Hydrogen Blending into GB Gas Distribution Networks

Fuels Industry UK Response

1.

a) Do you have any concerns around the safety or usability of hydrogen blends of up to 20% by volume in the GB gas distribution networks?

By its nature natural gas is a highly flammable material and should be handled accordingly; because of this we agree that there are inherent concerns regarding the safety and usability of natural gas blends that do, or not, contain hydrogen at up to 20% by volume.

A number of studies providing technical information on this area are available [1,2,3,4,5]. We note that the HyDeploy and Project Union feasibility study will be submitted to DESNZ and the HSE for review, and that we understand that the conclusion of these works are that minimal changes would be required to accommodate the blends of up to 20% hydrogen.

Additionally, we would reference technical bodies such as the Combustion Institute [6] and well as Professor Peter Lindstedt (Imperial College and former editor of Combustion and Flame) [7] who is a leading authority on such issues.

b) If so, is this dependent on whether the blend is a fixed or variable percentage (up to 20% by volume)?

The concentration of hydrogen is known to have significant effects upon the combustion of methane. Fuels Industry UK would refer to the expert literature and contributors referenced above. In terms of usability, all pipelines whether gas or liquids work to tightly controlled specifications. As we outline in our response to Q1 .c below, a range of compositions may be accommodated in a refinery facility; however, a rapidly changing variable composition in a short space of time is not anticipated to be beneficial, even for "simple" combustion applications due to the effect that these changes have on large scale heating operations.

The exact implications are not immediately obvious at this high level of consultation, but uniform product delivery will be critical to certain applications and OEMs are most likely to understand the key issues as it pertains to their own equipment.

Finally, the benefits of the proposal may be more limited than anticipated due to high seasonal variations in heat (and therefore gas) demand, which limits the amount of low carbon hydrogen that can be injected into distribution networks over specific periods. For example, a member's plant currently injects into a specific medium pressure tier of the grid; in summer

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[1] https://www.nrel.gov/docs/fy23osti/81704.pdf
[2] https://energypost.eu/blending-hydrogen-into-the-gas-network-the-challenges-of-pipeline-fractures-faster-flow-rate-more/
[3] https://www.energynetworks.org/newsroom/hydrogen-blending-what-is-it-and-why-does-it-matter
[4] https://hydeploy.co.uk/app/uploads/2022/06/HyDeploy-Close-Down-Report_Final.pdf
[5] https://www.ofgem.gov.uk/publications/ngt-project-union-feasibility-phase-decision
[6] https://www.combustioninstitute.org/
[7] https://www.researchgate.net/profile/Peter-Lindstedt-2

this is limited to 3MW of gas injection due to low demand. If this is low carbon hydrogen at a 20% blend limit (equivalent to around 8% by energy), the maximum hydrogen injection over the summer months would be around 240 kW, which is too low to be of practical use. There are areas of the gas network that have significant year-round demand such as those with high industrial use or the local transmission system; the national transmission system would also be able to accept significant amounts of hydrogen throughout the year. However, the majority of the network will only be able to accept small amounts of hydrogen during the summer. Alternatively, DESNZ could consider asking industry to consider compressing gas back up to the network, which is used in other countries such as France. We would advise further work to be carried out to investigate this potential issue and to identify areas of the UK where hydrogen blending may be useful.

c) If applicable for your project, do you anticipate any cost impact to your business (e.g., from replacing equipment, adjusting production levels, or requiring deblending equipment and processes)?

Most refineries in the UK have a Natural Gas connection with flow meter and online quality (Gas Chromatograph or GC) measurement. The capacity of the line and equipment may have to be calibrated and / or modified to enable accurate readings. Once inside the industrial complex it is unlikely that further mods will be required as refinery fuel gas systems can typically cope with a wide range of H2 concentrations, which is relatively stable in composition between 0%v to 70%v without changes to instruments, equipment, or settings of control and/or safeguarding systems.

Potential cost impacts will also depend on whether facilities are supplied by the "distribution" network, or the "national transportation" network.

d) If applicable, how long would you require to prepare your facilities to accept fixed or variable hydrogen blends? Would there be a substantive difference depending on whether the blend is a fixed or variable percentage?

Fuels Industry UK cannot comment on this question in detail.

However, the exact requirements to accommodate fixed or variable hydrogen blends are likely to vary by location depending on the existing infrastructure in place.

Typically increasing hydrogen requires changes to hazardous area classification that may require instrument / electrical changes. It may also require burner, air rate, abatement technology all that have significant lead time. Variability is a challenge in that all equipment is then required to operate over a wider range.

Industry is always grateful for certainty as far in advance as possible to adequately prepare and implement any changes which may be required.

e) Please provide supporting evidence about any impacts you may expect and estimates for the costs of mitigation, if applicable.

Fuels Industry UK cannot comment on this question in detail. However, the mitigation requirements are likely to vary by location depending on the existing infrastructure in place.

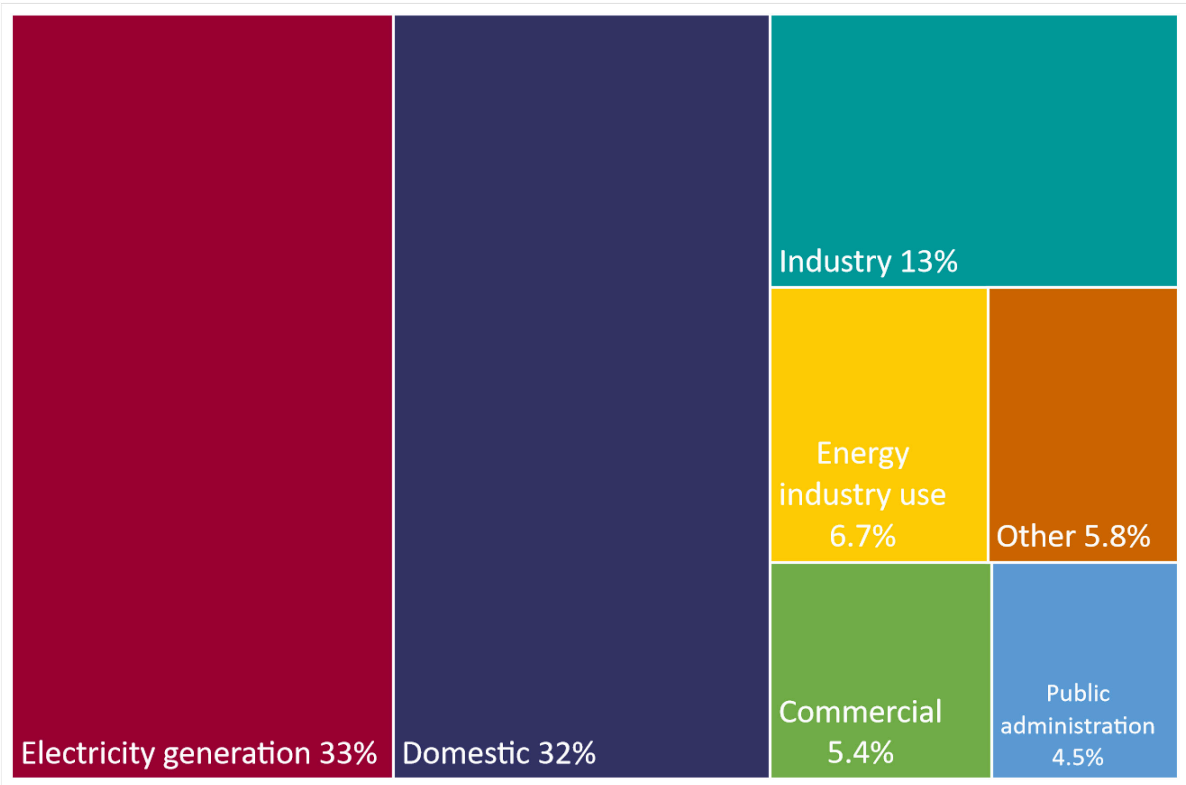
Typically increasing hydrogen requires changes to hazardous area classification that may require instrument and/or electrical changes. It may also require burner, air rate or abatement technology all that have significant lead time. Variability is a challenge in that all equipment is then required to operate over a wider range.

2. Do you have any additional views or concerns associated with blending hydrogen into GB gas transmission networks that have not been identified within this chapter? Please provide evidence to support your response.

We agree with the comments relating to the use of interconnectors for gas transmission with the European Continent. There is a risk that if the introduction of hydrogen is not harmonised then there will be a disconnect on the levels of hydrogen in the gas networks. This could cause issues for either the UK, or European network, depending on the speed of introduction. If Europe moves on hydrogen blending first, then the UK could either be forced to accept gas containing hydrogen or suffer resilience issues if it refuses to accept material through the interconnection system. A harmonised approach is therefore strongly recommended.

However, there is an apparent contradiction present with introducing significant quantities of hydrogen in the gas network when the UK uses 30-35% of its gas supply to create electrical power.

Figure 1: Chart 4.2a Sectoral consumption of natural gas, 2022 [8]



Using either gas (via blue hydrogen production) or green power (via electrolysis) to produce hydrogen, then to re-burn this to produce electrical power generates an inherent inefficiency. Therefore, if hydrogen is to be introduced into the gas main, it needs to be directed at mainly domestic user applications for maximum benefit, thus avoiding the higher-pressure pipeline systems which are also connected to the gas interconnectors. As we indicated in our response to Q 1.c the impact on facilities will also be dependent on whether they are supplied by the "distribution" or "national distribution" network, so will vary from facility to facility.

[8] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1182228/DUKES_2023_Chapter_4_Gas.pdf

3. Do you have any comments on our views of the strategic role of blending, as described in this chapter? Please provide evidence to support your response.

We agree that the strategic role of blending is to support the growth of the hydrogen economy while supplies to alterative end users who need it to decarbonise are established. This also enables higher confidence for off-takers to switch to 100% hydrogen and helps an earlier transition for users at a lower cost.

However, we don't feel that Hydrogen blending into the Nat Gas system should be only used as a temporary measure to provide flexibility for future low carbon hydrogen producers focused on industrial decarbonisation (i.e., reserved offtaker). By providing a permanent outlet into sections of the NG network which can cope with up to 20%v of Hydrogen, the UK creates more stable demand which enable more de-risked low carbon hydrogen production projects to come online accelerating the development of market.

4. Do you agree that, if blending is enabled and commercially supported by government, the most appropriate mechanism would be via the Hydrogen Production Business Model? Please provide evidence to support your response.

We agree that if blending is enabled and commercially supported by government, then the most appropriate mechanism would be via the Hydrogen Production Business Models, but a small discount should be offered to the NG network operator on top, to incentivise the preferential use of H2 vs Nat Gas. If both are priced equally on a calorific basis, as established under the Low Carbon H2 Production Business Model, the Transport and Storage operators will have no incentive to choose H2 in place of NG, especially considering that some Capital Expenditure and may be Operational Expenditure (compression) may be required to inject the H2 into the NG network.

These models are already becoming well established (subject to approval in the Energy Bill) and understood by stakeholders including potential producers, the government and the government appointed counterparty to manage the relevant contracts.

We agree that this approach minimises the administrative burden, which is rising significantly with the introduction of RTFO, SAF mandates, DFD's for grid suppliers, etc. and other government initiatives.

5. Do you agree with the proposed lead option to allow both gas distribution network operators and gas shippers to purchase hydrogen produced for blending? Please provide evidence to support your response.

We agree with the proposal set out in the consultation that a flexible, hybrid, approach to allow gas distribution network operators and gas shippers to purchase hydrogen for blending is appropriate.

This is in line with established processes for conventional gas in the distribution system and creates a level playing field for participants.

6. Given blending's proposed strategic role as a reserve offtaker, do you agree that certificates for low carbon hydrogen injected into the gas network should be precluded from onward sale after the point of injection? Please provide evidence to support your response.

We do not agree that certificates for low carbon hydrogen injected into the gas network should be precluded from sale after the point of injection. The impact on Indirectly linked or dispersed sites with no physical connection to low carbon hydrogen should be considered.

Hydrogen sources may benefit in being able to purchase Low Carbon Hydrogen (LCH) certificates to offset against their UK ETS obligation. This would require a potential book and claim approach rather than a mass-balance one, with sufficient verification to ensure the scheme integrity (and in line with the LCHS). It could increase the uptake of the certification scheme, providing an additional value which does not appear to be available in the proposals.

This is particularly important as book and claim options allow a market to be made where physical product does not go. This allows less infrastructure to be installed, relative to the benefits obtained to a wider range of companies / users. BUT a book and claim system does require that the hydrogen blending is performed to a known concentration / spec as the subsequent analysis requirements for downstream accounting purposes would pose an unnecessary friction. (Metering alone is not adequate on a variable composition stream since the metered volume is used as a proxy for the calorific value obtained, which is no longer a valid assumption – as described.)

However, we agree that there is a potential risk of double counting in this matter; for example, if an emitter subject to the UK Emissions Trading Scheme (ETS) buys certificates to offset their obligation, their emissions and hence obligation would be calculated by the flue gas composition which is impacted by the natural gas composition. The emitter could then be claiming the benefit for emitting less CO_2 from the fuel that they burned, considering the CO_2 reduction from the hydrogen entering the gas distribution grid. This risk is being dependant on where the LCH goes into the grid relative to where the ETS facility pulls off the grid (and does not apply if the facility is completely segregated from the grid).

7. Do you agree with our lead option to adopt the free-market approach as the preferred technical delivery model for hydrogen blending, should blending be enabled by government? Please provide evidence to support your response.

We agree with the lead option being the free-market approach for the preferred technical delivery model for hydrogen blending.

This approach has been shown to work effectively to date for the management of the gas network and offers a level playing field for market participants. In particular implementation should not cause billing issues.

8. If your project is considering connecting to a gas distribution network for the purposes of hydrogen blending, where would that connection be (in terms of geographic region and/or pressure tier on the network)? Please provide an indicative timeframe for when you may want to connect.

Fuels Industry UK cannot comment on this question in detail.

9. Do you agree with our lead option to adopt Option A (working within existing frameworks) from the Future Billing Methodology Report as the preferred approach to gas billing, should blending be enabled by government? Please provide evidence to support your response.

We agree that Option A should be the preferred approach to gas billing to be enabled by government.

This uses the existing billing regulations, that are widely used and understood by participants in the UK market. We welcome the work that has been done in this area to understand the options.

Based on the information provided we note the limitations for hydrogen blending that the work established. We therefore ask that the Billing Methodology be reviewed if significant volumes of hydrogen are blended into the gas network to ensure that the Methodology remains fir for purpose, creates a level playing field and does not create any unintended consequences.

However, we would caution that the current billing methodologies would only work on a constant concentration of hydrogen within the gas being billed as there is only volumetric metering installed to date. If the hydrogen concentration is 20%v, this represents a 14% reduction in energy content of the volume metered, (as stated) relative to methane, which is an unacceptable difference. Therefore, blending really should be managed to either a small enough amount that it is marginal in terms of calorific value, or should be managed over long periods such that billing is performed accurately.

10. We welcome feedback on the economic analysis presented in this section and corresponding annex. Please provide evidence to support your response.

We have no significant comments on the economic analysis.

However, we agree with the comments regarding financing risk, particularly that blending could make some projects more investable by reducing volume risk.

The detail set out where hydrogen is blended into certain lower pressure sections of the GDN effectively at the pressure let-down points has particular technical advantages which probably outweigh other disadvantages. Mainly one of safety, as sections can be signed off as "hydrogen ready" a section at a time. But this requires some form of hydrogen header main to connect these locations to the hydrogen producers, thus mitigating geographical disadvantages for existing users and producers.

But simply using the GDN and blending as the buffer mechanism for control of hydrogen flows adds an unnecessary level of complexity to the gas main system as the composition would change. Any refiner or large user of waste gases will be fully aware of the limitations such constraints make upon equipment operation and the added complexity incurred.

Consequently, it is proposed that the GDN could be used for consumption of hydrogen via blending to a constant composition, but that it is not used as a short-term buffering option. Instead, a hydrogen grid, operating at an adequate pressure should be set-up connected to several major users of hydrogen such that existing hydrogen users/ producers which can act as the buffer instead. For example, if connected to refineries, chemical plants, glass plants, steel plants, hospital heating plants or other hydrogen producers/ consumers, these assets can use demand side management to balance the hydrogen system where the cost of dosing hydrogen themselves can be managed. Additionally, hydrogen storage (such as the Holford brine cavities) necessitate such a hydrogen main passing through Cheshire but large potential hydrogen consumers could more readily de-carbonize as a buffering mechanism, simply utilising the existing ETS as the balancing mechanism.

For the electricity grid, this is a clone of the much-used Short Term Operating Reserve (STOR) arrangement where larger users are incentivised to provide Demand Side Management (DSM) services. This is believed to be a much superior option than using the Gas Distribution Network (GDN) as a hydrogen dumping mechanism, simply due to the added complexity which this generates in managing the GDN.

It is realised that certain subsidies may need to be offered to ensure that the market cost of hydrogen and the ETS cost of CO2 are such that a policy failure does not occur (i.e., Hydrogen is too expensive) but to get a simple grid set-up and supplying customers and self-balancing – which can subsequently be expanded – is the most essential requirement.

In the UK, the ethylene pipeline system connects most major users; a copy of this is found in Figure 2 below. A similar arrangement could be installed (alongside in most sections) to provide a suitable system to manage demand. Clearly the more industrial sites connected the better, but there are at least 20 significant hydrogen users connectable to such a system, which should provide sufficient resilience to provide most of the daily DSM required while still allowing longer term swings to be managed by GDN blending.

Figure 2: UK Ethylene Distribution System [9]

[9] Petroineos supplied information.