major elements of the gas transmission, storage and distribution infrastructure and residential gas appliances are expected to be able to accept hydrogen concentration of 10% vol. without modification. Higher concentrations (above 20%) can be reached through R&D. Mitigation technologies, such as separation membranes and methanation (supply with synthetic methane) exist, and can be used to reduce hydrogen concentration in gas grids. They are considered to be very important to protect sensitive equipment and processes. Installed beforehand they should help avoid the need for converting industrial processes, however further R&D is required in such cases.

Gas quality tracking with software simulation tools

Hydrogen addition reduces the calorific value of the gas mixture measured by volume [31]. This effect may lead to higher gas flow rates in pipes and significant underpressures, which have serious impact on the reliability of the pipeline transport. In order to get a fundamental understanding of how power-to-gas equipment impacts the pressure and flow of gas in the network, computer simulations must be performed, that demonstrate basic hydraulic properties of the network and scenarios of new operating conditions that dispatchers must respond to. Gas quality tracking models are necessary for accurate allocation of demand for gas to each offtake, estimation of the capacity of the gas network, and for monitoring increased hydrogen concentrations

The flow model of hydrogen-natural gas mixture under steady-state conditions in a single pipeline has been investigated in [32,33]. The studies assume isothermal flow condition and horizontal layout of a pipeline. The effect of hydrogen injection to the tree-shaped gas network was also studied in [34]. More recent studies concerning hydrogen-natural gas mixture flows in looped network are reported in [35, 36]. The former is devoted to small scale gas distribution network with input data describing the gas consumption assumed in units of energy, the latter to the transmission network, wherein non-pipe units (compressor stations) are also present. The Newton-nodal method was used for the solution of the set of nodal equations describing the gas network in the above research studies, which precludes their application to a large scale system due to poor convergence characteristics and method's sensitivity to initial conditions [37].

In the studies [38-40] the Newton loop-node method [28] was used for the solution of hydraulic and mass transport (gas quality tracking) model in a larger-scale gas distribution networks with complex structures, including different pressure levels and non-pipe elements.

When dealing with gas quality tracking problems, the preferable solution is to rewrite the flow equations in terms of the energy flow

$$E=HQ_n \qquad (1)$$

where E is the gas chemical energy flow rate and H is the gas calorific value.

At a network node a perfect mixture of all entering gases is assumed. As a result all gases leaving a node have the same quality (the nodal quality, e.g. gas calorific value). Denoting the nodal quality at node i by Hi, the energy balancing equation is

$$\sum H_{\text{in}} Q_{n\,\text{in}} = \sum H_{\text{out}} Q_{n\,\text{out}} = H_i \sum Q_{n\,\text{out}} \qquad (2)$$

where H_{in} is the quality of the gas entering node i with a flow rate Q_n in.

Substitution of volumetric balance equation $\sum Q_n$ in = $\sum Q_{n\ out}$ yields

$$H_i = \sum H_{\text{in}} Q_{n\,\text{in}} / \sum Q_{n\,\text{in}} \qquad (3)$$

This mixing rule is valid for each property that can be represented by a linear relation in the components.

The network simulation begins with an initial estimate of flows in each pipe that may not necessarily satisfy energy flow continuity. Once a distribution of the flows in a network has been calculated, the gas qualities at the nodes is to be calculated. The set of equations is arranged in a matrix form

$$\mathbf{Gh=b} \qquad (4)$$

where **G** is the coefficient matrix consisting of the flows, dim **G** = ($n \times n$) = ($n \times n$), h is the vector with nodal qualities, b is the right hand side vector containing the sums of products of quality and flow of the supplies. If there are branches with zero flow, solvability of the system of quality equations needs to be maintained.

Gas quality tracking is described by the following procedure:

1. give all the nodes an initial quality,
2. calculate the nodal pressures and pipe flow rates in the network,
3. repeat:
   – recalculate the quality at each node,
   – recalculate the pressures and flow rates in the network,
   until the change in quality is negligible.

Tests have shown that above iterative method is very robust, but it needs to be stressed that the simulation of blending of gases is more complicated, since original pressure drop is based on volumetric flow, while demand is described in terms of energy flow and gases leaving a node via several branches have equal quality.

Gas quality tracking example

Figure 5 shows the structure of gas distribution network simulated in [39], which was fed from an upstream high pressure gas transmission pipeline through two city gate stations with a nominal capacity of 9000 m3/h (marked with square symbol in the upper and lower part of Fig. 5). Currently they provide gas with uniform quality of 39.5 MJ/m^3. The total length of the pipelines is 94 km, diameter range (40-225) mm, load range 10-610 m^3/h, with major loads of around 200, 250 and 610 m^3/h.

Fig. 5. Structure of the gas distribution network. Source: [39].

The simulations were performed for the peak winter demand condition with the use of the SimNet SSV software [41] implementing steady state simulation algorithm with gas quality tracking module The predictions of the minimal delivery pressures in medium pressure grid was 219.4 kPa. The results also helped to identify 9 pipeline sections with relatively high gas flow velocities. The highest value of 16.6 m/s has been reported, which clearly showed that this branch was a network bottleneck. In the study [38] the potential location of a new renewable gas source from power-to-gas plant in Source 2, located in the northern part of the grid was considered. The analysis was aimed at identifying the range of the network impacted by the new source, and at assessing its effect on the gas quality at the delivery nodes. The simulations were carried out with the assumption that hydrogen is to be injected at Source 2 with two scenarios corresponding to hydrogen admixture of 10 %vol and 20 %vol of the current capacity of the station, respectively. The results of the calculations for the above scenarios in the form of thematic geographic information system (GIS) maps showing the distribution of gross calorific value of the natural gas-hydrogen mixture in the network are shown in Figs. 6 and 7. The results show that the minimum GCV in the network was 37.784 MJ/m3 in the first scenario and 35.253 MJ/m3 in the second scenario. It should be noted that the minimum gross calorific value of the group E high methane gas admitted to trading on the Commodity Market in Poland is 38.000 MJ/m3, which leads to the conclusion that given the composition of the currently transported gas, the proposed location of the new renewable gas source prevents hydrogen injection at a simulated rates. Selected node labels in Fig. 7 marked in red color indicate the gross calorific value of the gas below the required level (a critically low level of 37.00 MJ/m^3 has been adopted for creating the thematic GIS map).

Fig. 5. Gross calorific value distribution for the first scenario (natural gas–hydrogen mixture with volume concentrations 90%/10%). Source: [39].

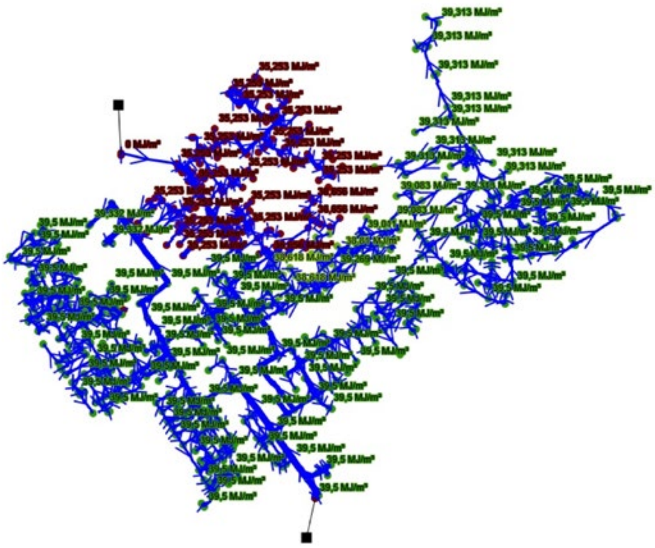


Fig. 6. Gross calorific value distribution for the second scenario (natural gas–hydrogen mixture with volume concentrations 80%/20%). Source: [39].

Conclusions

The integrated natural gas/hydrogen networks are considered as an important element of the future integrated energy systems and interesting option for decarbonisation and increasing flexibility in energy systems.

The amount of hydrogen that can be safely injected into the natural gas grid strongly depends on the gas composition at the injection point, topology of the network, and the appliances downstream to the injection point. Even if a constant admixture rate may be technically feasible assuming the availability of spare capacity in the existing distribution systems, the cost-benefit of the necessary adjustments might be questionable and cannot be conclusively answered today. From this perspective, a direct shift to a dedicated hydrogen (pipeline) infrastructure may be a more preferable and cost-effective approach to supply hydrogen to the industry branches seeking to de-carbonise their operations, such as the steel, chemical or cement industry. Dedicated hydrogen pipelines would avoid the necessary and potentially incremental adjustments of the existing gas infrastructure and end-use applications.

Operating experiences from the currently reported hydrogen injection projects indicate that, with certain restrictions, admixture of up to 20%vol. is not critical for the pipeline infrastructure, however may violate quality constraints related to group E high methane gas specifications. Designing an integrated natural gas-hydrogen network of appropriate capacity may present a considerable logistical challenge requiring guidance and planning based on the solution of hydraulic modelling and simulation problems.

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