National Transmission System Hydrogen Blending

Stakeholder Engagement Report

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Contents

Table of Acronyms

Acronym	Meaning
AACE	Association for the Advancement of Cost Engineering
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture & Storage
CHP	Combined Heat & Power
CNG	Compressed Natural Gas
CUSC	Connection and Use of System Code
DESNZ	Department for Energy Security & Net Zero
DEVEX	Development Expenditure
EU	European Union
FWACV	Flow Weighted Average Calorific Value
GB	Great Britain
GSMR	Gas Safety Management Regulations
HSE	Health & Safety Executive
H2	Hydrogen
H2P	Hydrogen-to-Power
ICF	Incomplete Combustion Factor
IEA	International Energy Agency
IETF	Industrial Site
OCGT	Open Cycle Gas Turbine
OEM	Original Equipment Manufacturer
OPEX	Operating Expenditure
LDZ	Local Distribution Zone

LNG	Liquefied Natural Gas
NG	Natural Gas
NGT	National Gas Transmission
NOx	Nitrogen Oxides
NTS	National Transmission System
NZIP	Net Zero Innovation Portfolio
PAS	Publicly Available Specification
PSA	Pressure Swing Adsorption
RD	Relative Density
R&D	Research & Development
SCGT	Simple Cycle Gas Turbine
SCR	Selective Catalyst Reduction
SI	Soot Index
SIF	Strategic Innovation Fund
SMR	Steam Methane Reformer
SO	System Operator
TRL	Technical Readiness Level
T&S	Transport & Storage
UK	United Kingdom

Executive Summary

Arup was appointed by the Department for Energy Security and Net Zero (DESNZ) to undertake a project to understand the potential impacts of hydrogen blending in the national transmission system (NTS) at blend percentages of up to 2%, 5% and 20%.

Approach

Our approach included:

- Literature review, to understand the current status of hydrogen blending in the UK and wider EU and who the key NTS end-users are.
- Stakeholder engagement in order to understand how NTS-connected sites could be impacted by receiving a hydrogen blend. This was done through the development of two surveys: one for the NTS-end users and one for the Original Equipment Manufacturer (OEMs). The survey captured responses regarding site details and potential technical and operational challenges with accepting a blend. It also focused on timelines and costs required to be blend ready, of blend impacts, deblending requirements and any previous studies completed. For the OEMs, the survey focused on the technologies offered, technical and operational challenges, research and development for hydrogen ready equipment and the support OEMs could provide to their customers in a transition to accepting a hydrogen blend. A workshop was also held with key stakeholders, including offtakers, lobby groups and other interested industry parties, to enable open discussion on survey questions.
- Review of the survey responses to identify the key impacts in terms of safety, operability, performance as well as challenges relating to accepting a hydrogen blend. From the stakeholder engagement, survey responses were received from 11 NTS-end users, representing 30 sites. One OEM also completed the survey, alongside email responses from two others. Responses were given a rating from 1 to 5 based on the site’s ability to accept a hydrogen blend at the blend percentages of 2%, 5% and 20%. The key challenges were identified across power generation, industrial and storage sites, as well as potential timeline estimates and costs required for sites to be hydrogen blend ready.

Key findings

Many challenges and concerns were raised across the survey responses, most notably regarding variability of blend, significant costs and timeframes to be blend ready, metering challenges and constraints on OEMs to deliver the required modifications at the same time. Overall, the responses suggest that while hydrogen blending, particularly at the lower percentage blends, could be technically feasible, there would be significant costs and downtime required and DESNZ should carefully consider if is worthwhile, as the UK rapidly develops 100% hydrogen infrastructure. Hydrogen blending is seen by respondents as a temporary solution that may have a negative impact on the consumer through resulting increased energy costs, or by reduced electricity grid capacity during the downtime required to install upgrades. Survey responses and analysis are covered in Section 3 and 4 respectively.

Section 1: Introduction

Background

Low-carbon hydrogen has been identified as a key solution for hard-to-electrify applications, including those in the industrial and heavy transport sectors, as well as a viable alternative to unabated natural gas for flexible power generation. To realise hydrogen's potential, timely development of suitable hydrogen transport and storage infrastructure between producers and offtakers is required to balance supply and demand, and to minimise future uncertainty for investors and wider industry. The deployment of hydrogen infrastructure to meet UK net zero targets may thus require transformational change to planning, regulation and governance of transmission and distribution networks, dependent on the expected scale and speed of hydrogen uptake.

The UK Government published the Hydrogen Transport and Storage (T&S) Networks Pathway in December 2023 [1], which lays out expectations for the development of hydrogen T&S infrastructure. In the early stages this will comprise small-scale networks, connecting co-located hydrogen production and demand, before regional networks are developed within and around industrial clusters. Regional networks may connect with each other in the longer term, leading ultimately to a core hydrogen network similar to the current National Transmission System (NTS) – the backbone of Britain's energy system today. However, the government views a core hydrogen network only as a possibility at this stage, whose existence is dependent on the overall development of the hydrogen market.

In December 2023, the previous Government set out a positive strategic policy decision that in certain circumstance there could be potential strategic and economic value in supporting the blending of up to 20% hydrogen by volume into GB gas distribution networks [2], pending the outcome of the safety assessment to be completed by the Health and Safety Executive (HSE) and any implications for the economic case. Hydrogen blending refers to the blending of low-carbon hydrogen with other gases, primarily natural gas and including biomethane, in pre-existing gas network infrastructure. It has been identified as a transitional solution to support early-stage hydrogen producers in a targeted way as it can reduce risk and cost at a project- or system-level, by enabling the co-utilisation of existing infrastructure until dedicated infrastructure is in place. Allowing for the delivery of hydrogen-natural gas (H2-NG) mixtures to offtakers could promote up to around 265,000 km [3] of existing distribution infrastructure in the UK as [2]:

- **An offtaker of last resort**: to help manage the risk of producers being unable to sell enough volumes of hydrogen to cover their costs (i.e. volume risk), providing an additional route to market whilst hydrogen transport and storage infrastructure and end user markets are developing.
- **A strategic enabler:** Enabling electrolytic hydrogen producers to locate to support the wider energy system in the initial absence of larger-scale hydrogen transport and storage infrastructure, i.e. locating behind electricity network constraints to enable the use of excess renewable electricity that would otherwise have been curtailed.

The strategic policy decision, however, pertained to blending into the GB gas distribution networks only, with a recognised need for Government to provide clarity to industry on transmission-level blending in the NTS, comprising approximately 7,600 km of high-pressure pipe across GB. Further considerations that will need to be evaluated as part of the economic and safety assessments for transmission-level blending include [2]:

- Impacts of blends and/or varying blend rates on industrial end users connected at the transmission level and the possible need for mitigations such as deblending, with associated costs.
- Developments across Europe, such as in relation to the EU Hydrogen and Gas Market Decarbonisation package, and any implications on international gas trading agreements.

The UK Government provided an update on timings for a transmission-level blending policy decision in 2024 signposting a consultation in early 2025.

Project aims and objectives

This study aims to support the upcoming policy decision as to whether to allow hydrogen to be blended into the National Transmission System (NTS) and, if so, at what blend % by volume. As part of the evidence-gathering work to support this decision, DESNZ is seeking to understand the potential safety and operability risks and impacts of different blends (2%, 5% and 20% of hydrogen by volume) and/or varying blend rates on large industrial users and potentially more sensitive power generators (e.g. CCGTs/OCGTs) connected to the gas transmission network. This aligns with the key challenge of end user sensitivity to blending, rather than the ability for the network to enable blending, and the need to establish a clear pathway for the adaptation of end-users to higher shares of hydrogen, minimising cost and logistical uncertainty.

The requirements of the assessment include:

1. Whether these NTS-connected users can accept variable hydrogen blends.
2. Whether there are safety, operability, performance, efficiency impacts and risks (e.g. for power generation, will blending impact production levels and therefore security of electricity supply).
3. Whether any modifications to equipment/processes or mitigations (e.g. deblending) are required and any associated costs (CAPEX, OPEX, DEVEX etc).
4. Timeline for industrial end users to be operationally ready to accept variable blends.

Further work is required to assess the impacts for up to 20% blends on industrial end users connected to the gas distribution network with a focus on gas fired power generators, but this report is focussed on NTS-connected end-users only.

Assessments will vary by site depending on the type of equipment used. Stakeholder engagement with a variety of NTS-connected end users and Original Equipment Manufacturers (OEMs) was undertaken to understand how their equipment would be affected by receiving a blend.

DESNZ's policy decision for transmission-level blending will be informed by this assessment. Other dependencies for a decision include:

- Drafting and circulation of a consultation and strategic policy decision
- Assessing the potential risks and impacts associated with the EU gas package; and
- A safety assessment to be completed by HSE following submission of the relevant safety evidence by National Gas.

Project scope

Blending must demonstrate economic and strategic value and align with the UK Government's overall strategic net zero ambitions. In this study, we assess the impact in terms safety, operability, performance and efficiency for NTS-connected end users to accept variable hydrogen blends. Through comprehensive stakeholder engagement, practical insights were obtained regarding the appetite and possibility of power generation, large industrial and storage sites to operate with 2%, 5% and 20% hydrogen blends, in addition to the capability of OEMs to supply end-users with the equipment required to enable hydrogen blending.

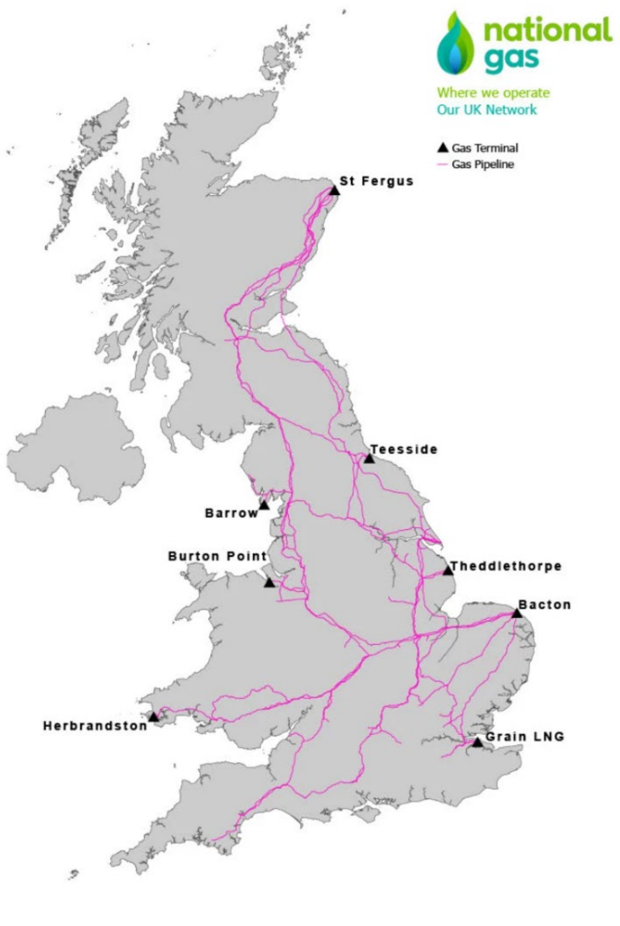
Initially, a literature review was undertaken, to identify the key NTS end-users and the current status of hydrogen blending in the UK and wider EU. Stakeholder engagement with identified key NTS-end users and OEMs was undertaken, to develop an understanding of how their sites could be impacted by receiving a hydrogen blend. The engagements were done through development of two surveys: one for the NTS-end users and one for the OEMs, and a workshop. The survey responses were analysed using a scoring system and key challenges identified. Survey responses and analysis are covered in Section 3 and 4 respectively.

Section 2: Literature review

Overview of the NTS

The UK National Transmission System (NTS) is the pipeline network used to transport natural gas throughout England, Scotland and Wales. It comprises approximately 7,600 km of high-pressure pipe and over 500 above-ground installations [4], including compressor, valve, metering, pigging, odorisation and pressure reduction stations. As shown in Figure 2-1, the NTS transports gas across the country from import gas terminals, which receive natural gas from several sources including offshore gas fields in the North Sea, large LNG tankers and direct pipeline interconnections with Norway, Belgium and the Netherlands. National Gas Transmission are the owner and System Operator (SO) of the NTS, considered to be a 'natural monopoly' regulated by Ofgem who simulate the effects of competition by setting price controls [5].

Figure 2-1: UK National Transmission System (NTS) pipelines with associated gas terminals [6]



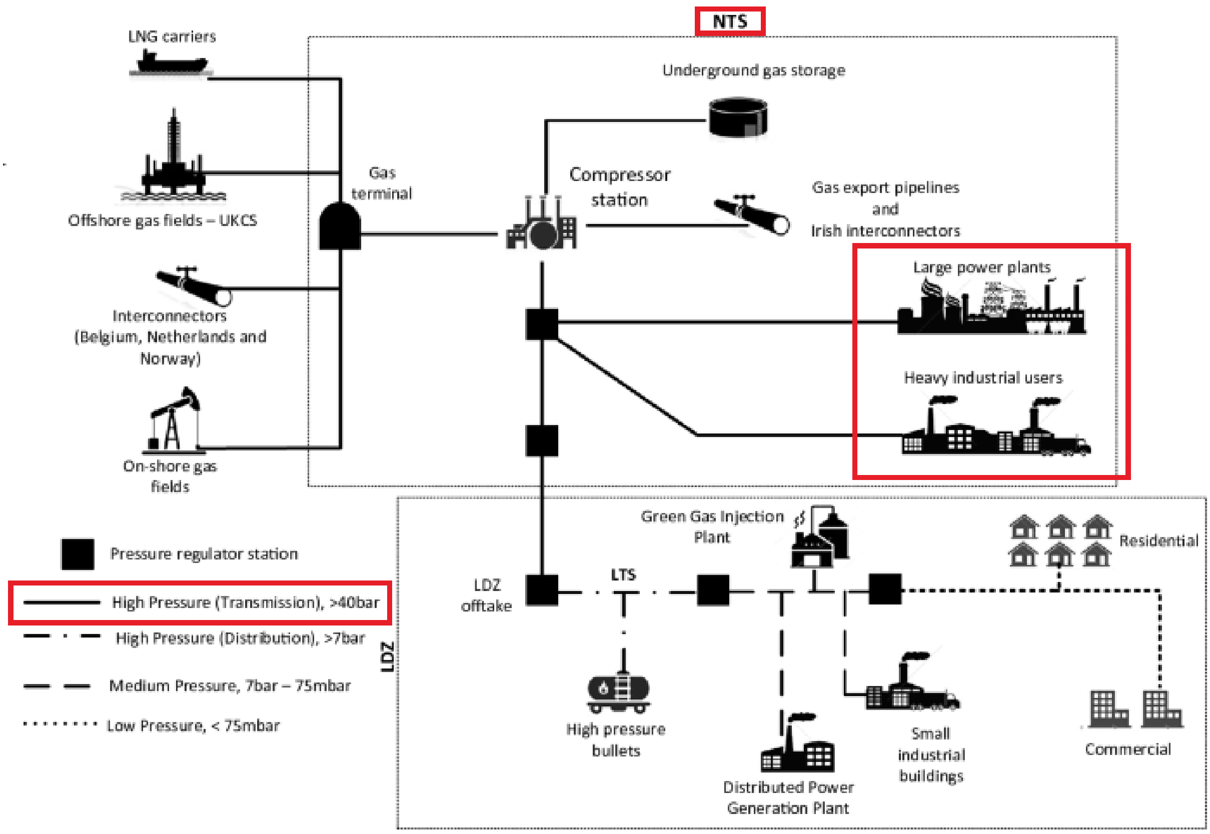
A map showing the GB National Transmission System (NTS) pipelines. The map also shows that NTS transports gas across the country from import gas terminals, which receive natural gas from several sources including offshore gas fields in the North Sea, large LNG tankers and direct pipeline interconnections with Norway, Belgium and the Netherlands.

NTS end users

As shown in Figure 2-2, the NTS is a high pressure (>40 bar) transport system for the supply of natural gas to:

- Local Distribution Zones (LDZs), comprising lower-pressure gas distribution networks that branch off from the NTS to supply commercial and industrial sites, and more than 80% of the UK's 28 million homes [7].
- End-users directly connected to the NTS, including power generators, large industrial users, underground gas storage sites and interconnector/gas export pipelines.

Figure 2-2: Schematic of current UK natural gas system with scope of hydrogen transmission-level blending study highlighted.



A diagram showing the full end-to-end structure of the GB gas system, highlighting in red where end-users of the gas transmission network (e.g. large power plants and heavy industrial users) sit within it.

End-users directly connected to the NTS are of particular interest in this study. A specific focus is placed on large industrial users and power generators that often require a consistent and/or high-volume supply of natural gas.

- Large industrial users: Facilities that use natural gas both as a feedstock and/or as a fuel for heating processes, including chemical plants, oil refineries, food and drink processing facilities, paper mills, pharmaceutical, steel and glass manufacturing sites. Volumes and demand profiles for each large industrial user can vary significantly, determined by the specific needs of the industrial process, with many users proactively seeking to fuel-switch to hydrogen as part of broader efforts to reduce carbon emissions. DESNZ has launched several key industrial fuel-switching competitions and funds in recent years to support the transition from fossil fuels to low-carbon alternatives including hydrogen. This includes the Industrial Fuel Switching Competition, Industrial Energy Transformation Fund (IETF) and Low Carbon Hydrogen Supply Competition [9].
- Power generators: Flexible power generation assets such as rapid-operating ‘peaker’ plants (generally Simple Cycle Gas Turbines (SCGTs) or gas engines) and larger-scale but less flexible Combined Cycle Gas Turbines (CCGTs), helping to meet short- and longer-term peaks in demand, respectively. The UK Government recently consulted (from 14 December 2023 to 22 February 2024) on the need and design for potential market intervention to accelerate the deployment of hydrogen-to-power (H2P) plants to potentially replace ageing natural gas assets [10]. This was followed by a government announcement, calling for the build out of new, gas-fired power stations to replace aging facilities, with mention of a change in law to ensure new plants can burn hydrogen or can be retrofitted with carbon capture and storage (CCS) technologies [11].

Current status of hydrogen blending in the UK

The UK Hydrogen Strategy, published in August 2021, highlighted the potentially significant role blending of hydrogen into the existing natural gas network could play in the development of the hydrogen economy, such as to facilitate access to a significant source of hydrogen demand for early low-carbon hydrogen producers (see Table 2-1) [12]. A key commitment was made by the UK Government to complete an indicative assessment of the value for money case for blending up to 20% hydrogen. The UK Government has since been working with regulators, industry and the HSE to assess the potential of up to 20% of hydrogen blending into the gas distribution and transmission networks, evaluating safety, technical, regulatory and commercial requirements. A strategic policy decision that in certain circumstances there could be potential strategic and economic value in supporting the blending of up to 20% hydrogen by volume into GB gas distribution networks was made in December 2023 [2].

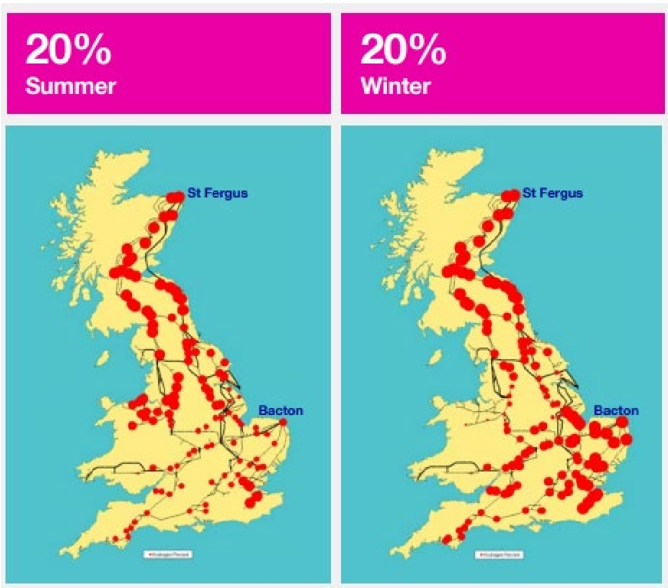
Table 2-1: Strategic role of blending to facilitate an early use case for hydrogen, as written in the UK Hydrogen Strategy (see 8.2 Appendix for the UK Government's five principles for delivering of hydrogen blending).

Strategic role	Potential benefits	Limitations and contingencies
Supporting low carbon hydrogen production & early development of hydrogen economy.	Blending could facilitate access to a significant source of demand for early low carbon hydrogen producers, potentially functioning as a useful sink for excess production (as an 'offtaker of last resort'). We recognise that blending could offer security for hydrogen production investment decisions, by providing a commercial option to sell hydrogen for gas consumer use.	As there are other 'demand offtakers' for hydrogen (such as in industry or power), depending on the blending value for money case, alternative offtakers might provide a preferable longer-term use for hydrogen.

National Gas issued a report in 2021 that used modelling of gas blending with injection points at St. Fergus and Bacton, to determine the penetration of the hydrogen gas into the network. The study showed that blended gas from St Fergus gas travels further into the network in summer when compared to the winter. The reason for this is due to the lower summer gas demands as shown in Figure 2-3. The graph has larger red dots for a higher concentration of hydrogen in the supply, with smaller dots showing a lower blend percentage. This is replicated for blends coming from Bacton, due to the export of gas from the UK to Belgium and the Netherlands in summer, which limits the penetration of blended gas from Bacton into the NTS. This indicates that it would be difficult to determine and guarantee the percentage of hydrogen blend to offtakers due to the complexity and variability of blend percentages received by the offtakers.

The report assesses the possibility of deblending being used as a means of allowing NTS connected offtakers to either guarantee a suitable percentage of hydrogen, or to remove the hydrogen altogether in the case their systems could not tolerate it. There is also the possibility of "reblending", where the deblended hydrogen is reinjected into the NTS, which would require new pipelines to be laid. The study outlined the difficulty of maintaining consistent hydrogen blends. This is because National Gas does not control the flow rate of natural gas supply at a terminal, which is instead determined by the market. Supply fluctuates over the year with higher supplies normally seen in the winter than in the summer, as well as a day-by-day variability. This study considers variations in the hydrogen production profile and hydrogen storage as two solutions to manage variability in demand.

Figure 2-3: Variability in penetration of hydrogen in the NTS between summer and winter [33]

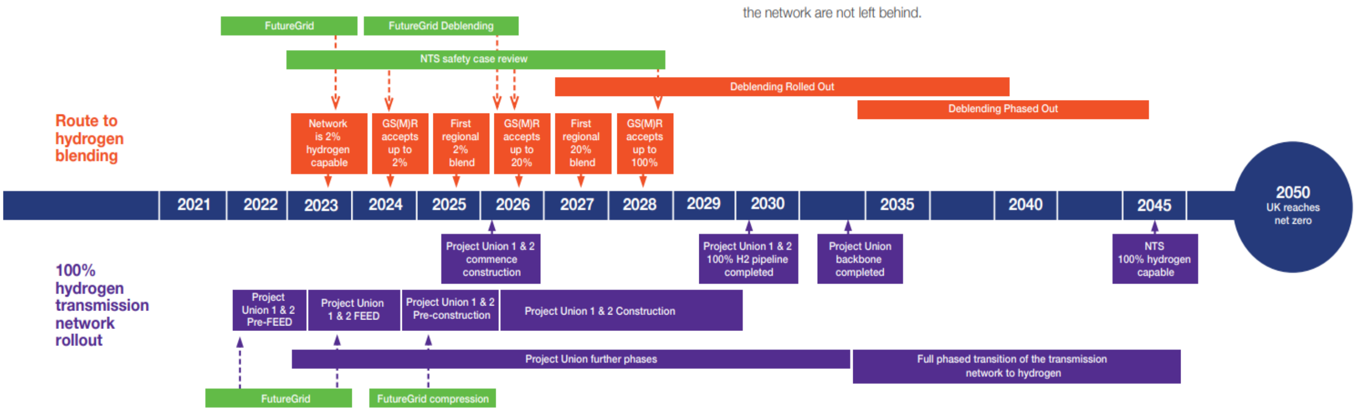


A UK map showing the variability in penetration of hydrogen in the NTS between summer and winter. The graph shows that blended gas from St. Fergus travels further in the summer, whereas it does not travel as far from Bacton in the summer.

Hydrogen blending as a potential interim measure alongside the development of a dedicated core hydrogen transmission network

The UK Government views blending as a transitional option as it relies on an extensive natural gas network being available to blend into, which is expected to reduce its capacity as the UK progresses towards net zero [2]. Nonetheless, utilising current pipelines and equipment in the short- to medium-term could reduce demand risk in a nascent hydrogen market, facilitate strategic planning and the safety case review of a core hydrogen pipeline network, and minimise uncertainty associated with the mass change-out of infrastructure ahead of demand. This is depicted in Figure 2-4 whereby regional 20% hydrogen blending was initially proposed for 2027 by National Gas, prior to the completion of the dedicated 'hydrogen backbone', Project Union, by repurposing 1,500km to 2,000km of existing gas transmission pipelines to support a low-carbon economy in the early 2030s [13]. In support of blending, many Original Equipment Manufacturers (OEMs) have reported that existing equipment should at least be capable of operating on a 20% blend [14]. Low-carbon hydrogen/blended gas is considered to be a relatively low disruptive option for fuel-switching of industrial sites when considering the use of existing assets (without the need of significant investment and therefore potentially resulting in a low-cost option) [15]. National Gas Transmission (NGT) was awarded funding for two Strategic Innovation Fund (SIF) projects by Ofgem to research the suitability of existing assets to transport hydrogen in the current NTS as part of the FutureGrid project [16] [17]. The FutureGrid project aimed to demonstrate that the UK's NTS can be safely repurposed to transport hydrogen by building an offline hydrogen test facility using decommissioned NTS assets.

Figure 2-4: Indicative timeline from a 2022 report of hydrogen blending with respect to 100% hydrogen transmission network rollout on the road to net zero in 2050 [13]



An indicative timeline produced by NGT in 2022 showing the interactions between the potential rollout of hydrogen blending and a 100% hydrogen transmission network.

The role of blending for large industrial users and power generators connected to the NTS

The current views of the UK Government (as of November 2024) for the role of blending for large industrial users and power generators are described below.

- **Large industrial users**: The UK Government is committed to the deployment of hydrogen as a solution for industrial fuel-switching (with a transitional role for hydrogen blending), with support provided from the £500 million Industrial Energy Transformation Fund (IETF) and various hydrogen end-use innovation programmes funded through the £1 billion Net Zero Innovation Portfolio (NZIP) [9]. The IETF allocates funding through three competition strands (studies, energy efficiency deployment, and decarbonisation deployment), with ‘Retrofits and upgrades of industrial equipment to use low carbon hydrogen or hydrogen blends’ included as a decarbonisation solution within the scope of the decarbonisation competition strand, alongside other solutions such as industrial electrification [18]. DESNZ is also sponsoring the British Standards Institute to develop a Publicly Available Specification (PAS) for hydrogen firing and conversion of large gas-fired equipment to support the standardisation of hydrogen-ready industrial boiler equipment, and have also sought evidence on how to support the decarbonisation of combined heat and power (CHP) equipment and hydrogen-ready industrial boilers [19].
- **Power generators**: As stated in the recent Hydrogen to Power market consultation report, published by DESNZ in December 2023, power plants could potentially utilise a blend of hydrogen with natural gas with onsite blending identified as a useful stepping stone for plants to eventually switch to 100% hydrogen firing [10]. DESNZ is intending to further assess the value of onsite blending in potentially supporting development towards 100% hydrogen firing, with several industry stakeholders reporting that power plants linked to clusters would be able to act as flexible offtakers due to their ability to take a variable volume of hydrogen to then blend onsite with natural gas prior to combustion. 100% hydrogen-firing generation equipment is estimated to have an approximately 10% cost difference to that of a comparable natural gas plant (i.e. a gas-fired OCGT compared to a hydrogen-fired OCGT), with the expectation that the CAPEX of all H2P plants will reduce as deployment progresses [20].

A summary of 54 sites directly connected to the NTS is provided in Table 2-2.

Table 2-2: Summary of 54 sites directly connected to the NTS, including storage/compression sites that are outside the scope of this study [21]

NTS Direct Connected Sites - 54		
Power Stations - 36 (66% by site count)	Industrial Sites - 9 (17% by site count)	Storage/ Compression - 9 (17% by site count)
CCGT Note 1 OCGT Note 2 Combined Heat & Power Reciprocating Engines	Oil Refining/ Petrochemical Glass Manufacturing Paper Manufacturing Chemicals Production Turbine Testing Facility	Natural Gas Storage CNG Re-fuelling Station

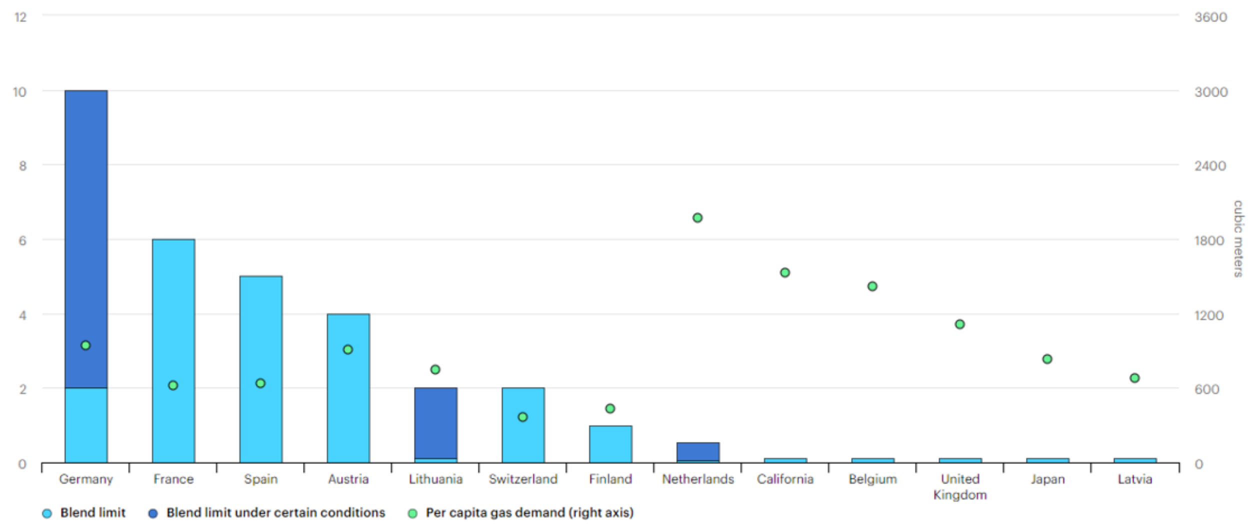
Table Notes

(1) Combined Cycle Gas Turbine (CCGT) – Turbine exhaust gases sent to Heat Recovery Steam Generator (HRSG) to raise additional steam and increase overall cycle efficiency.
(2) Open Cycle Gas Turbine (OCGT) – Turbine exhaust gases sent directly to stack, without heat recovery.

International review of gas network hydrogen blending

Current hydrogen blending regulations vary by country and are typically guided by the specifications of natural gas supply or the tolerance levels of the grid's most sensitive components. Historically, as shown in Figure 2-5, no more than 2% of hydrogen blending has been permitted in gas networks in many countries, with current directives of various countries permitting a hydrogen content in natural gas of around 0.1% to 10% by volume [22]. Blends of natural gas and hydrogen are already being used in several town gas networks in Singapore, Hong Kong and Hawaii, which plan to replace fossil-based hydrogen with low-emission hydrogen [23].

Figure 2-5: Limits on hydrogen blending in natural gas networks and gas demand per capita in selected countries (historical data as of Nov 2019) [22]



A chart showcasing, as of November 2019, the gas demand per capita in several countries and the limits on hydrogen blending in the gas networks. The chart shows that no more than 2% of hydrogen blending has been permitted in gas networks in many countries.

In the UK, current hydrogen content in the gas networks is limited to 0.1% by volume under the Gas Safety (Management) Regulations (GSMR) 1996; where a deliberate effort to safely blend new gases into the existing network requires evidence gathering and HSE approval, prior to any live deployment [24]. In contrast, Germany's Energy Industry Act (Energiewirtschaftsgesetz, EnWG) permits up to 10% hydrogen by volume to be blended into the natural gas network so long as no compressed natural gas filling station is connected to the network, in which case the limit drops to 2% [25].

The EU Hydrogen and Gas Market Decarbonisation package, a major legislative initiative published by the EU in December 2021 as part of the European Green Deal, also considers the role of blending as part of efforts to facilitate the integration of renewable and low-carbon gases into the existing gas network. This includes abolishing cross-border tariffs to facilitate trade of renewable and low-carbon gases, and harmonised rules on gas quality. As of March 2023, the legislation allows for the blending of hydrogen into the natural gas transmission system of up to 2% by volume from 1 October 2025, following a reduction by the European Council from up to 5% initially proposed by the European Commission [38] [39].

Recent transmission-level hydrogen blending developments in key countries are summarised in the following sub-sections. A focus is placed on countries in close geographic proximity to the UK given the importance of establishing trade relations with neighbouring countries within the emerging hydrogen market, including Germany, France and the Netherlands. It should be noted that establishing a clear, up-to-date understanding of key blending policy decisions proved challenging. This highlights the common delay in reaching final blending policy decisions across countries and the need for further in-depth review, particularly in relation to the EU Hydrogen and Gas Market Decarbonisation package and the impact of cross-border trading with neighbouring countries.

Germany

Similar to other jurisdictions, Germany’s legal and regulatory framework for hydrogen is not yet fully comprehensive. However, to support the gradual development of hydrogen infrastructure, the German Parliament passed an amendment to the Energy Act in July 2021 to introduce new provisions for regulating hydrogen networks as an interim measure until European guidelines are established [40]. Plans to incorporate these guidelines into German law are expected from 2025 onwards [41].

In terms of hydrogen blending, the German gas grid is well-developed and is believed to be capable of transporting up to 20% hydrogen without significant modifications to network infrastructure and end-user installations [42]. Gas distribution system operators have plans to do so gradually, starting in clusters, with several pilot projects investigating the impact of various blend levels on the network and end users. This includes the Erfstadt field test, involving a 9 km distribution network serving 100 households, which successfully began operating with a 20% hydrogen blend since October 2022 [43]. The German Technical and Scientific Association for Gas and Water (Deutscher Verein des Gas- und Wasserfaches, DVGW) has also been conducting studies to update technical standards related to the increased blending of hydrogen into the transmission network [44].

France

The French Government intends to use existing gas networks to transport hydrogen, with the transport network and natural gas distribution managers to be responsible for overseeing the injection of hydrogen in the national gas network [45]. The injection of hydrogen into networks is still at the research and development stage, however since the publication of the Law-Decree No 2021-167 of 17 February 2021 (creating a Book VIII in the Energy Code entitled “Provisions relating to hydrogen”, and extending the tasks of natural gas system operators to the injection of hydrogen), hydrogen produced in France can be blended with methane gas and injected into the existing natural gas networks [46]. Gas infrastructure operators and French Hydrogène, the hydrogen industry association in France, have recommended setting a target capacity of 10% blended hydrogen in the networks by 2030, increasing later to 20%, to enable clarity for operators to adapt their equipment, facilities and operating models and systems to achieve the target [47] [48].

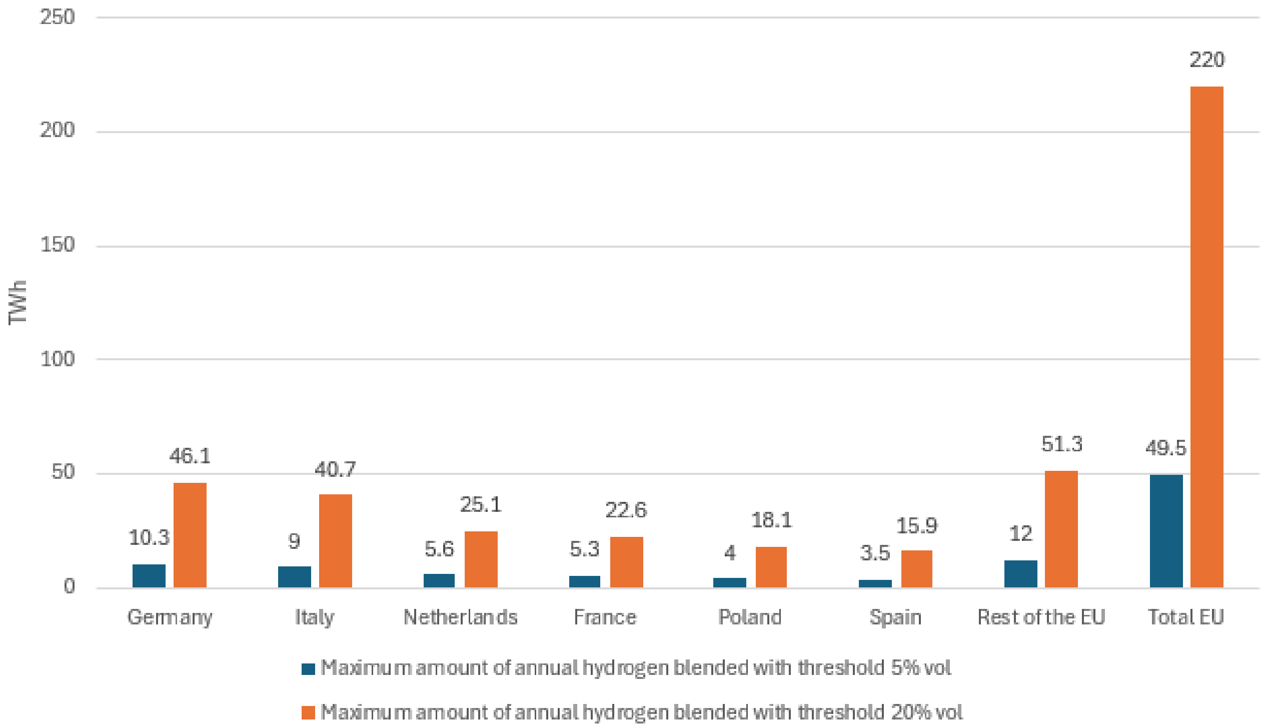
Netherlands

The Netherlands is viewed to be the first European country to be developing nation-wide hydrogen infrastructure, including the development of a ring-shaped national hydrogen pipeline to supply industrial clusters with 100% hydrogen [49]. As commissioned by the Dutch Government, this initiative is being developed by Dutch transmission system operator, Gasunie, with a total estimated cost of €1.5bn and 85% of the new network to consist of repurposed natural gas pipelines [50]. The Dutch Government and Gasunie are primarily focused on developing dedicated infrastructure for 100% hydrogen rather than extensive hydrogen blending with natural gas, with reasons related to the inefficiencies of blending (and subsequent separation) of pure hydrogen and natural gas, and the opportunity to utilise existing natural gas pipelines [50].

Summary of additional key transmission-level blending developments

A modelling assessment by the European Commission, published in January 2022, investigated the blending of hydrogen from electrolysis into the European gas grid [51]. The study simulated the inter-linkages between power and natural gas transmission networks, exploring the required electrolyser capacity for 5% and 20% maximum transmission-level blending limits for various countries in the EU. A summary of the maximum amount of hydrogen that could be annually blended into the transmission network used in the study is summarised in Figure 2-6.

Figure 2-6: Maximum amount of hydrogen that could be annually blended into the transmission networks of various EU countries as according to 5% and 20% thresholds for hydrogen blending.



A chart from a study commissioned by the EU showing the maximum volumes of hydrogen that could be potentially blended into EU Member States' gas networks at thresholds of 5% and 20% hydrogen by volume. The chart shows that a 5% threshold could allow up to 49.5 TWh of hydrogen to be blended across the EU, whereas a 20% threshold would allow up to 220 TWh.

Several transmission-level hydrogen blending projects, as described in the 2023 International Energy Agency (IEA) Global Hydrogen Review are outlined in Table 2-3.

Table 2-3: Summary of key international developments for hydrogen blending in national transmission networks, as identified in the IEA Global Hydrogen Review 2023 [23]

Location	Description	Source
European Union	In March 2023, the European Union altered the EU Gas Proposal, so that the maximum blending of hydrogen into the natural gas transmission system would be 2% instead of 5% to ensure a harmonised quality of gas.	[38]
United States	In May 2023, Xcel Energy awarded Worley a study to assess the feasibility of injecting blended hydrogen in its 58,000 km distribution pipelines and 3,500 km transmission pipelines, including the assessment of blended rates	[52]
China	In April 2023, China National Petroleum Corporation announced that it had transported blended hydrogen (24%) using a 397 km gas pipeline in Ningxia for 100 days	[53]
South Korea	In February 2023, Kogas selected DNV to assess the feasibility of blending hydrogen into the country's 5,000 km transmission network, as it aims to achieve 20% blending by 2026.	[54]
Portugal	In June 2023, REN announced that it had started adapting its high-pressure natural gas grid (1,375 km) to allow it to carry up to 10% hydrogen	[55]

Industrial end users that may require modification

Background

The most recent IEA infrastructure database [26] lists a total of 22 international projects blending volumes of hydrogen in the range from 1% to 20%. Many of these are demonstration projects on low pressure networks connected to domestic and commercial users, so not directly relevant to this study. However, these projects, including the UK HyDeploy project [27], have been invaluable in demonstrating the technical feasibility of safely using hydrogen blends in natural gas appliances. This report is only concerned with the users directly connected to the NTS, >40 bar, and so is focussed on the power sector and the subset of the industrial sector connected to the NTS.

Power Sector

Recent literature shows that there has been significant research and development by industry in recent years exploring the use of both hydrogen blends and 100% hydrogen in gas turbines [37] [56]. Modifications to the combustion technology are required at higher blending rates to deliver products conforming to the UK NOx emissions regulations. Typically, up to 10% volume of hydrogen in natural gas can be used without change but this will need to be confirmed with the vendor for each individual installation on the NTS, some of which are up to 30 years old. Blends above this 10% level may require modifications and it is expected that these will be relatively minor up to 20% blend levels, but this will need to be confirmed in each case. Each of the OEMs providing gas turbines to the NTS connected users offer retrofit solutions for using hydrogen blends and are developing products for very high blending rates as well as for 100% hydrogen [57] [58] [59]. Therefore, the expectation is that all the OEMs will be able to offer a solution to use the anticipated NTS hydrogen blending rates, but an engineering study will be required in each case to review the required changes to the gas turbine and ancillary equipment. These changes will be more substantial at higher blending rates.

A small number of direct connected NTS users utilise reciprocating gas engines. Demonstrations of operation at blends of up to 25% have taken place [60] [61], with similar engine efficiency. However, the results have shown increased NOx emissions which can be managed by Selective Catalyst Reduction (SCR) and engine tuning. Operating with hydrogen blends up to 20% is expected to be possible with little or no modifications, although an anti-knock protection system, if not present, may be needed. This will need to be confirmed with the OEM for each installation on the NTS.

Industrial Sector

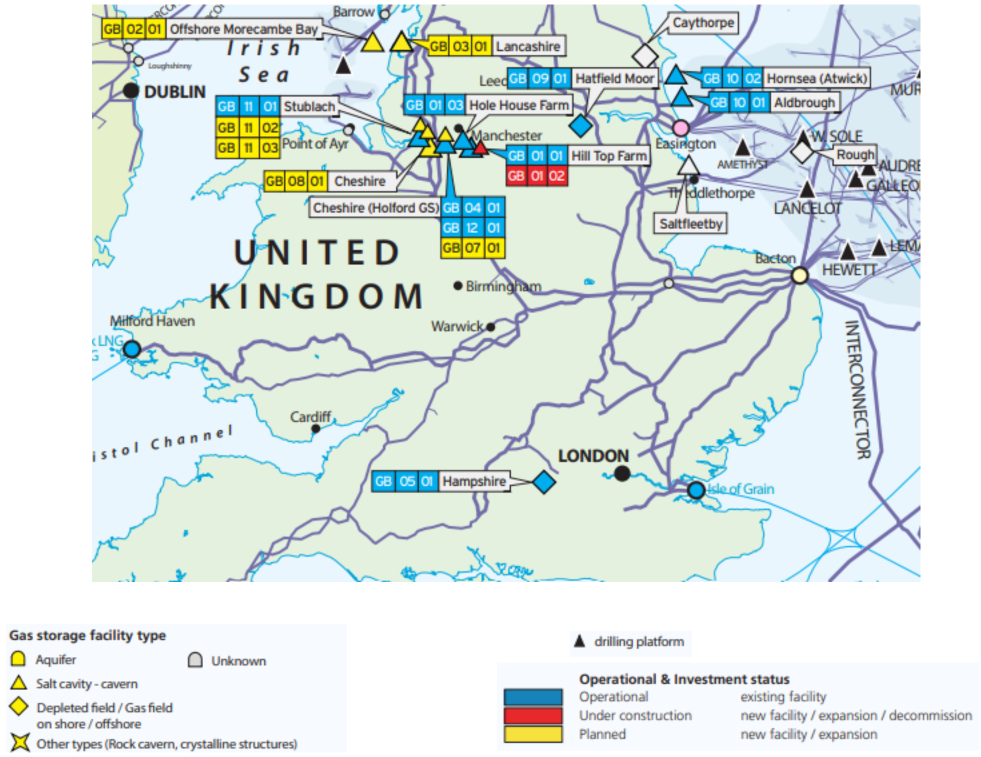
The industrial users directly attached to the NTS include refineries and petrochemical sites. Such sites typically have extensive experience in using hydrogen. Refineries have learned to harness high hydrogen content fuel in their boilers safely and efficiently. As their hydrogen supply is free, it helps these facilities save on fuel costs. Other industrial applications directly attached to the NTS include direct and indirect firing in the glass and paper industries. Direct firing in the glass industry has been successfully demonstrated with both hydrogen blends and 100% hydrogen retaining product quality [62] [63] [64]. Indirect firing using industrial boilers has also been demonstrated in a UK industrial environment [65], and a number of vendors now offer industrial boilers with 100% hydrogen or multi-fuel blend options [66] [67]. These references suggest that hydrogen blending up to 20% can be deployed but that each site will need to carefully consider NOx abatement measures, particularly at the higher blending rate. These may include modification to the burner operation, Flue Gas Recirculation (FGR), SCR or installation of low NOx burners. Furthermore, the impact on the product of the increased moisture content in the combustion products of a hydrogen blend, compared to natural gas, in direct firing needs to be considered.

It is worth noting that there are several Steam Methane Reformers (SMRs) directly attached to the NTS. As mentioned above for refinery and chemical industry applications we would expect such equipment to be able to manage hydrogen blends up to 20%. The hydrogen supplied to the NTS for blending will be low-carbon (green or blue) hydrogen, and the merits of using this to manufacture grey hydrogen will need to be carefully considered.

Storage

Also attached to the NTS are several gas storage facilities, which are vital to the operation of the gas transmission system, as shown below in Figure 2-7. Gas storage facilities act as a buffer to balance the supply and demand of gas, through storing gas when demand is low and releasing it again when demand is high, which provides stability to the market and reduces price volatility. Additionally, extra capacity provides security of supply and allows the pressure and flow within the network to remain stable during fluctuations in demand or when the network is being maintained [68] [69].

Figure 2-7: Storage network map in the UK based on 2018 GIE data [70]



A map showing the gas storage network of GB, with sites concentrated in the North West of England and in the North Sea, near Bacton.

The NTS-connected gas storage facilities mainly consist of salt caverns or depleted hydrocarbon reservoirs, except for the Avonmouth LNG terminal. Depleted hydrocarbon reservoirs are particularly vulnerable to the growth of subsurface microorganisms where there is a presence of hydrogen, which ultimately reduces the permeability and therefore storage capacity of the reservoir. Specific reservoir conditions are required to constrain the growth of these microorganisms, which are an important consideration to be made about the suitability of a depleted hydrocarbon reservoir for hydrogen storage. In salt caverns, the high-salinity environment reduces the likelihood of hydrogen conversion by microorganisms. There are currently existing salt cavern storage facilities for hydrogen in the UK, as well as in the USA and Germany. Given the practical impermeability of salt cavern structures, hydrogen storage in salt cavern is more likely to experience leakage through the caprock or wellhead, as well as from equipment that is common to most storage configurations, such as compressors, pumps and piping [31].

Another property of hydrogen which may result in required modifications to storage infrastructure is the lower energy density of hydrogen in comparison to natural gas [35]. This would potentially require additional storage to offset the reduced storage capacity in terms of energy.

Figure 2.8 shows the Technical Readiness Level (TRL) of various hydrogen storage technologies. Storage tanks and salt caverns are well-established for hydrogen, with depleted gas fields and aquifers yet to be proven technologies on commercial scale. The scale for the TRL is defined as per the International Energy Agency (IEA) definitions shown in Table 2-4 below.

Table 2-4: IEA TRL definitions [71]

TRL Level	Definition
11	Proof of stability reached
10	Integration needed at scale
9	Commercial operation in relevant environment
8	First of a kind commercial
7	Pre-commercial demonstration
6	Full prototype at scale
5	Large prototype
4	Early prototype
3	Concept needs validation
2	Application formulated
1	Initial idea

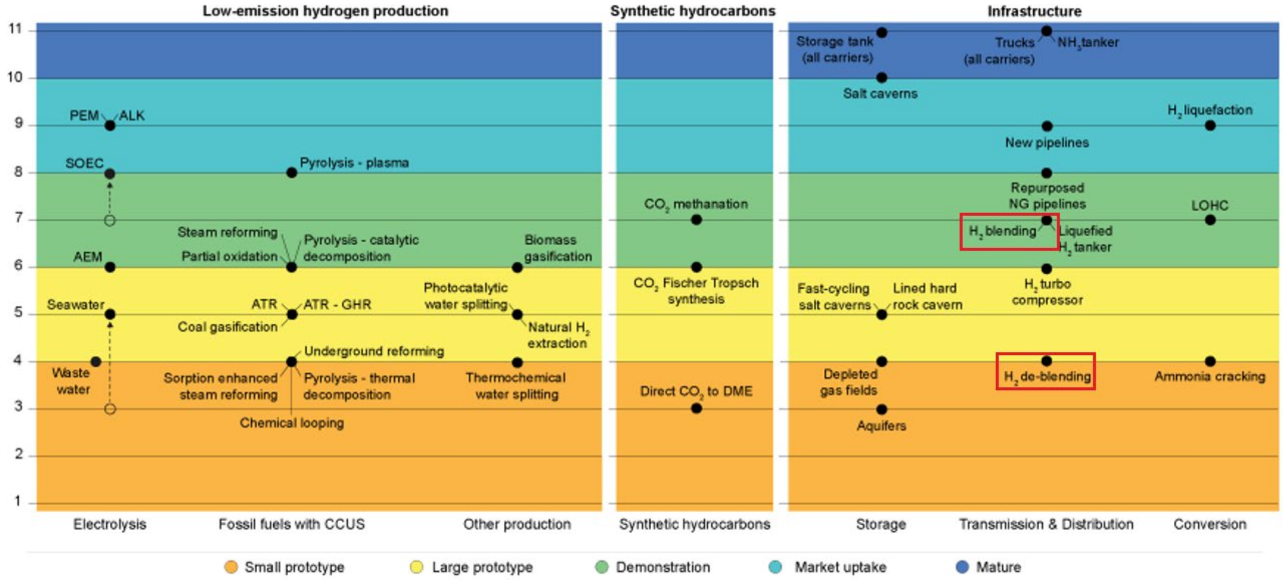
Deblending

Hydrogen deblending may be necessary for end users that require pure hydrogen or hydrogen-free natural gas separated from a blended hydrogen and natural gas stream. End users may consider this as an option to manage gas quality and hydrogen purity, especially when accepting greater shares of hydrogen by volume in the gas grid. For example, if the UK Government takes a positive transmission-level blending policy decision of up to 20% hydrogen by volume, deblending scenarios for end users may include:

- Some users may require pure hydrogen for dedicated uses, such as facilities that require hydrogen as a feedstock.
- Some hydrogen sensitive end users, such as existing power generation sites with legacy gas turbines, may opt for implementing on-site deblending to maintain a >98% natural gas feed as opposed to modifying or replacing existing technologies.

Used in industry for decades, mature deblending technologies include cryogenic separation, membrane separation and pressure swing adsorption (PSA) [23]. National Gas published a Hydrogen Deblending in the GB Network Feasibility Study in 2021, including a comprehensive review of each technology, noting that technology selection is influenced by process considerations such as feed gas flow, pressure, composition, hydrogen content and required hydrogen product purity and recovery [72]. An engineering study would thus be required to explore the suitability of deblending technologies for specific use cases and it should be noted that deblending technologies are not yet been proven on a large scale, such as in a distribution or transmission network, as reflected by a low TRL of 4 in Figure 2-8.

Figure 2-8: Technology readiness levels of production of low-emission hydrogen and synthetic fuels, and infrastructure [23]

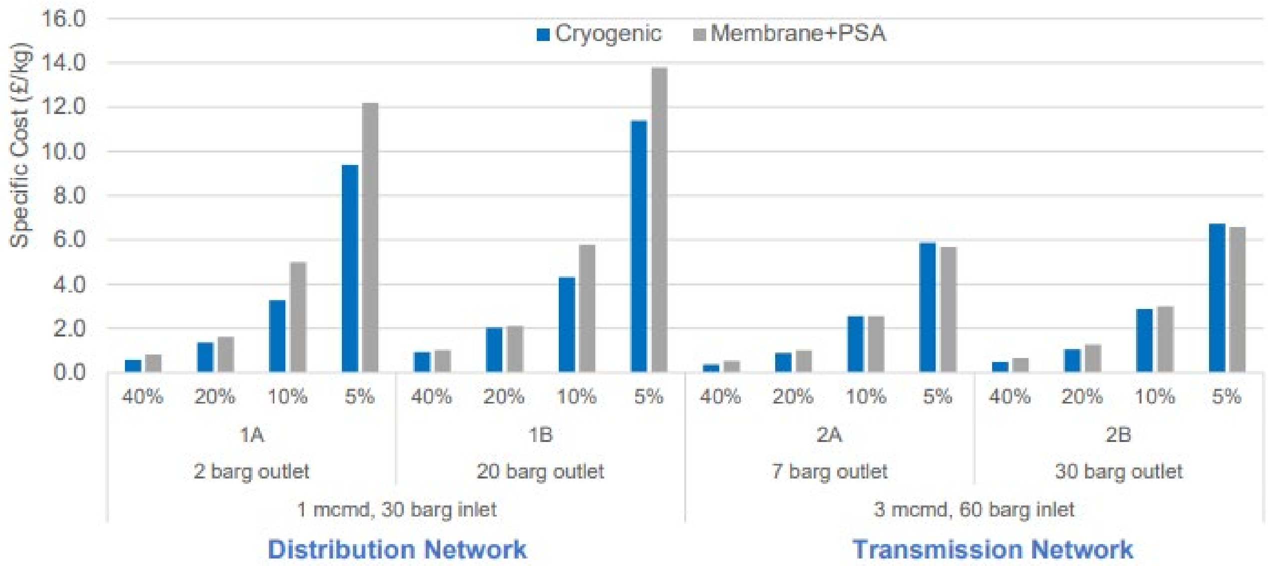


A chart showing the technology readiness levels of production of low-emission hydrogen and synthetic fuels, and infrastructure. It also shows that deblending technologies (rated a low TRL of 4) are not yet been proven on a large scale, such as in a distribution or transmission network.

Accurate deblending costs for transmission-level blending are not widely reported due to minimal deployment on a large scale, however literature estimates include:

- H2SITE estimates a cost range of 0.50 – 0.80 $/kg for hydrogen blends between 5% and 20% to obtain 99.97% hydrogen [73].
- National Grid (now National Gas) estimated cost ranges for a range of blends and pressures for several transmission and distribution network case studies when using cryogenic and combined membrane/PSA schemes, are shown in [72] Figure 2-9. Minimum specific costs of deblending for 20% hydrogen by volume are reported to be £1.0 - £1.6/kg for the membrane/PSA scheme and £0.9 - £1.4/kg for the cryogenic process [72].

Figure 2-9: Comparison of specific costs for hydrogen deblending using cryogenic vs. a combined membrane/PSA technologies [72].



A chart showcasing National Grid estimated cost ranges for a range of blends and pressures for several transmission and distribution network case studies when using cryogenic and combined membrane/PSA schemes. The chart shows that minimum specific costs of deblending for 20% hydrogen by volume are reported to be £1.0 - £1.6/kg for the membrane/PSA scheme and £0.9 - £1.4/kg for the cryogenic process.

Review of potential safety, operability, performance and efficiency impacts and risks of blending

Gas Characteristics of Blended Hydrogen

To understand the implications of fuel-switching from natural gas to hydrogen, Table 2-5 outlines the gas characteristics of natural gas; 2%, 5% and 20% blended mixes of hydrogen; and pure hydrogen. Key differences in chemical properties may impact the feasibility and requirements of large industrial and power generation end-users to adapt their existing processes.

Table 2-5: Approximate Gas characteristics of blended hydrogen, in comparison to natural gas and pure hydrogen.

Parameter	Natural gas	2% H2-NG blend	5% H2-NG blend	20% H2-NG blend	Pure hydrogen
Density (kg/Nm3)	0.71	0.70	0.69	0.65	0.0899
Wobbe Index (MJ/m3)	51	50.5	49.5 – 50.0	46.0 – 47.0	48.23
Flammability range (vol%)	5% – 15%	4.9% – 15.2%	4.8% – 15.4%	4.4% – 16%	4 – 75%
Ignition energy (mJ)	0.28	0.25	0.22	0.15	0.02
Burning velocity (m/s)	0.37	0.39	0.42	0.5	2.93
Adiabatic flame temperature (oC)	1,960	1,970	1,980	2,020	2,182
ATEX gas group	Group IIA	Group IIA	Group IIA	Group IIA	Group IIC

Safety

The safety implications of blended hydrogen networks have been considered in several safety studies and initiatives, including:

- *HyDeploy* – the approval of the 2019 project included an independent structured risk assessment process conducted by the UK's HSE. This included lab tests, pre-trial work, equipment specification review, and an extensive literature search of previous studies. The HyDeploy study required that before any hydrogen could be blended in the network, the HSE must be satisfied that the approved blended gas will be as safe to use as normal gas and that existing equipment and established procedures remain as effective in operating safely and managing the risks [28].
- *UK Gas Safety Regulations* – work has been carried out on the Gas Safety (Management) Regulations to make them hydrogen ready by removing some constraints such as Incomplete Combustion Factor (ICF) and Soot Index (SI) and replacing them with Relative Density (RD) limits. Other measurements of fuel quality were also replaced with RD, such as Nitrogen Content (PN), following a 2023 HSE consultation. The reason behind this is that RD is more applicable and future-proof to low-carbon fuels, and is already measured and telemetered at NTS entry points, meaning no action would be required by operators [29].
- *Centre for Hydrogen Safety* – created by the American Institute of Chemical Engineers and cosponsored by the U.S. Department of Energy, along with other national agencies, to create a global safety community and increase ease of access to material giving fundamental hydrogen safety training [30].

Key safety aspects & conclusions

In hydrogen gas pipelines, the likelihood and severity of explosion/fire can increase with higher hydrogen levels, due in part to the larger flammability range of hydrogen [30]. A US National Renewable Energy Laboratory (NREL) report concluded [31]:

- The likelihood and severity of explosion/fire can increase with higher hydrogen levels, due in part to the larger flammability range of hydrogen. At lower concentrations of hydrogen the failure frequency of pipelines due to materials issues or ignition events is largely unchanged.
- The addition of less than 20% hydrogen is not expected to increase the risk of explosion in the distribution system (lower pressure), in which risks are dominated by leakage.
- Due to the more rapid dispersion of hydrogen relative to natural gas, the safety risks associated with transmission pipeline explosions must be considered over a wider radius, and therefore are highly dependent on the population distributions near the pipeline.

The same NREL report [31] also highlighted that many of the safety risks are material-specific, depending on the choice of material in the gas network. Some materials are less tolerant of hydrogen than others, which can lead to degradation, embrittlement, or cracking. Some of the risks for some common hydrogen pipeline materials are shown in Table 2-6.

Table 2-6: Hydrogen pipeline material safety risks [31]

Material	Risks
Carbon and low-alloy steel piping	Alloys are susceptible to hydrogen embrittlement and fatigue crack growth due to low ductility and fluctuation of the operating pressures. Although carbon and low-alloy steels often are used in high-pressure transmission systems that require high strength, this group of materials would be susceptible to embrittlement and cracking from hydrogen-blended compressed natural gas (CNG), potentially even at relatively low pressures.
Ductile iron, cast and wrought iron and copper piping	These pipeline materials typically are used in low-pressure distribution systems and generally have not been of concern for hydrogen blend damage in distribution systems.
Stainless steel piping	Stainless steels are more ductile than carbon steels and might do well in low-pressure distribution systems for hydrogen blends. However, this group of alloys typically is not used in natural gas transmission due to higher cost.
Plastic piping	No major concern with hydrogen aging is expected for plastic piping, such as polyvinyl chloride, used in low-pressure distribution systems. However, diffusion of hydrogen in plastics is relatively high compared to that in alloys, which may present a higher safety risk
Polyethylene piping	No degradation has been reported with polyethylene piping used in low-pressure distribution systems. No adverse interaction is expected between hydrogen and polyethylene. However, diffusion of hydrogen in polyethylene is relatively high compared to that in alloys, which may present a safety risk.

The material risks in Table 2-6 above also apply to equipment in the gas networks such as compressors, regulators, valves, meters and detection equipment, as well as pipelines. Relative to natural gas, hydrogen has a greater tendency to leak through valves, gaskets, seals, and pipes, and risks associated with accumulation of hydrogen in confined spaces from those leaks could require additional monitoring/detection devices [31]. The above risks have also been highlighted in other reports which also suggest that safety concerns should be reviewed for equipment on a case-by-case basis [32]. HSE will also be performing a full safety assessment for both distribution and transmission-level blending. The narrative on the topic of safety in this section will not be conclusive.

Operability

National Grid (now National Gas) explored the operability of hydrogen blending in the NTS in a study published in 2021 [33]. This involved a theoretical analysis of the hydrogen penetration into the network based on two hydrogen injection points at St Fergus and Bacton. The study showed that there are varying blend percentages at offtaker locations, where the concentration decreases with distance from the injection point. There was also variability in concentration between summer and winter – the hydrogen tended to travel further in summer, due to lower overall demand on the NTS. This suggests that an operational challenge of hydrogen blending will be to manage the variations in hydrogen concentration for different offtakers. One potential way this could be solved is by deblending technology, which could enable customers who may be sensitive to gas quality fluctuations to receive a consistent hydrogen blend. Deblending is still being investigated in an industry study to determine the suitability of applying it to a national network, as it presents its own operational challenges, including the inability to re-inject the deblended hydrogen without repressurisation, which would add operational complexity cost.

Blending of hydrogen was researched and tested during the HyDeploy project which determined the technical feasibility of maintaining a maximum of 20% hydrogen at any moment in the system, avoiding perturbations in the flow, which would be potentially damaging to equipment. The result was the design and construction of the Grid Entry Unit which was supplied by Thyson Technology Ltd [74]. In 2021 this unit passed its Factory Acceptance Test. It controls the blending percentage by monitoring the incoming gas quality and flow of natural gas to analyse how much hydrogen can be added. Once the hydrogen is added, the gas is then analysed again to see if it is still within the specification of GSMR. In 2022, Honeywell also launched a hydrogen grid entry system, showing the emergence of this new technology in industry [75]. The Honeywell grid entry system is listed as containing the following functional parts:

- Hydrogen pressure reduction (if required)
- Hydrogen flow metering line
- Flow control system controlling the hydrogen flow
- Fast Gas Quality Measurement system of incoming natural gas
- Static blender for comingling of hydrogen and natural gas
- Gas quality measurement of blended gas
- Fire and gas detection
- Flow computer system
- Metering and blending control systems including remote terminal units / telemetry
- Cyber secure remote monitoring system

This suggests that the operation of the blending system may be complex, as well as purchase of this equipment coming at a large cost, especially for industrial scale hydrogen producers mixing the volumes of hydrogen that would be required for a 2%, 5% or 20% blend.

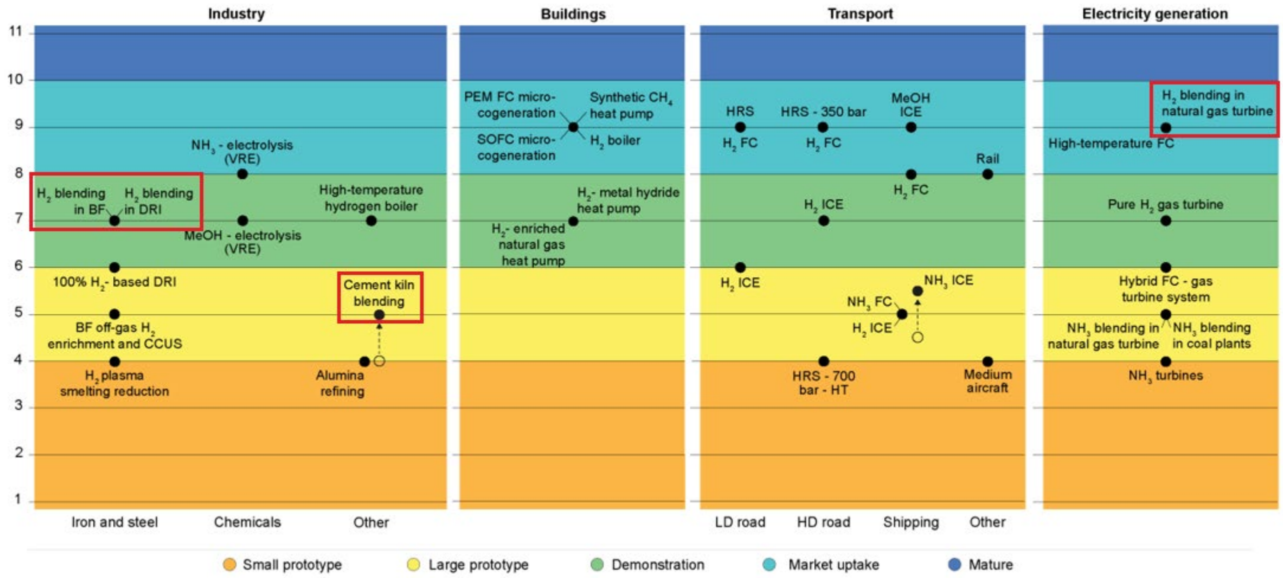
The operability of hydrogen blending is also varied depending on the nature of the offtaker. For water heaters which use hydrogen blending, studies have demonstrated that they appear to be more tolerant to higher concentrations of hydrogen, up to levels of 80-90%, as well as documenting studies on other equipment at blends of 20-30% [34], according to a 2023 report. This study does not comment on the durability or reliability and therefore does not advise this as a suitable upper limit, as it needs further testing.

Performance

A key characteristic of hydrogen combustion that will have an inherent impact on performance is that the heating value of hydrogen is one-third of that of natural gas by volume. This means that three times the amount of hydrogen fuel is used to generate the same power as the same amount of natural gas [35]. One mitigating factor of this is that approximately 20% less air by volume is required to produce a comparable flame with hydrogen to natural gas, which reduces the mass flow required through the combustor [36]. Hydrogen also has a broader flammability range, which can reduce the ignition delay time but also cause concerns for health, safety, and environment. Hydrogen flames have a higher flame temperature and speed but also have a lower emissivity than flames from natural gas combustion, which are counteracting effects on the performance of hydrogen in some applications.

The technology sectors with hard-to-abate emissions are developing slowly, resulting in a lower level of technical maturity, as shown in Figure 2-10.

Figure 2-10: Technology readiness levels of hydrogen end uses by sector [23]



A chart showcasing the technology readiness levels of hydrogen end uses by sector. The chart shows that the technology sectors with hard-to-abate emissions are developing slowly, resulting in a lower level of technical maturity.

Efficiency

As mentioned in above, the lower heating value of hydrogen will have an impact on the size of equipment required to generate power, which would make the facility less space efficient. The reduced power output will also result in a reduction in efficiency for all blend ratios.

It is believed based on the current classes of gas turbine technology available, that producing the hydrogen required to operate the large heavy-duty turbines, would require a large amount of power and water. This may be due to the current state of electrolyser technology which is bound to improve as the industry progresses and develops [37].

The overall impact on efficiency of offtakers' equipment will be investigated further as part of the stakeholder engagement phase.

Section 3: Stakeholder engagement

National Gas previous engagements

As part of evidence-gathering work to support the transmission-level blending policy decision, National Gas commissioned Progressive Energy to conduct a Hydrogen Acceptability Study for NTS connected sites, with a focus on assessing potential technical and safety impacts related to the adoption of hydrogen blending of up to 20% hydrogen [21]. The study categorised existing NTS connected sites into archetypes, and then identified potential constraints of transitioning to hydrogen blending for each archetype. The scope of this study was limited to potential technical and safety impacts and did not consider commercial viability of potential upgrades or the potential impact of equipment warranties.

The study concluded that generally most applications are capable of handling up to 20% hydrogen blends, however there is an expectation that modifications would be required, specifically for equipment such as burners or compressors. It was advised that safety assessments should be conducted case-by-case to identify site-specific risks and identify required mitigation. The study also identified that hazardous area classifications may not remain valid with hydrogen blending and would have to be re-evaluated, with potential increases in zone extents and ventilation requirements.

The next steps in the report highlighted the need for specific assessments in collaboration with equipment manufacturers and site engineers to understand safety, technical, environmental and economic impacts of transitioning to hydrogen blends, which is the aim of this study.

Stakeholder engagement approach

Arup have engaged with a range of stakeholders, including NTS end users (large industrial and power generation sites) and OEMs that supply such sites with equipment compatible for operation with hydrogen blends. Reponses to a series of questions, as detailed below, were collated to inform the evidence base and extend on the knowledge outlined in the literature review. The questions were developed with the intention of getting a complete a set of information in the responses as possible, with an introductory section outlining the context of the study for the stakeholders, aiming to maximise the response rate. The questionnaires were issued to all of the offtaker parties that Arup was able to acquire contact details for following NG’s engagement the NTS end users, with a 4-week requested time period to submit a response.

Stakeholders engaged include power stations, large industrial consumers and gas storage sites with key equipment including gas compressors, combined cycle gas turbines (CCGT), direct and indirect firing, and combined heat and power (CHP). An anonymised list of the stakeholders contacted is included in Appendix B.

End-user engagement

Table 3-1: Questions asked to NTS offtakers as part of end-user survey.

Category	Questions
Process overview and site conditions	What key infrastructure and technologies are currently in place at your site that use natural gas from the NTS (e.g. gas turbines, reciprocating engines, furnaces, boilers, etc.)? Please specify the below details for all relevant key equipment units. 1. How do you use natural gas from the NTS at your site? Please provide an overview of relevant processes. 2. Description of equipment 3. Gas reservation capacity (please specify units) 4. Equipment models and OEMs, year of installation and remaining life of equipment currently installed. Please give detail for each relevant unit.
Position on industrial fuel-switching, technical and operational challenges/ benefits.	What are your views on the following (at up to 2%, up to 5% and up to 20% blends)? 1. Technical challenges of hydrogen blending (specific to the equipment in your facility) 2. Operational challenges of hydrogen blending (e.g. performance, safety and efficiency) 3. Benefits and concerns with hydrogen blending (e.g. performance, safety and efficiency)
	Percentage of hydrogen volume received by NTS end users may fluctuate between 0% and the maximum blend percentage (2%, 5%, or 20%). Would any additional challenges arise from this? Please advise at what % blend these issues would occur.
	Would deblending (removal of hydrogen) or any other mitigation be necessary to integrate hydrogen blends into your existing systems, and at what blending % would this be required? Please outline any associated costs expected to implement deblending and/or other mitigations (if known).

Position on feasibility, timeline, and costs to accept hydrogen-blended gas at your site	What are your views on the following (at up to 2%, up to 5% and up to 20% blends)? 1. Have feasibility or pilot studies taken place to explore accepting blended gas at your site? Please provide details of any work completed. 2. What is your timeline to be operationally ready to accept blended gas? 3. What are the approximate associated costs to accept hydrogen blending at your site? Please provide details where possible, including the relevant AACE cost estimate classification for CAPEX).

OEM engagement

Table 3-2: Questions asked to OEMs as part of NTS end-user survey.

Category	Questions
Technology understanding and market development	What technologies (e.g. gas turbines, reciprocating engines, furnaces, boilers, etc.) does your organisation offer to NTS-connected industrial and/or power generation end users that can accept hydrogen blends (see Appendix 1 for list of relevant sites)? Please specify the below details for all relevant key equipment units. a. Type of technology, model type, capacity, efficiency, date of deployment at relevant site and hydrogen blend (vol%) capability. b. With reference to the equipment specified in (a), what feasibility or pilot studies you have conducted to prove operation up to 2%, 5% and/or 20% (vol%) hydrogen blends. c. With reference to the equipment specified in (a), can you provide case examples of commercial operation at up to 2%, 5% and/or 20% (vol%) hydrogen blends? d. For existing technologies already operating in the field at up to 2%, 5% and/or 20% (vol%) hydrogen blends, what modification(s) can you provide to enable operation with hydrogen blends. Please specify any associated downtime required for refitting. e. With reference to the modification(s) specified in (d), what are the additional CAPEX and OPEX costs associated with such requirements at up to 2%, 5% and/or 20% (vol%) hydrogen blends?

OEM views and support for hydrogen blending and R&D conducted	What are your views on the following? a. Technical challenges of hydrogen blending at up to 2%, 5% and/or 20% (vol%), including challenges to balance of plant, gas and fire detection, instrumentation compatibility, etc.? b. Operational challenges of hydrogen blending at up to 2%, 5% and/or 20% (vol%) (e.g. performance, safety and efficiency)? c. Benefits and concerns with hydrogen blending (e.g. performance, safety and efficiency).
	Are you conducting R&D to enable the acceptance of hydrogen blends for equipment at NTS-connected sites that are not yet hydrogen-ready? a. Please provide details of relevant R&D programmes for acceptance of hydrogen blending at up to 2%, 5% and/or 20% (vol%), being undertaken for specific equipment. b. With reference to the equipment specified in (a), please outline the current status of R&D and when you expect the equipment to be market ready.
	What support can you provide customers in the implementation, maintenance, and operation of technologies that accept hydrogen blends, i.e warrantees/guarantees, manufacturer maintenance/service agreements, training, technical assistance, etc.?

Interviews / Discussion

It was suggested by Energy UK that presenting the survey in a workshop presentation-style format may be beneficial to the study, by increasing engagement and allowing open discussion about the purpose of the study between the stakeholders. This meeting was held with stakeholders on 01/08/2024 via Microsoft Teams. The invite was extended by Energy UK to attendees including a mixture of offtakers and other interested industry parties and lobby groups.

The key points from the discussion are summarised as follows:

- Injection models are an important point to consider in the study, as highlighted in the literature review.
- Offtakers raised the point that it is not clear where the funding will come from for concept studies or pilot schemes with OEM’s, given that these would be significant pieces of work and require investment.
- There is an anxiety amongst end-users that blending will result in costs being incurred by them at some stage in the process.
- There may be an issue of OEM's capacity to carry out retrofitting / upgrading work to all sites at the same time, if a decision were to be made for hydrogen blending to go ahead – this is something that would have to be discussed with OEM’s and considered during the decision making.
- OEM’s market equipment units such as gas turbines as “Hydrogen Ready”, yet there is a gap between this and what OEM performance guarantees will cover, in terms of hydrogen blend %. End-users will not operate without a performance guarantee from the OEM, which means an open discussion must be held with OEM’s to understand how far away these are from being brought to market.
- It is not yet possible to properly test out hydrogen blending on a sufficiently large scale to prove it will work, due to the quantities of hydrogen that would be required for this.

Survey responses

Methodology

Ability to accept a hydrogen blend

All survey responses were collated in an Excel spreadsheet. Each site was given an overall score from 1 – 5 based on the site’s potential ability to accept a hydrogen blend. This scoring framework was applied to each site for each of the three blend percentages: 2%, 5% and 20%. The scoring framework is shown in Table 3-3:

Table 3-3: Scoring framework for each site response, based on the site ability to accept a hydrogen blend.

Site ability to accept a hydrogen blend	Score
Blending is possible at the current site, without modifications.	1
Blending is very likely to be possible, with some minor challenges/modifications.	2
Blending could be achieved, but with moderate modifications and challenges such as some limited downtime and/or costs.	3
Blending could be achieved, but with significant modifications and challenges such as prolonged downtime and/or high costs.	4
Blending could not be achieved.	5

Technical challenges

The responses were then reviewed with key challenges being identified. These could then be summed for each of the percentage blends, to display the number of sites anticipating each of the key challenges. The definitions for the key challenges are shown in Table 3-4:

Table 3-4: Definitions of the key challenge categories which were identified across the survey responses.

Key challenge category	Definition
Safety	Site safety implications, including but not limited to: hydrogen embrittlement, hydrogen leaks and risk to safe plant start-up and shut down.
Variability of blend	Variability of blend implications as a result of fluctuating hydrogen percentage in the blend, implications including but not limited to: rate of change of Wobbe number, impact to plant equipment such as control systems.
Significant costs	Significant CAPEX and/or DEVEX costs required, in the order of >£1M.
Increased emissions	Increased plant emissions, such as NOx.

Long lead time	Long lead time required for the site to be hydrogen blend ready, in the order of >1 month, due to staff training, equipment upgrade / replacement and down-time.
Reduced performance	Reduced equipment / plant equipment performance, including but not limited to: reduced power output and reduced efficiency.
Equipment upgrade / replacement	Equipment upgrades (e.g. control systems) and/or total equipment replacement required.

Survey results

The results from the survey responses are presented in this section. For further analysis of the results please refer to Section 4.

Out of the 26 survey requests, 11 NTS connected user responses were received, representing 30 sites. Of these sites, 24 sites were power generation, three were industrial and three were storage. One survey response was also received by an OEM. It should be noted that one of the sites has recently announced that it is set to close in 2025.

Power generation

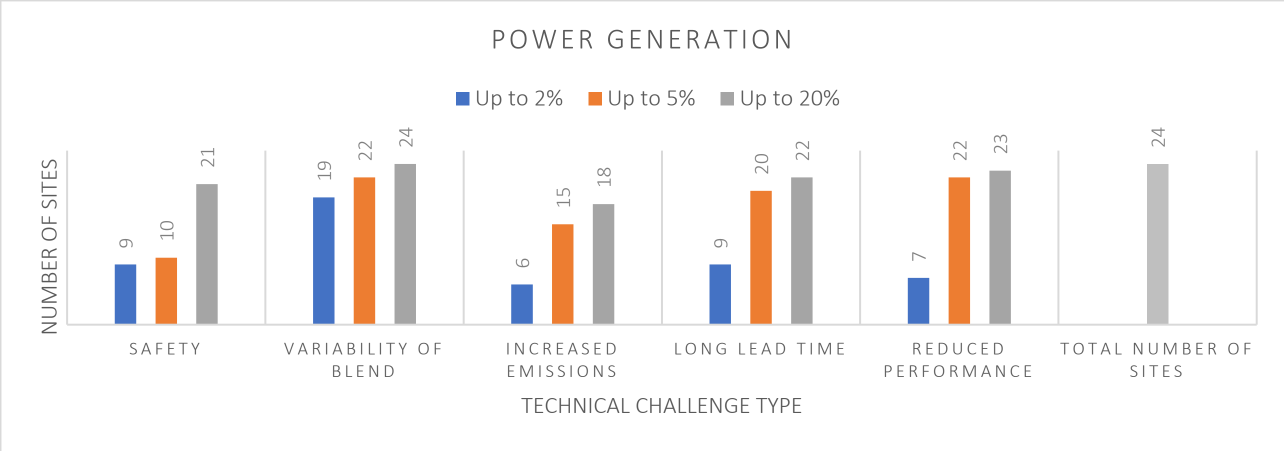
As shown in Table 3-5, out of the 24 power generation sites which responded, only one site has said that they could immediately accept a 2% hydrogen blend without any foreseen technical or operational challenges / modifications required. Four could accept a 2% blend with minor to moderate modifications. At the 5% scenario, only one site could immediately accept this, and one could accept with minor modifications. No sites could immediately accept a 20% hydrogen blend, and one could accept with moderate modifications. All other sites would require significant modifications, anticipating significant challenges.

Table 3-5: Table rating the ability of power generation sites to accept a hydrogen blend at 2%, 5% and 20% hydrogen blends.

Site Owner	No. of Sites	Archetype	Hydrogen Percentage		
			2%	5%	20%
Power generation owner 1	Single site	Reciprocating Engine	1	1	3
Power generation owner 2	Single site	Gas Turbine	2	2	4
Power generation owner 3	Multiple sites	Gas Turbine	2	4	4
Power generation owner 4	Multiple sites	Gas Turbine	2	4	4
Power generation owner 5	Single site	Gas Turbine	3	4	4
Power generation owner 6	Single site	Gas Turbine	4	4	4
Power generation owner 7	Multiple sites	Gas Turbine	4	4	4
Power generation owner 8	Multiple sites	Gas Turbine	4	4	4

Across these responses, multiple types of challenges were raised as concerns in accepting a hydrogen blend, as shown in Figure 3-1. The concern raised most frequently was variability of blend, with 19 sites identifying this as a concern even at the lowest percentage blend of 2%. This number increased to 22 sites for 5%, and all sites at the 20% blend scenario. Reduced gas turbine performance, (such as combustion instabilities, reduced power and efficiency) was raised by seven users at 2% blend scenario, increasing to 22 and 23 users at 5% and 20% respectively. Nine sites estimate long lead times to be ready to accept a 2% hydrogen blend, increasing to 20 and 22 sites anticipating long lead times for 5% and 2% respectively. Safety concerns were also raised in many responses, with 21 of 24 sites citing safety concerns at the maximum blend percentage of 20%. Furthermore, a significant number of sites (9 and 10) anticipate safety concerns even at the lower blend percentages of 2% and 5% respectively.

Figure 3-1: Graph showing the most frequently mentioned technical challenge types, and the corresponding number of power generation sites which mentioned these challenges.



A graph showing the most frequently mentioned technical challenge types, and the corresponding number of power generation sites which mentioned these challenges. The graph shows that across the survey's responses, multiple types of challenges were raised as concerns in accepting a hydrogen blend, including safety, variability of blend, increased emissions, long lead time and reduced performance.

Industrial sites

As shown in Table 3-6, none of the industrial site responses are able to accept a hydrogen blend either immediately or with minor modifications. One of the sites could not accept a hydrogen blend at any percentage, as their site would be rendered inoperable by the presence of hydrogen due to the composition requirements of their end product. Two sites could accept up to 2% hydrogen blend with moderate modifications. At the 5% hydrogen blend, one site could accept with moderate modifications and one with significant modifications. Only one site could accept a 20% hydrogen blend.

Table 3-6: Table rating the ability of industrial sites to accept a hydrogen blend at 2%, 5% and 20% hydrogen blends.

Site Owner	No. of Sites	Archetype	Hydrogen Percentage		
			2%	5%	20%
Industrial site owner 1	Single site	Gas Turbine + Indirect Firing + Chemical Feedstock	3	3	4
Industrial site owner 2	Single site	Direct Firing + Indirect Firing	3	4	5
Industrial site owner 3	Single site	Indirect Firing + Chemical Feedstock	5	5	5

Storage sites

Two storage site owners responded to the survey, representing three sites. As shown in Table 3-7, technical challenges are expected at all hydrogen blend percentages, with one site anticipating that hydrogen blend percentages at 5% and above would render the current asset design unsuitable and upgrades and/or asset replacement would be required. It is unknown whether a blend could be stored within the sub surface structure and whether this hydrogen would be consumed by bacteria present due to this storage facility being a depleted hydrocarbon reservoir. Whilst technical challenges at 2% blending may be limited, OEM technical assurance is still required and has not yet been provided due to lack of technical standards at this stage. One response highlighted that the reduction of storage capacity by volume through blending hydrogen with natural gas is a major concern, having potential significant impacts on security of gas supply and asset revenue. This challenge would evidently increase with increasing percentage of hydrogen in the blend.

Table 3-7: Table rating the ability of storage sites to accept a hydrogen blend at 2%, 5% and 20% hydrogen blends.

Site Owner	No. of Sites	Archetype	Hydrogen Percentage		
			2%	5%	20%
Storage site owner 1	Single site	Depleted Hydrocarbon Reservoir	3	4	4
Storage site owner 2	Multiple sites	Salt Cavern	4	4	4

OEMs (Original Equipment Manufacturers)

The stakeholder engagement survey for OEM's only returned one formal response from a reciprocating engine manufacturer. This manufacturer stated that up to 5% hydrogen blends there are no issues for their equipment; with no modifications required or challenges foreseen. They stated that for blends up to 20% hydrogen, a hydrogen blend signal would be required to notify the control system of the blend percentage and allow the ignition to be controlled appropriately. For engines older than 5 years, it was stated by the OEM that it may be necessary to upgrade the control systems to the latest software, which may require around 1 working week disruption if replacement of the system is required during a planned outage.

As well as the survey being completed by the OEM above, we also received two email responses from gas turbine manufacturers. One manufacturer suggested that all their current gas turbine models can handle up to 5% hydrogen blends, with higher blends likely to require an upgrade to combustion systems. As far as upgrades go for NTS-connected sites, they advised that the associated costs and schedule are very site specific and would require further investigation to get specific values of the cost including consideration of auxiliary piping, upgrade of combustors and associated controls, and potentially moving vent stacks to ensure ATEX compliance. Another respondent also produces gas turbines which are suitable for use with hydrogen blends, however they stated that studies to determine specific power plant conversion requirements would have to be procured at the request of the plant owners.

Section 4: Scenario analysis

Up to 2% Hydrogen blending scenario

13 out of the 30 sites who provided survey responses suggest that they could likely receive hydrogen blends of up to 2% with minor or no challenges/modifications. All of these 13 sites who held this view are power generation facilities. It is important to note that these sites still suggested they that they would require a consultation with OEMs to understand contractual issues associated with receiving hydrogen blends and provide technical assurance. However, even at the lowest percentage, the majority of users raised concerns that there may be an impact to their operations resulting from variability in the percentage of hydrogen they receive in their supply, where the percentage of hydrogen volume received may fluctuate between 0% and the maximum blend percentage (2%, 5%, or 20%). Firstly, variability in blend would have a potential negative impact on equipment performance and operation. The gas turbine combustion systems are sensitive to feed gas composition and so variability in this would have negative impacts on combustion stability and cause control problems, leading to decreased power output through de-rating and even equipment damage / outage. Furthermore, variability in blend would impact Wobbe Number. The allowable rate of change of the Wobbe index for a gas turbine based on OEM specifications is <0.1%/s, and it is believed this should be the case for streams containing hydrogen. This may not be achieved if there are significant fluctuations in blend percentage. It was suggested that there would need to be some form of early warning system from National Gas to advise the power plants of fluctuations in the blend being supplied to allow equipment to be tuned suitably for the fuel they receive. The CAPEX costs for this system would ultimately result in additional cost being borne by the consumers and recovered through increased energy prices.

Safety concerns were raised by nine sites, with the key risk being hydrogen embrittlement. Due to its smaller molecule size compared to natural gas, equipment materials may be susceptible to hydrogen embrittlement and leakage. It is therefore likely that even at the lowest blend percentage, mechanical integrity testing of existing equipment would be required. Several power generation users also raised the requirement for 100% (or very close to 100%) natural gas for safe start up and shut down of gas turbines. This would therefore be complicated by the presence of hydrogen as a pre-blended supply, as opposed to being site controlled. Six sites also noted increased emissions (specifically NOx) as a result of operating gas turbines on a hydrogen blend.

Many respondents highlighted that they do not currently have developed timelines to be hydrogen ready at this stage. For sites which provided timeline estimates, some anticipate that blending could be achieved as soon as OEM approval and confirmatory studies are provided. Others anticipate that ~2 years is required to allow for detailed studies and any equipment upgrades which may be required, as well as potential employee equipment and safety training. The survey responses provided very limited estimates for the costs required to be hydrogen blend ready, due to lack of OEM technical assurance and uncertainty on what modifications may be required in the absence of detailed studies. One power generation site owner estimates that feasibility studies alone could cost ~£1 million and take between 12 to 18 months. Another estimates that to enable a 2% hydrogen blend, the costs for required control system upgrades could be in the region of £10-15 million.

For the storage sites, the key challenge with accepting a hydrogen blend is a reduction in effective capacity. Natural gas with blended hydrogen has a lower calorific value than natural gas alone, and through blending the effective capacity of the gas storage assets in terms of energy is reduced. One storage site owner provided estimates for the reduction in energy density at the three hydrogen blend percentages, showing that the significance of this challenge increases with increased hydrogen percentage. Their estimates show a 3% reduction in energy density (per m3) when using a 5% hydrogen blend, rising to a 24% reduction in energy density at a 20% hydrogen blend.

The capacity of natural gas storage assets is tailored for the UK market, and so blended hydrogen even at low percentages could have negative impacts on security of supply, though the extent of this is unclear at this stage. This reduction in storage capacity also raises cost implications, due to a reduction in income from the storage assets. No estimates for the potential costs required were given by the storage site responses. As raised by one storage site owner it is unclear what modifications are required at this stage due to lack of FEED studies to date, however they anticipate that the reduction in revenue alongside DEVEX, OPEX and CAPEX spend could result in storage asset closures if support is not provided. The responses highlight that a commercial market or government support would be required to provide a longer-term business case to justify the spends required.

Up to 5% Hydrogen blending scenario

For the up to 5% hydrogen blending scenario, 27 of the 30 sites that responded believe that significant modifications would be required with prolonged downtime and/or high costs to allow them to accept blends of up to 20%. One site stated that under their long-term service agreement with their OEM, they can operate up to a 5% blend of hydrogen, however it should be noted that this is because their turbine is relatively new when compared to the other sites (installed 2016). The other site that stated that they could immediately accept a hydrogen blend up to 5% has reciprocating engines which were installed in 2020.

22 of 24 power generation site responses highlighted reduced turbine operability as a key challenge in accepting a 5% blend, such as decreased power output, combustion instabilities and lower efficiency. Variability of blend was also raised as a major concern by these sites, with the additional variability increasing the risk of problems such as combustion instabilities and possible flashback. The same safety considerations regarding safe startup/shutdown and hydrogen embrittlement and leaks apply to the 5% blending scenario, but with higher risks. 15 of 24 power generation sites also mentioned increased NOx emissions, potentially raising issues with environmental permitting.

In order for sites to be hydrogen-ready, costs and lead times will vary depending on the extent of the equipment upgrades / replacement required. 20 out of 30 site responses estimate that the long lead times would be required to be ready to accept a 5% hydrogen blend. Most sites which provided an estimate for lead times were in the order of approximately three years and longer. One site estimates that 1-2 years would be required for assessment, and following this any necessary equipment upgrades would be undertaken during planned gas turbine major modification which generally occurs every 3-4 years, giving a total lead time of 4-6 years. It is important to note that many responses highlighted OEM capacity as a crucial factor in estimating lead times. One response also states that OEMs are quoting lead times of up to 24 months for standard components. This therefore becomes an even more significant factor when considering multiple NTS connected users requiring OEM assessments and/or equipment upgrades simultaneously, if a hydrogen blend is introduced.

Of the storage sites, one stated that 5% blending and above would provide substantial technical challenges and likely require significant modification & replacement of surface assets, as their storage asset in its current design is not suitable. As discussed, the challenge regarding the reduction in storage capacity (and hence reduction in asset income) also applies to the other percentage categories. It is important to note that the higher percentage hydrogen blend, the more significant the challenges are, and so higher hydrogen blends would result in directly impacting the storage asset’s ability to deliver energy into the gas system. This could have significant implications in ensuring security of supply, particularly during winter months when demand is highest.

Up to 20% Hydrogen blending scenario

For the up to 20% hydrogen blending scenario, 29 of the 30 responding facilities believe that significant modifications would be required with prolonged downtime and/or high costs to allow them to accept blends of up to 20%. 24 of the 24 power generation facilities who responded to the survey see the variability of the blend being a key technical challenge, with 22 of the 24 facilities highlighting safety issues and a long lead time of procuring the required equipment as barriers in accepting the blended gas. For such significant implications to be foreseen across the board for power generators, this suggests a period of transition to up to 20% hydrogen blending may be long, complicated and at substantial financial cost.

If this scenario were to be considered more seriously, given that the power generators believe they will experience prolonged downtime, the impact to the energy security of the UK would have to be analysed in greater detail. This could be done by looking at whether the grid could support the power demands of consumers in a period where any one of the power generators would be taken offline for the time taken to install and commission any infrastructure and equipment modifications that would be necessary for up to 20% blending. A situation where blackouts occur must be avoided, due to the impacts on the economy and the public perception of the energy transition, which may be damaging to the support for cleaner energy solutions.

Of the industrial sites that responded to the survey, two of the three stated that they would not be able to accept up to 20% hydrogen blends, leaving the plant inoperable. One production facility anticipates an OPEX of the equivalent of at least 20 p/therm increase as a result of the deblending equipment that would be needed to ensure <0.1%wt hydrogen. Given the existing pressures from high energy prices in the UK the business would not be able to tolerate this increased cost, and production would be shifted to an overseas asset. Another site believes they are unable to tolerate either hydrogen blending or the costs of deblending – if support is not provided to mitigate the impact of hydrogen blending it is likely their site would be closed with the loss of >250 jobs. Another user stated that the company needs to be protected from the additional costs associated with being supplied with a hydrogen blend to ensure that they can compete internationally. As stated in Section 2, estimates for the minimum specific costs of deblending for 20% hydrogen by volume are reported to be £1.0 - £1.6/kg for the membrane/PSA scheme and £0.9 - £1.4/kg for the cryogenic process [72]. Based on these published values, Appendix C shows some estimates of what the cost of deblending 20% hydrogen may be for offtakers, based on survey responses that included gas usage.

All of the three storage facilities that responded to the survey stated that there would be a long lead time for the required equipment upgrades to accept up to 20% hydrogen blends, which would result in a significant outage period that may threaten energy security. As well as the significant costs expected, there would also be a reduction in the storage capacity of the assets, which would reduce the income of each facility and may mean that additional storage assets would be required to give the UK the same storage capacity in terms of energy. To further assess the expected safety issues, mechanical integrity testing would be required on each storage asset, given the nascency of blended gas storage technology.

Section 5: Conclusions

There are significant costs of implementing hydrogen blending in NTS

A common problem between the feedback we received as part of this study and the outcome of the literature review is the lower volumetric energy density of hydrogen, which results in a lower energy density for a hydrogen blend compared to 100% natural gas. Overall, the feedback received on specific costs was limited – most sites will require an engineering study before producing estimates and that these will take time to confirm what needs to be upgraded. These studies would require funding if blending was being seriously considered and will require further OEM engagement. Furthermore, any equipment modifications or replacements would result in further costs. Finally, due to the lower energy density of hydrogen, the current scale of gas storage may not be sufficient to meet energy demand requirements in the UK. Further investigation should be done into the implications for storage operators.

Metering of hydrogen-blended gas is a complex issue

Due to the locations of hydrogen production, it is possible that some locations in the NTS may receive very low concentrations of hydrogen. For purposes of safety and contingency, these locations would likely need to make the modifications anyway, which would require a potentially unnecessary capital investment. The Gas Billing regulations would protect offtakers to ensure that the minimum calorific value of gas injected cannot reduce the Flow Weighted Average Calorific Value (FWACV) which users are billed by more than 1MJ/M3, for each charging area. However, this would mean metering would be required for each charging area to measure the hydrogen injected in that area and determine the FWACV, which may differ between different billing areas based on hydrogen injection points. Additionally, there may be effects on the capacity market if some plants are not physically connected to a blended hydrogen network due to distance, and some are. CCGT facilities in different charging areas may be competing to offer electrical grid services if hydrogen is blended at a location in between the two sites. This may mean that the FWACV of blended gas would be below the allowable limit for one charging zone and not another, complicating the metering of the gas sold.

Blend variability will cause issues for offtakers

A consistent concern throughout the survey responses was the issues that would be caused by fluctuations in the percentage of hydrogen blended into the network, which is something that would be near-impossible to prevent. This was discussed in detail in the National Grid (now National Gas) report reviewing penetration of hydrogen into the NTS and the variability between locations [33]. Multiple injection points would be required to better control the variability of blend percentages as well as potential infrastructure upgrades and downtime for power generators as well as controlling the rate of change in any concentration of hydrogen to avoid any implications of significant inconsistencies in the hydrogen blend percentage. For industrial offtakers, there may be a negative impact on their product quality at higher blend rates (e.g. Goole), which would need time to evaluate and mitigate. For industrial users manufacturing products such as syngas (CO), deblending would be required and therefore could potentially make the site uneconomical.

OEMs would struggle to install required modifications at the same time

A concern raised by some stakeholders was the enormous challenge of preparing all NTS users for blending at the same time. It is important to recognise that whilst there are several sites which anticipate that a 2% hydrogen blend could be accepted without significant modifications being required, this is still dependent on detailed reviews on the full impact in terms of performance, safety and technical considerations. These reviews would also include fuel systems and control & protection suitability for blends and would be required for all NTS connected users, therefore requiring significant costs and time. As well as it being unlikely that OEM's would be able to support upgrades taking place to all NTS-connected sites simultaneously due to their own available working capacity, it will potentially create an energy security issue if significant numbers of power generators are offline for upgrades at the same time. This was discussed in contrast to blending on the distribution system where sections of the grid can be used to deploy blending, reducing the number of stakeholders required to adjust their equipment. The limited survey responses from OEM's reinforces the point that there is a funding gap in the investigation of hydrogen blending, which will only be driven by policy.

Blending may not be an enduring solution

One offtaker suggested that blending was not an enduring solution. The existing NTS could be repurposed for 100% hydrogen and existing pipework between industrial clusters could be used, rather than diverting complex engineering work and effort, as well as significant cost into a blending approach, which has significant implications.

One site operator questioned whether they were under any obligation (via NGT / CUSC) to have considered the implications of hydrogen blending. They saw an advantage in looking at moving to 100% hydrogen rather than a variable blend, and believed a considerable amount of further work was required on an Impact Assessment to inform any future policy decision.

All of the above reasons suggest that while hydrogen blending in the NTS may be technically feasible, there would be significant costs and downtime for the NTS-connected sites contacted in the survey,. It should be carefully considered if the level of disruption required to implement hydrogen blending is worthwhile, as the UK rapidly develops 100% hydrogen infrastructure. One power generation facility who responded to the survey believes that blending may result in the costs being recovered through the capacity market. Another power generation facility response also believes that some of the CAPEX costs required for sites to be able to accept a blend would have to be borne by the gas customers.

It should also be noted that the impact of blending on the distributed networks from the NTS, such as the LTS and lower pressure tiers, has not been considered in the scope of this study. It is expected that similar concerns may be shared by these offtakers as those with the NTS.

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[80] European Commission, “Hydrogen and decarbonised gas market package”.

Appendix A

UK Hydrogen Strategy – five principles for delivery of hydrogen blending

The UK Government outlined five principles for the delivery of hydrogen blending in the UK Hydrogen Strategy, highlighting the need for collective evidence gathering with Ofgem, the gas networks and wider industry. This was supported by five set actions to develop the safety case, technical and value for money assessments for blending of up to 20% hydrogen (by volume) into the existing gas network [12].

Government recognises that, should blending be rolled out, industry will need early sight of how it should be implemented. We are proposing five principles for delivery:

- Blending low carbon hydrogen across the existing gas network, or parts thereof, would remain within safe limits set by the HSE (likely up to 20 per cent by volume); and any proposed changes to gas quality and infrastructure would meet all safety requirements.
- Any proposed changes to gas quality and infrastructure should maintain existing system, pipeline, and consumer appliance operability.
- Blending should not prohibit a secure supply of gas for consumers.
- Any costs to consumers should be affordable (ensuring value for money).
- Blending could support initial development of the low carbon hydrogen economy, but blending is not a preferred long term offtaker.

Government, Ofgem, existing gas networks and wider industry must continue to share information and work closely on evidence gathering and aligning understanding on safety, physical roll out models and value for money. Forthcoming actions range from:

- Addressing safety, operability and technical concerns.
- Proposing an optimal, practical model for blending.
- Conducting a value for money assessment.
- Comparing the merit of blending versus other end uses for low carbon hydrogen.
- Creating a regulatory and commercial framework, for example – a new billing methodology.

This is essential work that we will prioritise in the coming years.

If there is a value for money and safety case for blending, government's intention is to enable blending of hydrogen into the existing gas grid at the earliest from 2023, as a measure to help bring forward early hydrogen production.

We will engage with industry and regulators to develop the safety case, technical and cost effectiveness assessments of blending up to 20 per cent hydrogen (by volume) into the existing gas network. Ahead of the completion of safety trials, we aim to provide an indicative assessment of the value for money case for blending by autumn 2022, with a final policy decision likely to take place in late 2023.

Appendix B

Stakeholders engaged in NTS Survey

Please note, to provide anonymity with responses provided, the stakeholder numbering below does not correlate with the numbering in the survey response results found in Section 3.

Table B-1: Overview of stakeholders engaged throughout the study to inform the evidence base of hydrogen blending acceptability.

Stakeholder type	Stakeholder	Description
NTS-connected power generator	Power generation site(s) owner 1	Gas turbine power generation site(s).
	Power generation site(s) owner 2	Gas turbine power generation site(s).
	Power generation site(s) owner 3	Gas turbine power generation site(s).
	Power generation site(s) owner 4	Gas turbine power generation site(s).
	Power generation site(s) owner 5	Gas turbine + indirect firing power generation site(s).
	Power generation site(s) owner 6	CCGT power generation site(s).
	Power generation site(s) owner 7	CCGT, gas fired and flexible gas site(s).
	Power generation site(s) owner 8	CHP, gas-fired CHP and CCGT site(s).
	Power generation site(s) owner 9	CCGT and flexible CCGT site(s).
	Power generation site(s) owner 10	CCGT and gas-fired site(s).
	Power generation site(s) owner 11	CCGT power generation site(s).
	Power generation site(s) owner 12	CCGT power generation site(s).
	Power generation site(s) owner 13	Gas-fired turbine power generation site(s).

	Power generation site(s) owner 14	Reciprocating engine power generation site(s).
NTS-connected industrial user	Industrial user 1	Industrial sites using gas turbines, indirect firing and also using natural gas as chemical feedstocks.
	Industrial user 2	Hydrogen production facility located with indirect firing and also using natural gas as chemical feedstocks.
	Industrial user 3	Glass manufacturing facility using direct + indirect firing.
	Industrial user 4	Chemical plant.
	Industrial user 5	Gas turbine power generation package manufacturer.
	Industrial user 6	Paper manufacturer.
OEM	OEM 1	Manufacture of gas turbines, gas compressors, control systems and heat exchangers used by offtakers of NTS
	OEM 2	Manufacturer of equipment including gas turbines, compressors, control systems and Heat Recovery Steam Generators.
	OEM 3	Manufacturer of reciprocating gas engines used by some NTS offtakers.
	OEM 4	Manufacturer of reciprocating gas engines used by some NTS offtakers.
	OEM 5	Manufacturer of gas turbines, gas compressors, control systems and heat exchangers used by offtakers of NTS.
Storage	Storage site(s) owner 1	Salt cavern natural gas storage.
	Storage site(s) owner 2	Converted LNG facility storing natural gas.
	Storage site(s) owner 3	Depleted underground reservoir storing natural gas.
	Storage site(s) owner 4	Dormant storage offering future storage potential.
	Storage site(s) owner 5	Depleted oil reservoir storing natural gas.
	Storage site(s) owner 6	Depleted gas reservoir storing natural gas.
	Storage site(s) owner 7	Salt cavern natural gas storage.

Appendix C

Deblending cost estimates

The below table uses a range of the estimated specific costs from National Grid (now National Gas) estimates [72], which have a broad range, and have not been tested for accuracy at the national-level commercial scale of which this applies. The calculated values are for theoretical purposes only, with a high level of uncertainty due to the fact the gas usage for each user is a rough estimate. For more accurate estimates, a commercial scale deblending study must be completed.

Table C-1: Estimate site deblending costs.

No	Archetype	Gas usage from survey response (MWh/day)	Note on usage	Required hydrogen for 20% H2 blend (kg)	Daily Costs (£/kg)			Yearly Costs (£/kg)		
					£1.00	**£1.40**	**£1.60**	**£1.00**	**£1.40**	**£1.60**
1	Gas Turbine	11,562	Total value of gas used annually divided equally between each site for calculation	19,711	£19,711	£27,595	£31,538	£7,194,515	£10,072,321	£11,511,224

2	Gas Turbine	19,200	Must-run requirements of facility	32,725	£32,725	£45,815	£52,360	£11,944,625	£16,722,475	£19,111,400
3	Reciprocating Engine	1,429	Total of facilities	2,433	£2,433	£3,406	£3,893	£888,045	£1,243,263	£1,420,872
4	Direct Firing + Indirect Firing	1,772	Gas consumption of furnace	3,018	£3,018	£4,225	£4,829	£1,101,570	£1,542,198	£1,762,512