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HYDROGEN BLENDING AND THE GAS COMMERCIAL FRAMEWORK

Report on conclusions of NIA study

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EXECUTIVE SUMMARY

The Committee on Climate Change (CCC) has highlighted that low-carbon hydrogen should play a significant role in meeting the UK's net zero target. In its 'Further Ambition' scenario, it predicts that, by 2050, up to 270TWh of low-carbon hydrogen would be required in a year.[1]

Blending hydrogen into the gas grid could be an important stepping stone during the transition to a sustainable, net zero system. In particular, it may:

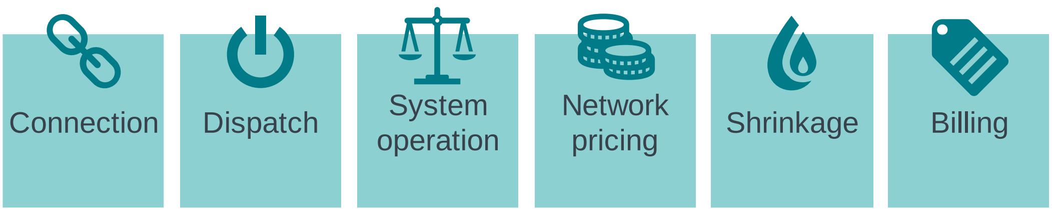
- provide a significant and reliable source of demand for hydrogen producers, supporting the investment case for hydrogen;
- provide learnings and incremental change towards what could potentially become a 100% hydrogen grid; and
- immediately decarbonise a portion of the gas flowing through the grid.

Technical questions relating to hydrogen blending are being taken forward by the industry (e.g. through the HyDeploy project in relation to the maximum potential blend of hydrogen that can be accommodated without end user appliances needing to be altered or replaced). But if blending is to take place, changes to commercial arrangements will be necessary, as today these assume a relatively uniform gas quality. In particular, the commercial framework will need to ensure that limits on the percentage of hydrogen that can safely be blended (currently expected to be around 20% by volume) are not exceeded.

We have been commissioned by Cadent to undertake a Network Innovation Allowance (NIA) project to identify the changes required to the gas commercial framework that will enable hydrogen blending in the GB gas grid, and to set out a roadmap for how these can be delivered. This report sets out our recommendations.

We have focused on six components of the commercial framework, as set out in Figure 1 below. We note that there are some important limitations to the scope of this project (see Section 2.1). For instance, work around adjusting billing to final customers to reflect different calorific values (CVs) at different points in the grid is being considered by a separate NIC project,[2] and is therefore outside the scope of this work.

Figure 1 Key components of the commercial framework



Source: Frontier Economics

[1] CCC (2019), *Net Zero Technical report*, https://www.theccc.org.uk/wp-content/uploads/2019/05/Net-Zero-Technical-report-CCC.pdf, p.21.

[2] https://futurebillingmethodology.com/.

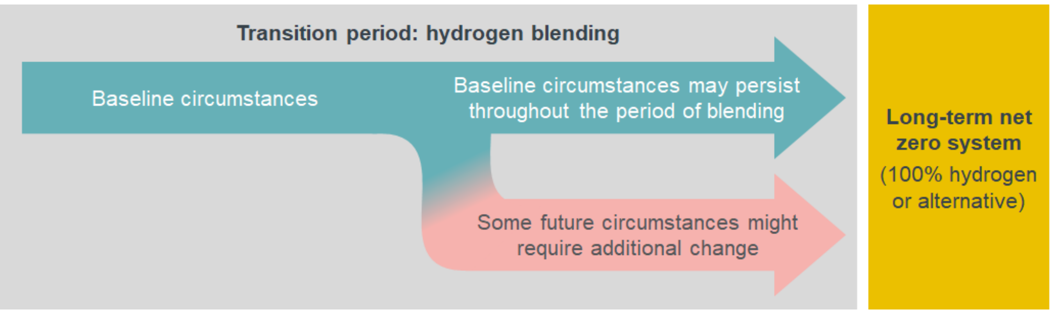
The government will need to introduce funding arrangements to support low-carbon hydrogen production. In our study we assume that the funding arrangements are in place to support hydrogen facilities (rather than using this study to identify what they are). As such, our study is focused on the impact of the connection and operation of hydrogen facilities, rather than how to incentivise and fund hydrogen deployment itself. However, we note that there is an interaction between production incentives and commercial arrangements, and future work by Ofgem and the networks will therefore need to consider the interactions between the policy support mechanism and commercial framework in more detail when more is known about the form of government support.

Our work has focused on what we refer to as baseline circumstances. In this phase of hydrogen blending, there will be only a relatively small number of hydrogen connections, located at dispersed points on the transmission and/or distribution networks. This will mean that the hydrogen blend limit is rarely reached at any given point on the system. It is possible that these baseline circumstances could persist for some time, potentially all the way to a net zero system.

We have also thought about periods beyond the baseline circumstances during which more complex commercial arrangements might be required. We have evaluated whether our baseline recommendations are robust enough to work across different future pathways, and have taken into account any relevant 'path dependency' in our baseline recommendations.

The two plausible pathways for the hydrogen blending transition are illustrated in Figure 2 below.

Figure 2 Likely development of a hydrogen blended system



Source: Frontier Economics

Our report:

- sets out that the existing commercial framework can remain mostly intact, including energy trading and balancing arrangements. Only a limited number of changes need to take place to enable hydrogen blending in the baseline circumstances;
- identifies a clear, phased 'roadmap', which will both enable early producers to connect; and establish a more standardised framework as the market grows. Most of our recommended changes can be made using existing industry processes; and
- provides a set of next steps for the government, Ofgem and the industry.

1.1 Changes to enable hydrogen blending

Recommendation 1: Managing blend and gas quality

Key issues:

- How is the hydrogen blend kept within the blend limit?
- How is network capacity allocated to hydrogen producers?
- How are any specific gas requirements of certain user types managed?

Recommended solution:

A pre-connection impact assessment should be undertaken by the relevant network operator to determine a hydrogen producer's likely impact on the ability of other hydrogen producers to inject (e.g. if the producer looking to connect is likely to cause the gas in a given location to reach the blend limit, this will limit the ability of producers downstream to inject). The evaluation could also assess the production facility's likely impact on certain users with specific gas requirements, such as industrial or commercial users. If the potential impact is found to be significant, an alternative location for the connection would need to be found.[3] [4]

Once connected, hydrogen producers should be subject to constraints on their rights to inject gas into the grid. In particular, an injection blend constraint would apply, meaning any gas injected must not cause the grid in the vicinity to breach the hydrogen blend limit. There could also be constraints on the impact of blending on aspects of gas quality, such as the Wobbe Index.

The system operator or relevant gas distribution network (GDN) could play a 'backstop' safety role in relation to hydrogen producers connected to its network. This would involve monitoring the hydrogen blend across its network, and curtailing producers where necessary for safety reasons.

Recommendation 2: Distribution and transmission charges

Key issue: How can it be ensured that distribution and transmission charges (i.e. capacity and commodity charges, and connection charges) are cost-reflective and facilitate competition in a hydrogen blended system?

Recommended solution: The current distribution charging framework was designed for a system where gas entered from the national transmission system (NTS). In 2013, the framework was amended to reflect more accurately the costs associated with biomethane connections (i.e. the introduction of the Local Distribution Zone System Entry Commodity Charge (LDZ SECC)).[5]

Hydrogen blending (and ongoing biomethane development) may result in a larger number of distribution entry connections. However, the cost reflectivity of the overall distribution charging regime and the impact on effective competition may

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3 Alternatively, deblending may be an option for users with specific gas requirements in future.

4 Currently, networks cannot decline to offer entry connection terms to applicants, although this may not apply to hydrogen connections as the relevant legislation specifically covers methane. This solution might therefore require change to the current framework, for example to licence conditions.

5 Ofgem (2012), *Uniform Network Code (UNC) Modification 391 (UNC391): Distributed Gas Charging Arrangements*, https://gasgov-mst-files.s3.eu-west-1.amazonaws.com/s3fs-public/ggf/UNC391D.pdf.

need to be revisited since hydrogen blending (and ongoing biomethane development) may result in a larger number of distribution entry connections.

We recommend:

- adjusting the connection boundary from a 'deep connection boundary'[6] to a 'shallow connection boundary'[7]; and
- replacing the LDZ SECC with an entry capacity charge based on long-run marginal cost (LRMC), applied to entry injections at the distribution level.

These amendments will improve the cost-reflectivity of the charging regime and facilitate effective competition between network users (e.g. by avoiding some of the downsides of the deep connection charge). Such a change will take time and effort, and the benefit will ultimately depend on the scale of distribution connections. This recommendation should therefore be tested further as more information becomes available.

We also assessed whether transmission charges are cost-reflective and facilitate effective competition in a hydrogen blended system. Ofgem has recently approved amendments to transmission network charges, implementing a postage stamp regime. A shallow connection boundary is in place at entry to the NTS. We do not expect that hydrogen blending is likely to change Ofgem's assessment of cost-reflectivity and effective competition of the postage stamp pricing in the near term. We therefore recommend no change to the status quo arrangements for transmission charges.

Recommendation 3: Level playing field between distribution and transmission-connected plant

Key issue: How can it be ensured that the rules and charging methodology create a level playing field for hydrogen producers connected to transmission and distribution networks, as well as across GDNs?

Recommended solution:

In the current regime:

- the connection charging boundary is not consistent between the distribution and transmission networks; and
- there is no common charging methodology for entry connections across GDNs.

From an efficiency perspective, inconsistencies in relation to the methodology for charging for entry connections is only a concern if it incentivises producers to connect to a particular network or at a particular network level, even if it is not the most efficient place to locate. Traditionally, gas has been injected directly to the transmission network, rather than the distribution network (although more recently, biomethane plants have connected to the distribution network). Therefore, it is unlikely that the inconsistencies in the existing regime would have caused material distortions under the current circumstances. However, if a larger number of

[6] Under a 'deep connection boundary', the connection charges recover both costs of the extension assets and some of the deep reinforcement costs to the network as a result of the user's connection.

[7] Under a 'shallow connection boundary', the connection charges recover only the costs of the extension assets.

connections (hydrogen and biomethane) are connecting at the distribution and transmission levels in the near term, these issues will need to be further considered.

Our recommendations above on the network charges will result in a consistent (shallow) connection boundary. Therefore, the only additional question to consider is whether to implement a common charging methodology for entry connections across the GDNs.

We recommend adopting such a common charging methodology (e.g. in relation to ownership of entry equipment) across the GDNs as it will facilitate effective competition between network users connected at different networks. However, again we note that such a change will take time and effort, and so it should be tested further as more information becomes available.

1.2 Roadmap to deliver recommended changes

We have developed a roadmap that sets out the key areas of work that will be needed to deliver these changes, the relevant group/body best placed to do this, and a suitable sequencing and timing of actions.

The roadmap focuses on actions to enable hydrogen blending under the baseline circumstances described above. If hydrogen blending develops in a way that requires more complex commercial arrangements, the framework developed through the roadmap can be adapted incrementally to implement those arrangements.

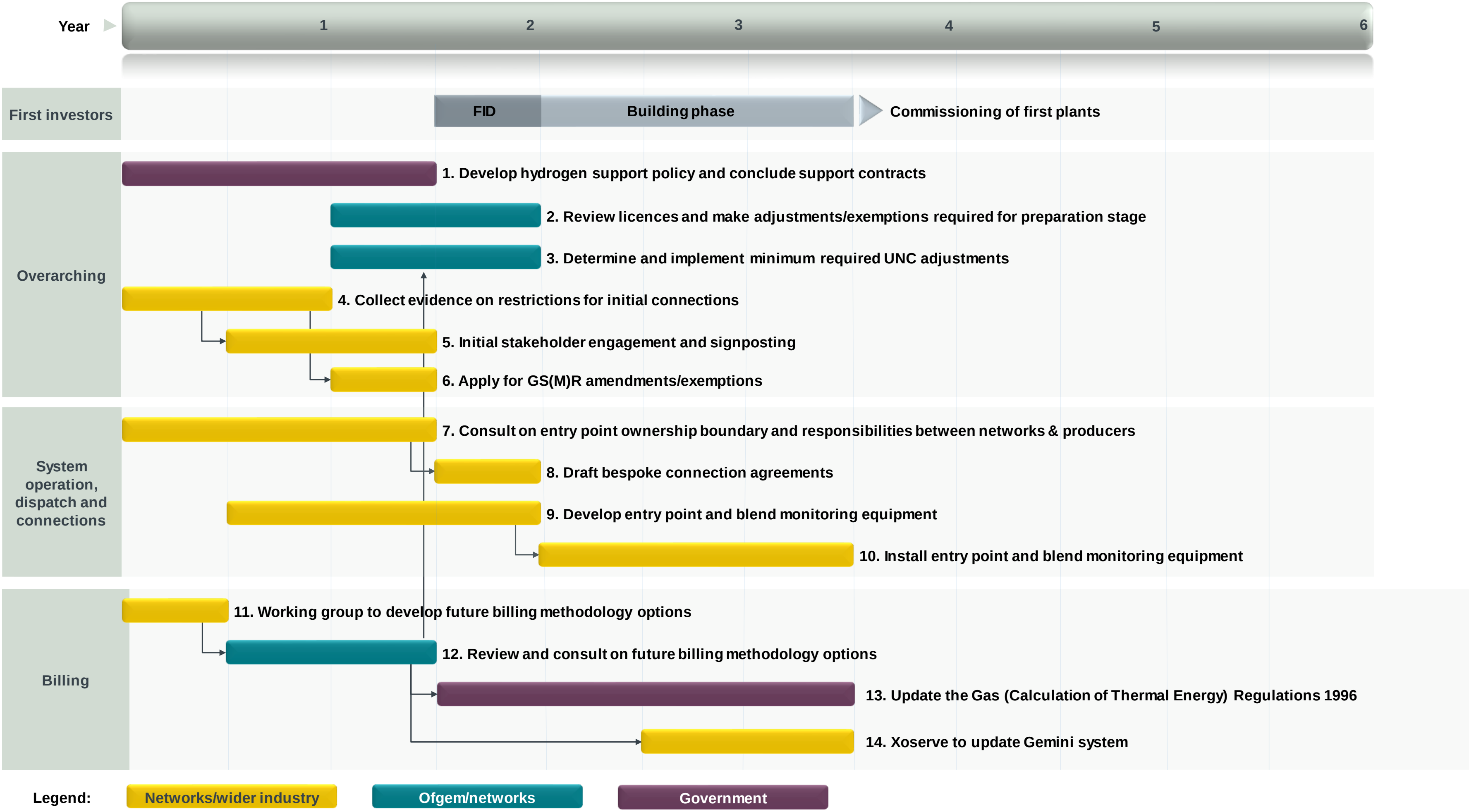
Within the roadmap we have suggested two stages of work:

- **Preparation stage**, which relates to actions required to enable the first early hydrogen producers to connect. In this stage we focus on the minimum changes required, as we assume these producers can be treated in a more bespoke fashion (for example with restrictions on where they are able to connect and with site-specific conditions). An early action during this stage will also involve networks engaging with developers and signposting when and how treatment will transition from these bespoke arrangements to the more standardised ones envisaged in the next stage.
- **Standardisation stage**, which relates to developing a standardised and more comprehensive framework for hydrogen blending. This stage involves tasks required to ensure a framework that can accommodate further production facilities as and when they seek to connect.

While these two stages of work could be carried out sequentially, it is likely to be desirable to start some of the actions for standardisation sooner than this, meaning that the two phases would overlap.

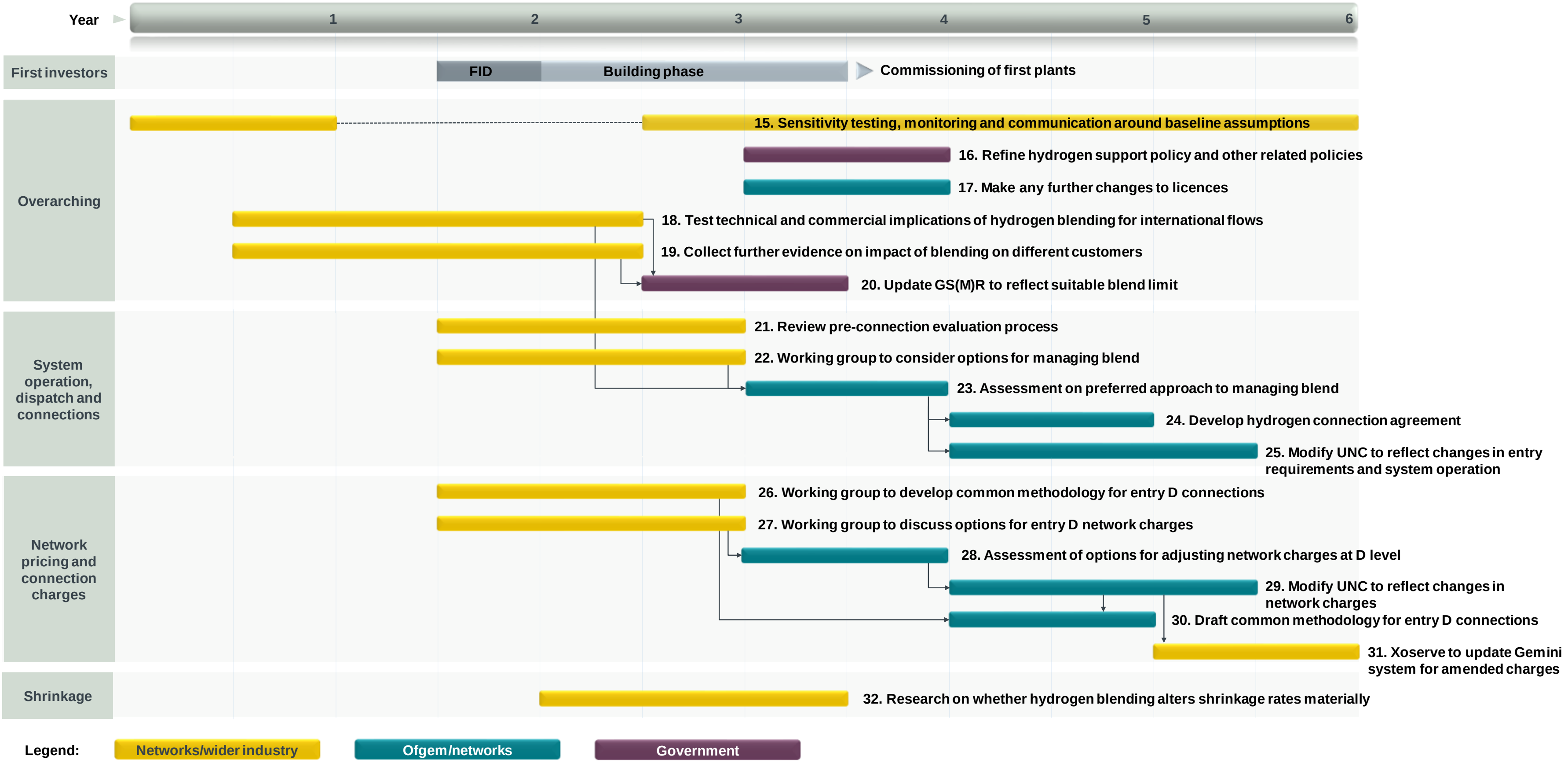
The roadmap is shown below, split out into preparation and standardisation stages. More detailed explanations of each of the actions in the roadmap are provided in section 4 of this report.

Figure 3 Roadmap – preparation stage



Source: Frontier Economics

Figure 4 Roadmap – standardisation stage



Source: Frontier Economics

The sequencing of actions in the roadmap reflects:

- interactions with the investment decisions of the first few hydrogen plants, e.g. some actions will need to be undertaken before the first few hydrogen investors can make a final investment decision (FID);
- dependencies on the first few hydrogen plants – some actions can only be initiated after the FID or the building phase of the first few hydrogen plants as they will draw on learnings from that process; and
- dependencies with other actions, taking into account that the outputs of some actions are an input to other actions.

We recognise that the actual duration of each action and the overall length of the roadmap are highly uncertain, since they will depend on the issues that arise, how quickly inputs can be collected from stakeholders, the development of hydrogen production technologies, etc. The estimates provided should therefore be viewed as indicative and kept under review.

1.3 Next steps

At present, there is no large-scale production of low-carbon hydrogen in the UK. For hydrogen to be the viable option envisaged by the CCC, early deployment projects must get off the ground in the 2020s.[8] Recent policy announcements indicate that the government is committed to explore the option of hydrogen in the transition to net zero.[9]

It is important that the commercial framework does not act as a barrier to this policy aim. Ofgem and the industry therefore need a signal that they can prioritise work to make sure that this does not happen. Ideally the government needs to make clear that hydrogen blending – if proven to be technically feasible – is seen as an important transitional option, and make clear when it hopes early low-carbon hydrogen projects will be connected.

Clear signals from government will allow early action to be taken on tasks that have a longer lead time and will allow more time for considering options and building in learnings from other areas of work, such as from biomethane. Such signals will also mean that development of the commercial framework for low-carbon hydrogen can be properly joined up with the work on biomethane (for example, in relation to the arrangements for connection and network charging at the distribution level), where industry discussions are ongoing.

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8 The CCC has also recommended that the government develop a low carbon hydrogen strategy by the first half of 2021. See: CCC (2020) Reducing UK emissions, Progress Report to Parliament,

https://www.theccc.org.uk/wp-content/uploads/2020/06/Reducing-UK-emissions-Progress-Report-to-Parliament-Committee-on-Cli.._-002-1.pdf, p31

9 BEIS (2019), *Business models for CCUS; Consultation*, https://www.gov.uk/government/consultations/carbon-capture-usage-and-storage-ccus-business-models.

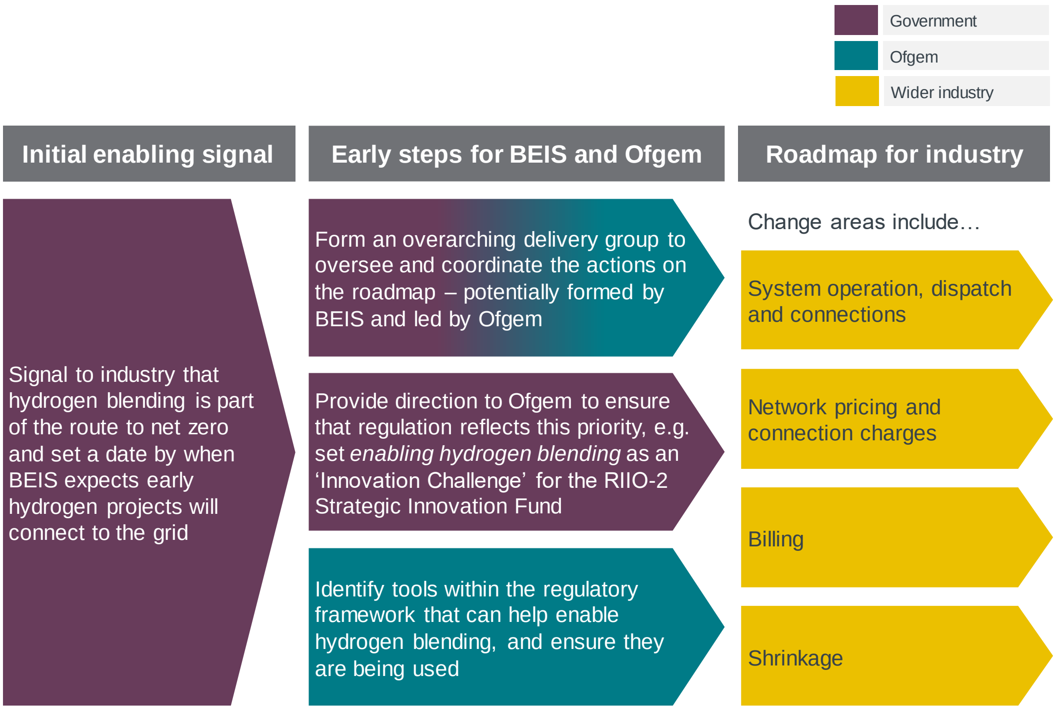
BEIS (2020), *Future support for low carbon heat; Consultation*, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/888736/future-support-for-low-carbon-heat-consultation.pdf.

HM Government (2019), *Offshore Wind Sector Deal: Industrial Strategy*, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/790950/BEIS_Offshore_Wind_Single_Pages_web_optimised.pdf.

Once the government has given a high-level policy direction, it can also work with Ofgem to ensure that this priority is reflected in Ofgem's regulatory framework and forward workplan. For example, as part of the RIIO-2 price control framework, Ofgem is introducing a Strategic Innovation Fund for projects focusing on achieving net zero targets. Ofgem has said that it will collaborate with organisations including BEIS, UKRI and the HSE to set innovation challenges. Through this channel, the government should provide clear direction that enabling hydrogen blending should be a key focus for the Strategic Innovation Fund.[10]

The diagram below illustrates immediate next steps that BEIS and Ofgem can take in order to enable the industry to start work on the commercial framework.

Figure 5 Next steps for BEIS and Ofgem



Source: Frontier Economics

However, there are some steps in the roadmap that the industry can initiate immediately. They are low-regret (they involve low resource costs and keep options open) and most will require a degree of coordination with biomethane:

- Discuss entry point ownership boundary and responsibilities between networks and producers.
- Forum to develop future billing methodology options.
- Sensitivity testing of baseline assumptions.
- Forum to consider options for managing hydrogen blend.
- Forum to develop common methodology for distribution entry connections.
- Forum to discuss options for distribution network charges.

[10] Ofgem (2020), *RIIO-2 Draft Determinations – Core Document*, https://www.ofgem.gov.uk/system/files/docs/2020/07/draft_determinations_-_core_document_redacted.pdf.

There may be other actions that the government and Ofgem consider should be completed immediately, for example to inform decisions they are currently making around the future role of hydrogen blending. If so, these should be communicated to stakeholders so that their completion can be prioritised.

2 INTRODUCTION AND CONTEXT

The CCC has highlighted that low-carbon hydrogen should play a significant role in meeting the UK's net zero target: the CCC predicts that up to 270TWh of low-carbon hydrogen would be needed in its 'Further Ambition' scenario.[11] However, at present, there is no large-scale production of low-carbon hydrogen in the UK. For hydrogen to be the viable option envisaged by the CCC, early deployment projects must get off the ground in the 2020s.

Blending hydrogen into the gas grid can form a helpful stepping stone during the transition to a sustainable, net zero system. In particular, it may:

- provide a significant and reliable source of demand for hydrogen producers, supporting the investment case for hydrogen;
- provide learnings and incremental change towards what could potentially become a 100% hydrogen grid;
- immediately decarbonise a portion of the gas flowing through the grid; and[12]
- help raise public awareness of hydrogen, which would be needed if a transition to a 100% hydrogen system were to happen.

We have been commissioned by Cadent as part of a Network Innovation Allowance (NIA) project. The aim of this work has been to identify changes required to the gas commercial framework to enable hydrogen blending in the GB gas grid, and to provide a roadmap for the industry to deliver these changes.

In this section we set out the objectives and scope of the project, and the framework we have used in carrying out this work.

2.1 Objectives and scope of this project

There is ongoing work to demonstrate the technical acceptability and develop the evidence base around hydrogen blending. In particular, HyDeploy is a network innovation project being led by Cadent and Northern Gas Networks.[13] It aims to investigate the maximum potential blend of hydrogen that can be accommodated without end user appliances needing to be altered or replaced. It is expected that blends of up to 20% by volume may be demonstrated. Following this, we expect that further technical work will need to be carried out to assess the impact of hydrogen blending on other customers, in particular industrial and commercial gas users.

As well as building technical understanding, commercial arrangements will need to be adapted or introduced to enable a blended gas system. The current gas commercial framework has been developed in the context of transporting and trading a relatively uniform gas. Blending will require changes to that framework to

[11] CCC (2019), *Net Zero Technical report*, https://www.theccc.org.uk/wp-content/uploads/2019/05/Net-Zero-Technical-report-CCC.pdf, p.21

[12] As part of its funding bid for HyDeploy 2, Cadent estimated that the adoption of blended hydrogen and natural gas could save an estimated 120Mt CO_2 by 2050 across GB. It could also lead to a saving for consumers of £8 billion cumulatively to 2050, when compared to the installation and network reinforcement required to move forward with heat pump solutions.

[13] https://hydeploy.co.uk/

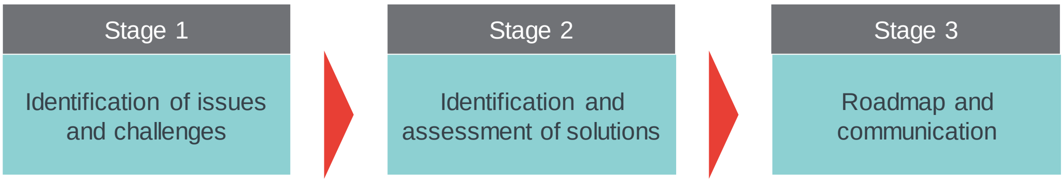
ensure that a new type of gas can enter the grid, and that the industry has the right tools and incentives to manage a blended system.

The aims of this project were to:

- identify any issues and challenges that would arise if hydrogen blending were introduced under the current commercial framework;
- develop solution packages to address these issues, and assess these packages to provide recommended solutions; and
- develop a roadmap for the industry, setting out areas of work that need to be taken forward to implement the recommended solution packages.

Our work was structured around these three aims, as illustrated below. Further detail on our approach is set out in Annex A.

Figure 6 Overview of approach

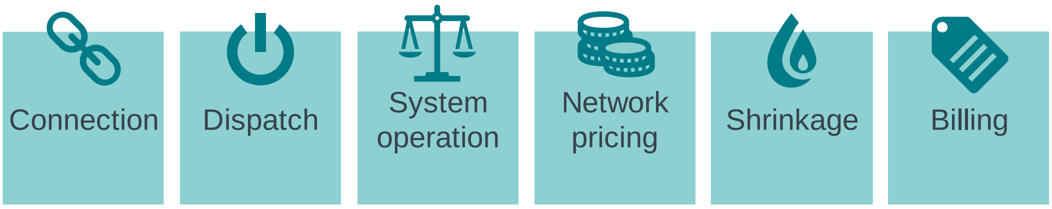


Source: Frontier Economics

We also engaged extensively with relevant stakeholders including network representatives, industry bodies, BEIS and Ofgem to develop, test and challenge our findings at each stage and to ensure that solutions have support and are feasible to implement. We worked particularly closely with a panel of industry experts, who we would like to thank for their time and inputs throughout this project.[14]

We have focused on six components of the commercial framework, as set out in Figure 7 below.

Figure 7 Key components of the commercial framework



Source: Frontier Economics

In Figure 8 below, we provide some key examples of how each of these six elements may need to be adapted to enable hydrogen blending.

[14] This includes (in alphabetical order): Bethan Winter (Wales&West Utilities), Joanna Ferguson (Northern Gas Networks), Joseph Mitchell (SGN), Julie Cox (Energy UK), Lorna Millington (Cadent), Marin Lambert (Oxford Energy), Mark Schofield (Trinity Organics), Stuart Easterbrook (Cadent), Susannah Ferris (National Grid Gas), Victoria Mustard (Xoserve).

Figure 8 Components of the commercial framework and how they may need to change to enable hydrogen blending

Component	Examples of key requirements
Connection	A regime will be needed to enable the connection of new production facilities, in parallel and alongside other gas entry connections. The regime must enable the connection of: ▪ a greater number of new connections; and ▪ a greater diversity in size and location of new connections.
Dispatch	Dispatch (i.e. injection of gas into the grid) must be managed to ensure that the maximum blend is not breached at any time. Ideally the commercial framework would facilitate economic and environmental dispatch, while being consistent with the system for gas energy daily balancing.
System operation	Processes and systems must be in place to deal with the interaction with other gas injections and large loads.
Network pricing	Transportation changes (entry and exit) will need to take account of hydrogen injection points and flows.
Shrinkage	A shrinkage regime is required that will take into account the lower CV of hydrogen gas injections and potentially different shrinkage properties.
Billing	The cost of transportation and localised system operation and management to end-users in different parts of the network may vary significantly depending on the blend level of hydrogen in that area. At the same time, end users will not have a choice over the blend of gas that is supplied to them. This may necessitate moving away from the current system of passing on the network costs of transportation in different LDZs to customers in full. In addition, in a blended hydrogen system, billing may need to be adjusted to reflect varying CV at different points in the grid. As noted below, this topic is being considered in a separate project and is not considered in our work.

Limitations to scope

There are some important limitations to the scope of this project, as described below. However, we do set out in the roadmap where further work needs to be undertaken in these areas, or where ongoing work in these areas can feed into other workstreams.

- **Accommodating gases of different calorific values (CVs) into the billing framework.** Work around adjusting billing to final customers (which is currently volumetric) to reflect different CV at different points in the grid is being considered in a separate NIC project.[15] It is therefore outside the scope of this work. However, these implications do need to be considered and we set this out in the roadmap.
- **Trading arrangements.** We assume that there will be no changes to the current National Balancing Point market principle, therefore blending arrangements will need to fit into and around the current process. This means that shippers will continue to trade energy and have imbalances settled on a

[15] https://futurebillingmethodology.com/

national basis, and that any consideration of the impact of blending on shippers and on trading arrangements is outside the scope of this study.

- **International impacts.** The implications for international flows are excluded from this study. However these implications do need to be considered and we set this out in the roadmap.
- **Funding arrangements for hydrogen.** We assume that funding arrangements will eventually be in place to support hydrogen facilities (rather than using this study to identify what those funding arrangements are). As such the study can focus on the impact of connection and operation, not how to incentivise and fund hydrogen deployment itself. However, we do consider interactions between the commercial arrangements discussed in this study and the funding arrangements for hydrogen. For example, the costs of curtailing hydrogen production expressed by a producer may be influenced by the design of the subsidy arrangements.[16]
- **Network investment.** Any network investments required to support blended hydrogen flows are dealt with in the existing regulatory framework for funding and pricing and are not a consideration for this study. We assume that any additional investment required to get the hydrogen onto the grid will be picked up as part of the RIIO framework.

2.2 Our framework

Robustness to outcomes

Given the uncertainty around how hydrogen production will develop and what a blended system could look like, we have avoided making assumptions around what outcomes may materialise. Figure 9 provides some examples of areas of uncertainty for the future role of hydrogen in the gas grid. The commercial framework solutions that we set out in this work are generally robust to any of these outcomes. For example, we have assumed a system that includes injection from multiple hydrogen production plants of varying size and type (including green hydrogen from renewables and blue hydrogen from SMR processes with CCS). These production sites could be connected to the transmission and distribution networks.

Figure 9 Main areas of uncertainty around the future role of hydrogen in the grid

Hydrogen production types	Scale of production	Connection level	Geographical concentration	Storage options	Availability of technologies/ tools	Evolution of demand
▪ Green ▪ Blue ▪ Grey	▪ Large-scale ▪ Small-scale ▪ A mix	▪ NTS ▪ Distribution ▪ A mix	▪ Highly concentrated ▪ Evenly distributed	▪ Abundant ▪ Limited	▪ Deblending ▪ Reverse flows ▪ Others?	▪ Increasing ▪ Flat ▪ Declining

Source: Frontier Economics

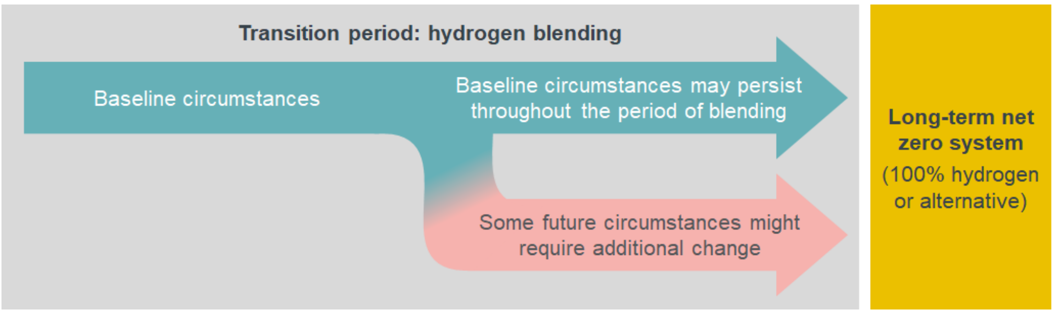
[16] E.g. if subsidy is paid per MWh produced, hydrogen producers are likely to require significant compensation to be curtailed – a problem frequently observed among RES-E producers today.

Recognising that blending is a transitional stage

It is important to recognise that hydrogen blending can only ever be a transitional solution.[17] A sustainable net zero gas system may look very different from a blended system, for example some of the changes required to enable a blended system may not in fact be necessary in a system with 100% hydrogen. It may therefore not be sensible to instigate a large number of complex changes to the commercial framework that are designed to work only in limited circumstances. Any major change should ideally be compatible with the direction of future travel, otherwise a simpler, interim solution may make more sense.

We have therefore structured our work around the likely development of a hydrogen blended system over time. Importantly, we have identified a set of 'baseline circumstances' that are likely to apply in the near term when hydrogen production is at early stages and limited numbers of producers are connected to the grid. Over time, these baseline circumstances may or may not persist (see Figure 10 below), but focusing on addressing issues that arise under these baseline circumstances in the first instance helps ensure that a 'low-regrets' approach is taken to changing the commercial framework.

Figure 10 Likely development of a hydrogen blended system



Source: Frontier Economics

The main assumptions we have made around baseline circumstances and other future circumstances are as follows.

- **Baseline circumstances.** The number and location of hydrogen connections mean that the hydrogen blend limit is rarely reached. This may be because hydrogen injections are only NTS-connected, and/or there may be a manageable number of sufficiently dispersed distribution-connected production facilities.
- **Some future circumstances.** These circumstances might involve one or more of the following.
  - The blending cap is reached frequently, at multiple locations. This may be because there are large number of producers looking to connect at both NTS and distribution level.
  - Blending is expected to persist for a long time before switching to long-term net zero system is feasible, so there may be merit in implementing more extensive changes that achieve more efficient outcomes.

[17] Although we note that there could be a net zero scenario involving some blending of hydrogen and biomethane in certain areas.

- Existing arrangements are leading to significantly distorted investment decisions (e.g. inefficient producer location).

This framework has helped us take a view on which changes to the commercial framework are needed in the near term, versus those that should be made only in response to certain future circumstances arising. This means that the roadmap to enable hydrogen blending represents a realistic and proportionate set of actions for the industry to take forward in light of uncertainty around how hydrogen blending will evolve. Key areas where this framework has fed into our work are:

- **identifying issues:** we first identified a long list of issues that could potentially arise due to hydrogen blending, but only a small subset of these issues apply under the baseline circumstances;
- **setting out solutions:** we only considered in detail solutions to the subset of issues relevant under baseline circumstances. However, we did also set out at a high level solutions to issues that could arise under alternative future circumstances. We did this to test path dependency, i.e. how future scenarios might affect the choice of solution in the near term; and
- **building the roadmap:** the roadmap is focused on enabling hydrogen blending under baseline circumstances. Beyond this, industry governance processes can be relied on to make incremental changes to the framework for hydrogen blending based on how the hydrogen market develops.

Link with government policy on hydrogen support

The government will need to introduce funding arrangements to support low-carbon hydrogen production.[18] In our study we assume that the funding arrangements are in place to support hydrogen facilities (rather than using this study to identify what they are). As such, our study is focused on the impact of the connection and operation of hydrogen facilities, rather than how to incentivise and fund hydrogen deployment itself.

However, we note that there is an interaction between the production incentives and the commercial arrangements. For example, the costs of curtailing hydrogen production may be influenced by the design of the subsidy arrangements. This suggests that designing the commercial framework to enable hydrogen blending should also consider interactions between the commercial framework and the support policy. This assessment will ensure that the commercial framework and production incentives are consistent and that interactions between the two do not result in undesirable outcomes for customers or investors.

Since the form of hydrogen support, and when it will be introduced, is currently uncertain, we have not sought to evaluate all plausible combinations of government support schemes and the commercial arrangements. Future work by Ofgem and the networks will need to consider the interactions between the policy support mechanism and commercial framework in more detail (e.g. in future

[18] We note that BEIS' consultation on the key aspects of policy design to support biomethane production also invited views on what mechanisms might be appropriate for long term support of alternative sources of green gas such as hydrogen blending in the future. See BEIS (April 2020), Future support for low carbon heat, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/888736/future-support-for-low-carbon-heat-consultation.pdf.

consultations) when more is known about the form of government support. We reflect this action in the roadmap section (see section 4). However we note that there is likely to be value in networks commencing early work on the commercial framework ahead of the support mechanism being defined, and a signal from government will be necessary to achieve this.

That said, we expect the interactions between the policy framework and commercial arrangements to be less significant under the baseline for the following reasons.

- Our baseline assumption is that there are not significant constraints to producers caused by the hydrogen blending cap. This means that the interactions between the form of support (e.g. whether it is output-based) and the risk and cost of curtailment are less significant.
- For the early producers, it may be reasonable to expect support mechanisms to be sufficiently tailored to ensure that the choices made by those producers (e.g. around where to locate and when to produce) work in harmony with the commercial framework to minimise the impact of distortions.

2.3 Structure of this report

The remainder of the report is structured as follows:

- Section 3 summarises the recommended areas of change to the current gas commercial framework, to enable hydrogen blending;
- Section 4 presents the roadmap of commercial and regulatory actions necessary to achieve hydrogen blending in the early stages, as well as at a later stage once many producers connect; and
- Section 5 presents the main conclusions of our report.

Annex A provides an overview of the process we have carried out during the course of this work. Annex B sets out the relevant objectives of the UNC for assessing network charges. Annex C provides an overview of the development of the commercial and policy framework for biomethane producers. Annex D provides more detail on how we reached the conclusions summarised in the sections below.

3 AREAS OF CHANGE IN THE COMMERCIAL FRAMEWORK TO ENABLE HYDROGEN BLENDING

In this section we identify the changes that will need to be made to the existing commercial framework to enable hydrogen blending.

3.1 Our approach

3.1.1 Methodology

Our recommendations for adapting the commercial framework are based on our methodology set out in Annex A and summarised below.

- **Identification of issues**: we identify a full set of issues associated with the commercial framework that would need to be addressed to enable hydrogen blending. We distinguish between issues that need to be addressed to enable hydrogen blending under a set of baseline circumstances, and issues that might arise under more complex circumstances. We group these issues under areas of change where they relate to the same components of the commercial framework and a common solution can be found.
- **Long list of solutions for change**: for each area of change, we develop a long list of solutions.
- **Evaluation**: we assess our list of solutions under the baseline circumstances against a set of criteria (see Figure 11). When we evaluate solutions under the baseline circumstances we take into account changes that could be required under more complex future scenarios. This ensures that our solutions are robust to potential future change.
- **Recommendations**: on the basis of our evaluation, we identify a preferred baseline solution.

Figure 11 Criteria for successful solutions

Efficiency	Does the solution create incentives for the efficient use and development of network capacity?
	Does the solution minimise the magnitude of additional system costs to manage blend?
Feasibility and practicality	Is the change in the commercial framework simple and quick to implement?
	Does the solution limit administrative cost and complexity for networks?
Fairness	Does the solution promote a fair distribution of costs?
Robustness to uncertainty	Does implementing the solution involves a low degree of regret in an end-point with 100% H2?
	Does implementing the solution involves a low degree of regret in an end-point without gas?

Source: Frontier Economics

Throughout this work, we have relied on input from the expert and functional engagement groups, as noted in Section 2. We have also stress tested these findings with BEIS and Ofgem.

Our detailed assessment of the areas of change and solution packages can be found in Annex D. We provide a summary of our findings here.

3.2 Areas of change required to enable blending

A limited set of issues will need to be addressed to enable hydrogen blending under the baseline circumstances. This conclusion is in line with an ACER survey published in July that stated '*blending of hydrogen would not initially require major changes in the current market design and legislation*'.[19]

We have identified four potential areas of change, and their key issues, below.

- **System operation, dispatch and connections.**
  - how is the hydrogen blend kept within the blend limit?
  - how is network capacity allocated to hydrogen producers?
  - how are any specific gas requirements of certain user types managed?
- **Transmission charges (i.e. capacity and commodity charges; and connection charges)**.
  - how to ensure charges are cost-reflective and facilitate effective competition in a hydrogen blended system?
- **Distribution charges (i.e. capacity and commodity charges; and connection charges)**.
  - how to ensure charges are cost-reflective and facilitate effective competition in a hydrogen blended system?
- **Level playing field between distribution and transmission-connected plant**.
  - how to ensure that the rules and charging methodology create a level playing field for hydrogen producers connected to transmission and distribution networks as well as across GDNs?

We note that there are also a small number of additional issues of a technical or legal nature that will need to be considered under baselines circumstances.[20] We do not provide recommendations on how to address these issues, but in our roadmap in Section 4 we set out what additional studies or thinking are required to provide solutions to these issues.

We explain each of the above areas of change in more detail below.

[19] ACER (July 2020), NRA Survey on Hydrogen, Biomethane, and Related Network Adaptations, https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Report%20on%20NRAs%20Survey.%20Hydrogen,%20Biomethane,%20and%20Related%20Network%20Adaptations.docx.pdf, page 9 - 14.

[20] For example, gas quality regulations will need to be adjusted to allow hydrogen blends onto the system. A detailed list of the issues we identified can be found in Annex D.

System operation, dispatch and connections

There are three issues that need to be dealt with. First, during the transitional period of hydrogen blending, it will be essential for safety and operational reasons to ensure that the blend of hydrogen does not exceed a given limit (currently expected to be approximately 20%) at any location on the grid. A robust approach will need to be introduced to manage the hydrogen blend, with clarity around where responsibilities lie.

Second, the need to limit the hydrogen blend at all locations across the grid means that the quantity of hydrogen that can be injected at any given entry point is determined by:

- the volume of gas flowing past that entry point (in turn determined by the wider pattern of demand and injections); and
- the percentage of that gas already made up of hydrogen.

If, for example, the gas flowing past a hydrogen entry point is already at a 20% blend, maximum hydrogen capacity in that location will already have been reached. The commercial framework will therefore need to set out how hydrogen capacity is allocated to producers, and how gas from different producers is dispatched (e.g. which producers are curtailed when the blend limit is reached).

BOX 1: LEARNINGS FROM CONNECTING RENEWABLE ELECTRICITY GENERATION

In 2007, Ofgem and DECC undertook a joint review of the transmission access regime, motivated by the need to accommodate a large volume of renewable electricity to the transmission grid and thereby meet the 2020 renewable energy targets.[21] In 2010, DECC decided to change from an 'Invest and Connect' (I&C) regime to a 'Connect and Manage' (C&M) regime.[22]

Under the initial I&C regime, any necessary grid reinforcement works to increase capacity needed to be fully completed before a new electricity generator could connect. Under the new C&M regime, generators can connect without the need to wait for wider transmission network reinforcement. To accommodate this, NGET needs to constrain off connected generators with firm access rights, and compensate them for curtailment.

Ofgem later assessed that the C&M regime generated environmental benefits by allowing renewable generators to connect early, but also created higher congestion management costs.[23] By way of illustration, in the year leading up to September 2015, the total carbon savings attributable to C&M were 5.9m tonnes

[21] Ofgem (2007), Transmission Access Review, https://www.ofgem.gov.uk/sites/default/files/docs/2007/07/070725_ex_tar-open-letter-and-tor-no-signature_dh3_0.pdf

[22] DECC (2010), Government Response to the technical consultation on the model for improving grid access, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/42979/251-govt-response-grid-access.pdf

[23] Ofgem (2015), Monitoring the 'Connect and Manage' electricity grid access regime, https://www.ofgem.gov.uk/sites/default/files/docs/monitoring_the_connect_and_manage_electricity_grid_access_regime_sixth_report_from_ofgem_0.pdf, paragraph 2.3 and 2.9.

of CO_2, and the C&M congestion costs were £121.7m (roughly 30% of total congestion costs).

Unlike the situation in electricity, the challenge for accommodating hydrogen connections is not only about grid reinforcement - it is primarily driven by the need to manage the level of the hydrogen within the blending cap. Whether or not hydrogen connections can be accommodated depends on the volume of methane that is flowing through the relevant part of the system (which will affect the level of and degree of fluctuations in the hydrogen blend that reaches customers). This is not entirely controllable by the networks since it will depend largely on the level of final demand.

Therefore, the question of whether to adopt I&C or C&M in gas is equivalent to the question of whether to wait to connect until the entry connection can be accommodated as a result of a higher future level of final demand (i.e. analogous to I&C but with demand rather than network capacity as the constraint); *or* to accept the entry connection and compensate them for curtailment (i.e. analogous to C&M).

In the near term, where we assume that the blending constraint is rarely reached, it is likely that most hydrogen connections can be accommodated under the existing I&C approach. However, under certain future circumstances where the baseline assumptions do not hold, an I&C approach might not allow new hydrogen connections to connect in a system with declining demand. In this case, a consideration of the I&C and C&M options may be required to inform the potential future access regime for hydrogen injections.

We note that our expert group expect there will be some instances where network investment can unlock capacity that would enable more hydrogen to be blended. Gas infrastructure investment is likely to have shorter lead than those seen in electricity transmission infrastructure (which led to the issues with the I&C regime). Therefore, the considerations and trade-offs that applied in electricity in relation to network infrastructure itself are less likely to be relevant when considering the question of whether to adopt I&C or C&M in gas.

Finally, blending hydrogen into the grid will impact certain characteristics of the gas received by users and there may be a need to manage these impacts for certain users, such as industrial or commercial users.

For example, the Wobbe Index is a measure of the energy output of gas, and the hydrogen content of blended gas will impact its Wobbe Index. The equipment of industrial users such as CCGTs is often tuned to function optimally in a given Wobbe Index range. Significant or rapid fluctuations in Wobbe Index can have a detrimental impact on the functioning of the equipment. Frameworks (regulatory, policy and/or commercial) will need to set out how any specific gas requirements of certain users (e.g. industrial or commercial) are managed, if at all.

BOX 2: LEARNINGS FROM GERMANY ON MANAGING USER REQUIREMENTS

According to an ACER survey published in July,[24] the German gas TSO accepts the highest concentration of hydrogen in the gas grid across Europe. The applicable hydrogen blending cap is 10% in some sections of its transmission network.

The ACER report explains that in Germany:

- there is an obligation for network operators to provide a connection point for hydrogen injection upon request;
- direct injection of pure hydrogen to the transmission network is only possible if the hydrogen is produced at power-to-gas (PtG) facilities, otherwise it needs to be injected at a 'pre-mix' of hydrogen and other gases meeting the blending cap;
- the TSO is obliged to verify whether it is possible for the producer to inject hydrogen e.g. by assessing whether the hydrogen blending cap is reached in its own network and adjacent networks, and it may refuse further injection if the stability of the cap becomes an issue; and
- the blending cap limit of 10% is only allowed if no 'sensitive' customer is connected to the network, e.g. if a natural gas filling station for vehicles is connected to the gas network, only a 2% blend is permitted.

The solutions to all three issues set out above are likely to be interlinked because:

- the approach to managing blend and how capacity is allocated need to be consistent. For example, the approach to managing blend may require that certain conditions are placed on connections or on capacity rights, or may require the use of interruptible capacity; and
- the approach to managing blend is likely to overlap with any approach to managing gas specifications of certain users (e.g. industrial or commercial), because it is possible that the same tools can be used to address both issues.

We have therefore grouped these issues together and set out solution packages that address all three.

Transmission network charges

We considered whether the existing transmission network charges (i.e. capacity and commodity charges; and connection charges) applied to entry injections remain cost-reflective and facilitate effective competition in a hydrogen blended system.

Under the existing commercial framework, entry injections at the NTS level pay the following charges.

- Entry connection charges are based on a 'shallow connection boundary'. That is, the entry connection charges recover the costs of the extension assets, but

[24] ACER (July 2020), NRA Survey on Hydrogen, Biomethane, and Related Network Adaptations, https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Report%20on%20NRAs%20Survey.%20Hydrogen,%20Biomethane,%20and%20Related%20Network%20Adaptations.docx.pdf, page 9 - 14.

do not recover any deep reinforcement costs to the network as a result of the user's connection.[25]

- Postage stamp network prices (to be implemented from 1 October 2020) that apply a single price[26] per unit of capacity to all entry points to recover the allowed revenue at entry.[27]

Cost-reflectivity

As explained in annex B, the cost-reflectivity principle is based on the premise that network charges should reflect the forward looking marginal costs that users impose on the network. This is important to achieving an economically efficient outcome: if charges are cost-reflective, users will internalise the network costs which they cause when making a decision about how to use the network and where to locate.

Ofgem has recently reviewed and amended the transmission network commodity and capacity charges and implemented the existing postage stamp regime which it considered to be cost-reflective.[28] Ofgem's reasoning was that the marginal cost of additional capacity is close to zero because there is spare capacity on the NTS and little or no demand growth is expected.[29] Under these conditions, the marginal cost based signals for capacity look very similar to the existing postage stamp charges regime.

However, certain circumstances may arise as part of a hydrogen blended system which could mean that the status quo charges are no longer cost reflective. Hydrogen has a lower Calorific Value (CV) than methane. Therefore, a given level of demand for energy (kWh/day) implies a larger hydrogen volume. If, as a result of CV differences, the NTS becomes more capacity constrained then the existing transmission charges may no longer be cost reflective (i.e. they would not fully reflect the forward looking marginal cost that users impose to the network). This is more likely to be significant if there are a large number of hydrogen producers connecting to the transmission level.

Effective competition

As explained in Annex B, effective competition is closely related to cost reflectively in that if tariffs are cost reflective then competition is able to take place on its merits without distortions.

Beyond the impact of cost reflectivity on effective competition, another potential area to consider is the impact of the charging regime on the competitive process

[25] https://gasgov-mst-files.s3.eu-west-1.amazonaws.com/s3fs-public/ggf/Annex%20B%20NTS%20Gas%20Connection%20Methodology%20v2.pdf

[26] We note that the postage stamp price at entry is a reserve price (i.e. the auction floor price for a specific entry/exit point and NTS user). If an NTS user triggers reinforcement costs, it may be required to pay a price above the reserve price.

[27] Ofgem has recently confirmed its decision to move to a postage stamp regime for gas transmission charging, with implementation on 1 October: https://www.ofgem.gov.uk/system/files/docs/2020/05/unc678_-_decision_0.pdf

[28] Ofgem (2020), Uniform Network Code (UNC) Modification (UNC678A): Gas Transmission Charging Regime, https://www.ofgem.gov.uk/system/files/docs/2020/05/unc678_-_decision_0.pdf, pages10-11

[29] Specifically, Ofgem said that it considers the postage stamp regime to be appropriate "*given the gas transmission network is a meshed network largely operating below capacity with expected declining demand and the primary function of these charges as cost recovery*". Ofgem (2020), Uniform Network Code (UNC) Modification (UNC678A): Gas Transmission Charging Regime, https://www.ofgem.gov.uk/system/files/docs/2020/05/unc678_-_decision_0.pdf, page 24.

between gas shippers and between gas suppliers. Factors that will affect the competitive process include the transparency and complexity of the charges, or the methodologies used to calculate them and whether the charges that are not designed to send cost signals (e.g. cost recovery charges) are applied in a non-discriminatory manner.

Similarly to above, Ofgem has recently implemented the existing postage stamp regime which it considered to facilitate effective competition.[30] However, a potential shift away from cost-reflective tariffs in a hydrogen blended system for the reasons described above could create distortions and therefore, reduce effective competition.

In addition, there is a shallow connection boundary at the transmission level (rather than a deep connection boundary). This facilitates effective competition as:

- it lowers the upfront costs of connection;
- it leads to less uncertainty in relation to future connection costs (i.e. under a deep connection charge, the treatment of assets which have been paid for by individual users and which are subsequently used by other users need to be considered which can be complex); and
- it is more transparent, since it avoids the case by case estimation of the relevant reinforcement costs caused by an individual user that can be subjective.

Distribution network charges

We then considered whether the existing distribution network charges applied to injections remain cost-reflective and facilitate effective competition in a hydrogen blended system.

Entry injections at the distribution level pay the following charges under the existing commercial framework.

- Entry connection charges are based on a 'deep connection boundary'. That is, the connection charges recover both costs of the extension assets and some of the deep reinforcement costs to the network as a result of the user's connection.
- A Local Distribution Zone System Entry Commodity Charge (LDZ SECC) which reflects the operational costs associated with the entry of distributed gas directly into the distribution network and some credit elements. The credits reflect:
  - the avoided NTS Exit capacity charge as a result of gas sources not entering the distribution network via the NTS; and
  - the reduced LDZ System use if the injection results in lower usage of certain tiers of the distribution system than would be the case had gas entered from the NTS.

Cost-reflectivity

[30] Ofgem (2020), Uniform Network Code (UNC) Modification (UNC678A): Gas Transmission Charging Regime, https://www.ofgem.gov.uk/system/files/docs/2020/05/unc678_-_decision_0.pdf, page 26.

The distribution charging framework was largely designed for a system where gas entered the distribution network from the NTS, rather than being directly injected into the distribution network. In 2013 an amendment was made to the distribution charges to reflect more accurately the costs associated with biomethane connections at the distribution level (i.e. the introduction of the LDZ SECC).[31] However, the cost reflectivity of the overall distribution charging regime may need to be revisited in circumstances where there are a larger number of distribution entry connections.

First, the credits included in the LDZ SECC relate to charges which include a cost recovery component (i.e. charges that recover historic costs of the network, as well as or instead of forward looking marginal costs imposed by injections). This means that direct connections at the distribution network may receive benefits (equal to the cost recovery component of charges) which do not reflect forward looking costs but rather costs that have already been incurred and cannot be changed irrespective of what new producers do. As such, there is no value in terms of economic efficiency in sending a signal related to these costs and in fact, doing so may distort incentives and change behaviour in a way that reduces efficiency.

While this distortion exists in the current framework (in relation to biomethane injections), any inefficiencies will become more material the larger the number of producers (both biomethane and hydrogen producers) connecting to the network in the near-term.

[31] Ofgem (2012), Uniform Network Code (UNC) Modification 391 (UNC391): Distributed Gas Charging arrangements, https://gasgov-mst-files.s3.eu-west-1.amazonaws.com/s3fs-public/ggf/UNC391D.pdf

BOX 3: LEARNINGS FROM THE ELECTRICITY FRAMEWORK FOR EMBEDDED BENEFITS

In the electricity sector, small (sub-100MW) distribution-connected generators ('embedded generators') avoided certain transmission charges that were paid by transmission-connected generators and larger embedded generators. These are referred to as 'embedded benefits'.[32]

In 2016, Ofgem initiated a review of the electricity transmission network charging arrangements for embedded generators, including the embedded benefits.[33] Ofgem noted that the embedded benefits may over-reward embedded generation.[34] This is because the level of embedded benefits may not reflect the actual benefit in relation to reduction in forward-looking costs that sub-100MW EG provide to the transmission system.

Specifically, Ofgem noted that the connection of an increasing amount of sub-100MW EG to the distribution system logically cannot help to avoid historic costs or fixed costs of developing and maintaining the transmission network. Ofgem said that these benefits were causing distortions, for example generators may choose to locate on the distribution system (instead of the transmission system) so as to receive the embedded benefits, even if it is not necessarily the most efficient place to locate.[35]

The review of the embedded benefits in the electricity sector has parallels to the credits included in the LDZ SECC in the gas sector. Ofgem will need to ensure that the credits included in the LDZ SECC will not cause distortions in a hydrogen blended systems.

Second, the current framework sends locational signals via the deep connection charge at entry in relation to network investment. This approach for sending locational signals in relation to network investment has some limitations:

- locational signals in relation to network investment can only be sent once (upon connection) and so will not send signals reflecting changing conditions on the network to users once they are connected;

[32] For example, one of the embedded benefits arose because transmission charging for demand was previously calculated according to each user's net demand (i.e. total customer demand less any generation output from smaller generators) at particular periods, known as triad periods. As a result, smaller generation was treated not as generation, but as 'negative demand'. This meant that suppliers could use smaller embedded generation to reduce their net demand, and therefore their network charges, and for smaller embedded generation to receive payments for doing so. See Ofgem (2016), Open Letter: Charging arrangements for embedded generation, https://www.ofgem.gov.uk/system/files/docs/2016/07/open_letter_-_charging_arrangments_for_embedded_generation.pdf

[33] Ofgem (2016), Open Letter: Charging arrangements for embedded generation, https://www.ofgem.gov.uk/system/files/docs/2016/07/open_letter_-_charging_arrangments_for_embedded_generation.pdf and Ofgem (2016), Update on charging arrangements for Embedded Generation, https://www.ofgem.gov.uk/system/files/docs/2016/12/update_letter_-_charging_arrangements_for_embedded_generation.pdf

[34] Ofgem (2017), Minded to decision and draft Impact Assessment of industry's proposals (CMP264 and CMP265) to change electricity transmission charging arrangements for Embedded Generators, https://www.ofgem.gov.uk/system/files/docs/2017/03/minded_to_decision_and_draft_impact_assessment_of_industrys_proposals.pdf, page 87.

[35] Ofgem (2017), Minded to decision, paragraphs 2.11-2.12, page 14.

- the treatment of assets which have been paid for by individual users and which are subsequently used by other users who have connected later needs to be considered, and can become complex to deal with; and
- the case by case estimation of the relevant reinforcement costs caused by an individual user (rather than broader change in demand and supply conditions) may be subjective creating the potential for inefficiency, uncertainty and dispute.

These downsides might be more significant in a hydrogen bended system. If the network becomes more capacity constrained under a hydrogen blended system, more accurate and flexible locational signals in relation to network investment may be needed to ensure efficient outcomes. In addition, temporal considerations may be particularly important in a hydrogen blended system, as the level of demand will influence the total gas flow and so the absolute amount of hydrogen which can be accommodated for any given percentage blending constraint.

Effective competition

A potential shift away from cost-reflective tariffs in a hydrogen blended system for the reasons described above could create distortions and therefore, reduce effective competition. In particular, the credits included in the LDZ SECC may introduce undue discrimination between entry connections at the distribution and transmission level (because direct connections at the distribution level receive benefits that do not reflect their impact on the forward looking costs of the distribution network).

In addition, a deep connection boundary may create barriers to entry to new gas sources because:

- there are high upfront costs of connection;
- it leads to uncertainty in relation to future connection costs (since as mentioned above, the treatment of assets which have been paid for by individual users and which are subsequently used by other users need to be considered which can be complex); and
- it is less transparent (since as mentioned above, the case by case estimation of the relevant reinforcement costs caused by an individual user can be subjective).

Level playing field between entry connections

In the sections above on transmission and distribution network charges, we have assessed whether the charges applied for entry injections at each network level in isolation are cost-reflective and facilitate effective competition. If that is the case, then a level playing field between network users is ensured as there are no distortions in the behaviour of network users.

It is important to also review whether the methodologies and rules for setting the network charges create a level playing field between entry connections at the transmission and distribution level as well as across GDNs. This will allow us to assess whether UNC's objective of effective competition is satisfied across users connecting at different networks.

We identified two issues in relation to ensuring a level playing field for entry connections that may need to be addressed to enable hydrogen blending:

- there is no common charging methodology for entry connections across GDNs (e.g. in relation to the methodology for estimating the charges and ownership of entry equipment).[36]
- the connection charging boundary is not consistent between the distribution and transmission networks (i.e. there is a deep connection charge for entry connections at distribution and a shallow connection charge for entry connections at transmission).

From an efficiency perspective, inconsistencies in relation to the methodology for charging for entry connections is only a concern if it incentivises producers to connect to a particular network or at a particular network level, even if it is not the most efficient place to locate. As noted above, traditionally gas has connected directly to the transmission network and it is only over the last few years that biomethane producers have started connecting directly to the distribution network.[37] Therefore, it is unlikely that the inconsistencies in the methodology for charging for entry connections in the existing regime would have caused material distortions under the current circumstances.

If a larger number of connections (hydrogen and biomethane) are connecting at the distribution and transmission levels in the near-term, these issues will need to be further considered and in particular, whether these inconsistencies hinder effective competition across entry connections at the different voltage levels.

3.3 Recommended solution packages to enable blending

For each of the areas of change identified in the section above, we consider alternative solution packages for adapting the commercial framework ('long list of potential solution packages') and evaluate these against our criteria set.

A summary of the evaluation of the long list of solution packages under the baseline circumstances is presented below.[38]

3.3.1 Solution packages for system operation, dispatch and connections

We propose three alternative solution packages to address the identified issues.

- **Solution package 1: injection constraints.**
  - Hydrogen producers are connected subject to entry specifications that apply constraints on their rights to inject gas into the grid. In particular, an

[36] Ofgem (2017), Minded to decision and draft Impact Assessment of industry's proposals (CMP264 and CMP265) to change electricity transmission charging arrangements for Embedded Generators, https://www.ofgem.gov.uk/system/files/docs/2017/03/minded_to_decision_and_draft_impact_assessment_of_industrys_proposals.pdf, paragraphs 2.11-2.12, page 14.

[37] As of 2020, there are less than 100 biomethane producers connected to the gas grid in the UK. *See European Biogas Association,* https://www.europeanbiogas.eu/the-european-biomethane-map-2020-shows-a-51-increase-of-biomethane-plants-in-europe-in-two-years/.

[38] See Annex D for more details on our evaluation.

injection blend constraint would apply, meaning any gas injected must not cause the grid in their vicinity to breach the hydrogen blend limit.

Constraints could also include their impact on aspects of gas quality such as the Wobbe Index, if the relevant network operator considers this necessary.

Learnings around managing gas quality in Morecambe Bay and Lupton are relevant here. Morecambe Bay South gas is outside GS(M)R gas quality specifications, and the pipeline from Morecambe Bay to Lupton has an exemption from GS(M)R requirements. At Lupton, the gas is blended with higher CV gas on the NTS to bring it within GS(M)R specifications before entering the grid. If there is insufficient high CV gas flowing through the NTS, then the supply from Morecambe is curtailed to manageable levels.

- The system operator or relevant GDN could play a ‘backstop’ safety role in relation to hydrogen producers connected to their network. This would involve monitoring the hydrogen blend across their network, and curtailing producers where necessary for safety reasons (e.g. if producers have breached the injection blend constraint). Curtailment could be through direct contact with the producer in question, or using remote disconnection valves if immediate intervention is required.
- There may be value (for example to plant operators and from an environmental perspective) in a regulatory incentive which could be introduced as part of this solution package, encouraging the system operator and GDNs to manage gas flows to maximise hydrogen injections where possible (e.g. by flowing more methane past hydrogen entry points). For example, this could be a reputational incentive requiring the system operator and GDNs to publish how often and to what extent hydrogen producers had to be curtailed.

- **Solution package 2: injection constraints with impact assessment.**

  This solution package builds on the first, with the addition of a pre-connection impact assessment by the relevant network operator to determine whether a hydrogen producer should be allowed to connect in a given location.

  All applications for connections to the grid (both NTS and LTS) currently undergo an evaluation before they are able to connect. Under this solution package, an enhanced evaluation would take place for prospective hydrogen producers, assessing their likely ability to inject, and more importantly the likely impact of their connection on the ability of other hydrogen producers to inject (e.g. if they are likely to saturate the gas in a given location, limiting the ability for producers downstream to inject). The evaluation could also assess their likely impact on users with specific requirements.

  If the potential impact is found to be significant, then an alternative location for the connection would need to be found. This might require change to the existing framework (for example a policy change that explicitly allows networks to turn down a connection, which would then be embodied in the legislation and/or licence conditions), which currently does not allow networks to deny connection terms to applicants.

This impact assessment would need to involve collaboration between the National Grid SO and the GDNs to share necessary information to assess whole system impacts. This is discussed further in section 4.

- **Solution package 3: injection constraints, impact assessment and Last-In-First-Out.**

  This solution package builds further on the second, requiring the system operator to take a more active role in cases where the blend constraint is reached to ensure that producers connected last are constrained first (to create more certainty for early investors that their ability to produce will not be impacted by developments on the network after their investment decision). We note that these cases are likely to be rare under baseline circumstances, and particularly given the use of an impact assessment before connecting hydrogen producers.

Assessment

The key trade-offs between these three packages relate to efficiency and system operation costs.

- Solution packages 2 and 3 are likely to result in a more **efficient use of network capacity** than solution 1. Under package 1, hydrogen producers may seek to avoid the risk that producers connecting after them may limit their ability to inject hydrogen by choosing to connect in locations where this is less likely to happen (but which may be higher cost), or requiring higher support payments to compensate for this risk. Packages 2 and 3 help to mitigate this potential inefficiency, although we note that neither package would remove it entirely.
- In terms of **system operation costs**, solution packages 1 and 2 involve a relatively limited 'backstop' role for the system operator or GDN, comprising monitoring and occasional intervention if required. System operation costs under solution package 3 will be higher, given the need for more active intervention during times of constraints, to implement Last-In-First-Out. However, such incremental system operation cost is likely to be fairly limited given that these constraints are not expected to occur frequently under baseline circumstances.

In addition to these trade-offs, we have also considered **path dependency issues**, i.e. how future scenarios might affect the choice of solution in the near term. In future scenarios where the blend limit is frequently reached, a different approach to managing blend and ensuring economic dispatch of hydrogen plants could be beneficial. For example, a market-based approach to curtailment when the blending limit is reached, or arbitrage of hydrogen capacity by the system operator are potential options. Implementing solution package 3 in the near term may risk creating rights or expectations among early hydrogen producers that their ability to inject will always be protected through the Last-In-First-Out approach, which could limit options in the future that do not maintain those rights/expectations.

Finally, we note that policy direction provided by government may impact the weighing up of solution packages, for example by providing guidance on how active a role networks should play in determining where hydrogen producers connect to the grid.

Recommendation

We recommend that solution package 2 is implemented in the near term. Compared to package 1, the addition of the impact assessment is likely to bring benefits for a relatively limited incremental cost. The additional cost and complexity of the Last-In-First-Out measures in package 3 are not likely to bring sufficient benefits in efficiency of use of network capacity, and could create expectations or rights that may limit options in the longer term.

BOX 4: LEARNINGS FROM THE DSO TRANSITION IN ELECTRICITY

As the transition to a low carbon energy system progresses, increasing uptake of new technologies and tools such as Demand Side Response (DSR) have made it possible for DNOs to take a more active approach to managing constraints and balancing their networks, beyond the traditional approach of simply increasing capacity in response to network constraints. This transition from the traditional electricity DNO role to a more active distribution system operator (DSO) role has raised questions around the roles and responsibilities of the DSOs. The ENA has considered this question in its 'Future Worlds' consultation,[39] which set out five possible scenarios around system operation responsibilities. These scenarios range from a world where the DSO acts as the neutral market facilitator for all distributed generation and provides services on a locational basis to ESO, to a world where a new entity plays this role, providing efficient services to the DNO and/or DSO as required.

There are parallels between the question of the DSO role and the future role of the GDN in a hydrogen blended gas system. In the near term we have not proposed any significant changes in the GDN role, beyond what is required to connect hydrogen producers, conduct impact assessments and act as a backstop. However in the longer term, if more complex system operation solutions are implemented to manage hydrogen connections and blend, it may be necessary to further consider how system operation responsibilities are allocated and coordinated between GDNs, the SO and other parties, building on learnings from the debate in electricity where relevant.

3.3.2 Solution packages for transmission charges

We consider two options for adapting transmission charges (i.e. connection charges and capacity and/or commodity charges applied at entry).

- **Solution package 1**: Retaining the status quo (i.e. shallow entry connection charge and postage stamp network prices at entry[40]).

[39] ENA (2018), Future Worlds, https://www.energynetworks.org/assets/files/14969_ENA_FutureWorlds_AW06_INT.pdf

[40] We note that the postage stamp price at entry is a reserve price (i.e. the auction floor price for a specific entry/exit point and NTS user). If an NTS user triggers reinforcement costs, it may be required to pay a price above the reserve price.

- **Solution package 2**: Adjusting the connection boundary to a deep entry connection charge[41].

Assessment

When applying the assessment criteria set out in section 3.1.1 to assess the solution packages on network charges, we also take into account the UNC objectives (see annex B). Specifically, our assessment against the 'efficiency' criterion reflects UNC objectives of cost-reflectivity and effective competition. A charging regime that is cost-reflective and does not cause distortions in competition will also create incentives for the efficient use and development of network capacity.

The key trade-off between the two solution packages on transmission charges relates to efficiency and ease of implementation.

- Solution package 2 may lead to **efficiency** gains, compared to solution package 1 (i.e. the status quo), by providing locational signals in relation to network investment via the connection charges. However, the potential efficiency gains are likely to be small in the baseline circumstances, since according to Ofgem the NTS is largely operating below capacity with demand expected to decline.[42] In addition, there are some downsides associated with sending locational signals via a deep connection charge, as outlined in section 3.2.
- In terms of **feasibility and practicality**, solution package 2 will require time and resources to implement, whereas solution package 1 retains the status quo framework. Solution package 2 may also lead to increased ongoing administrative costs and complexity for networks, compared to solution package 1 (i.e. because the network will need to estimate the reinforcement cost for each new entry connection).

In addition to these trade-offs, we have also considered **path dependency issues**. In future scenarios where the NTS has significant capacity constraints and a large number of new connections, an alternative charging system might be more appropriate. For instance, a return to entry capacity charges based on the forward-looking long run marginal cost (LRMC) of additional capacity may be appropriate. Implementing solution package 2 in the near term may lead to transitional issues if a marginal cost based entry capacity charge is needed in the future, for example to ensure that existing entry connections are not effectively charged twice for grid reinforcement (i.e. first through the deep connection charge, and then through new network pricing charges at entry).

Recommendation

We recommend that the status quo charging arrangements (i.e. solution package 1) is retained. Since the potential gains from efficiency from solution package 2 are

[41] We note that if this solution package is implemented, it will require some changes to the methodology for charging for additional reinforcement costs via network prices to ensure that these costs are not charged twice to NTS users.

[42] Ofgem (2020), Uniform Network Code (UNC) Modification (UNC678A): Gas Transmission Charging Regime, https://www.ofgem.gov.uk/system/files/docs/2020/05/unc678_-_decision_0.pdf, page 24.

unlikely to be material, the effort associated with change is likely to be disproportionate.

3.3.3 Solution packages for distribution charges

We consider three options for adapting distribution charges (i.e. connection charges and network prices).

- **Solution package 1**: Retaining the status quo (i.e. deep entry connection charge and LDZ SECC applied at entry).
- **Solution package 2**: Retaining a deep entry connection charge, but adjusting the LDZ SECC to:
  - remove credits relating to cost recovery components of charges;
  - reflect the different CVs of methane and hydrogen injections; and
  - reflect any additional costs/benefits of injections into the distribution network.
- **Solution package 3**: Adjusting the connection boundary to a shallow connection boundary and replacing the LDZ SECC with an LRMC-based entry capacity charge.[43]

Assessment

Similarly to above, we reflect UNC's objectives of cost-reflectivity and effective competition in our interpretation of the 'efficiency' criterion.

The key trade-off between the solution packages relates to efficiency and ease of implementation.

- In terms of **efficiency**, both solution packages 2 and 3 should result in efficiency gains compared to solution package 1 (i.e. the status quo). As explained in section 3.2, the credit elements of the LDZ SECC as currently defined are not cost-reflective and hinder effective competition. As such, these elements can create distortions which will be more material if there is a large number of hydrogen or biomethane producers connecting to the network. Solution package 3 may lead to further efficiency gains compared to solution package 2, as it adopts a shallow connection charge and therefore, avoids some of the downsides of the deep connection charge (see section 3.2).[44]
- In terms of **feasibility and practicality**, both solution packages 2 and 3 are likely to take a long time to design and implement, with high associated resource costs across the industry. Solution packages 1 and 2 may involve higher administrative costs and complexity for the networks compared to solution package 3, as the deep connection regime implies the need to estimate the reinforcement cost for each new entry connection.

[43] This entry capacity charge could also reflect the different CV of methane and hydrogen and reflect any additional costs/benefits of injections into the distribution network.

[44] We note that the potential efficiency gains under solution package 3 will depend on whether the charges are able to send accurate signals. It may be difficult to predict future utilisation of the network, which may mean that signals may not always incentivise efficient behaviour.

We have also considered **path dependency issues**. Similarly to the transmission charges, a future system might involve a shallow connection regime and an entry capacity charge based on LRMC. Since solution packages 1 and 2 retain the deep connection boundary, these options may lead to some future transitional issues. Solution package 3 involves a shallow connection boundary and an entry capacity charge based on LRMC and is therefore in line with a potential future solution. We note that solution package 3 might involve some near-term transitional issues, but these are likely to be easier to resolve as there is a small number of existing distribution entry connections.

Recommendation

Based on the above evaluation, solution package 3 appears likely to be preferable in the near-term. However, we note that such a change will take time and effort. The decision will ultimately depend on the magnitude of expected efficiency gains and this should therefore be tested further as more information becomes available as to the likely scale of distribution connections by hydrogen and biomethane producers in the near term.

3.3.4 Solution packages for level playing field between entry connections

We considered three options for ensuring a level playing field between facilities connected at the transmission and distribution network level.

- **Solution package 1**: Retaining the status quo (i.e. no common charging methodology for entry connections across GDNs and an inconsistent connection boundary between transmission and distribution networks).
- **Solution package 2**: Implementing a common charging methodology for entry connections across gas distribution networks.
- **Solution package 3**: Implementing a common charging methodology for connections across gas distribution networks (as in solution package 2) and also applying a consistent connection boundary across the distribution and transmission networks.

There is an interdependency between these solution packages and the solution packages for adapting transmission and distribution connection and network charging regimes. For instance, the connection charging boundary between the transmission and distribution networks will need to be consistent with the approach for cost reflective connection charges. We consider these interdependencies as part of our assessment.

Assessment

The key trade-off between the solution packages relates to efficiency and ease of implementation considerations.

- In terms of **efficiency**, solution package 1 (i.e. the status quo) does not ensure a level playing field for entry connections due to the lack of a common charging methodology across GDNs and the lack of consistency in the transmission and distribution network connection boundary. As discussed in section 3.3.3, this could distort producers' incentives to connect to either the transmission or distribution network, or between different GDNs and therefore will hinder effective competition between entry injections. Solution package 2 deals only with the GDN issue, while solution package 3 addresses both. The choice between them will depend on expectations about the number and size of production facilities likely to connect at the distribution and transmission level.

- In terms of **feasibility and practicality**, both solution packages 2 and 3 will take time and come with a high resource cost. Clearly solution package 3 will take the most time and incur the greatest cost, as it also requires a change in the connection boundary at entry.

Recommendations

In sections 3.3.2 and 3.3.3 we recommend the status quo solution package for transmission charges and a change of the existing distribution charges for the distribution networks (i.e. solution package 3 in section 3.3.3). We note that these decisions should be tested further as more information becomes available as to the likely scale of distribution and transmission connections by hydrogen and biomethane producers in the near term.

These recommendations on the distribution and transmission charges will result in a consistent connection boundary for entry connections (i.e. shallow connection boundary) across the distribution and transmission networks. Therefore, the only additional question to consider is whether to implement a common charging methodology for entry connections across the GDNs.

We recommend adopting a consistent common charging methodology for entry connections (e.g. in relation to ownership of entry equipment) across the GDNs as it will facilitate effective competition between network users connected at different networks. However, we note that such a change will take time and effort. The decision will ultimately depend on the magnitude of expected efficiency gains and this should therefore be tested further as more information becomes available as to the likely scale and locations of distribution connections by hydrogen and biomethane producers in the near term.

4 ROADMAP TO ENABLE HYDROGEN BLENDING

In this section we set out a roadmap of the commercial and regulatory actions that need to take place to implement the solutions to enable hydrogen blending that we set out in the previous section.

4.1 Scope and approach

Scope

The aim of the roadmap is to identify areas where investigation or change to the existing commercial framework is required in order to allow hydrogen producers to connect and inject hydrogen into the grid. Our focus is on enabling hydrogen blending under the baseline circumstances that we set out in section 2.2.

At a high level, actions in the roadmap will cover:

- further work to be carried out by the industry to confirm the preferred solutions set out in section 3.3;
- areas where specific input is required from technical studies; and
- actions by government, Ofgem, networks and others to implement the preferred solutions (including changes to legislation, licences and codes).

It is important to note at the outset that the aim of the roadmap is not to set out detailed actions. Rather, it provides a high-level plan of the key areas of work that industry will need to take forward and identifies the groups best placed to do this.

Phasing of roadmap actions

We focus on the actions that fall within our first two suggested stages for the development of a framework for hydrogen blending.

- Preparation stage: actions required to enable a small number of hydrogen producers to connect. Because we assume that the first few producers to connect can be treated in a bespoke fashion, for example with restrictions on where they are able to connect and with site-specific conditions, the focus at this stage is on making the necessary changes to allow hydrogen to enter the grid.
- Standardisation stage: actions for developing a standardised and more comprehensive framework for hydrogen blending, which can accommodate the full range of production facilities. This stage will also need to consider coordination with the work that is being done to standardise the treatment of green gases, such as biomethane.

While these two phases of work could be carried out sequentially (i.e. only starting the actions in the standardisation stage once the first hydrogen producers connect), it is likely to be desirable to start some of the actions for standardisation sooner than this, meaning that the two stages would overlap. This is reflected in the roadmap illustrated in section 1.2.

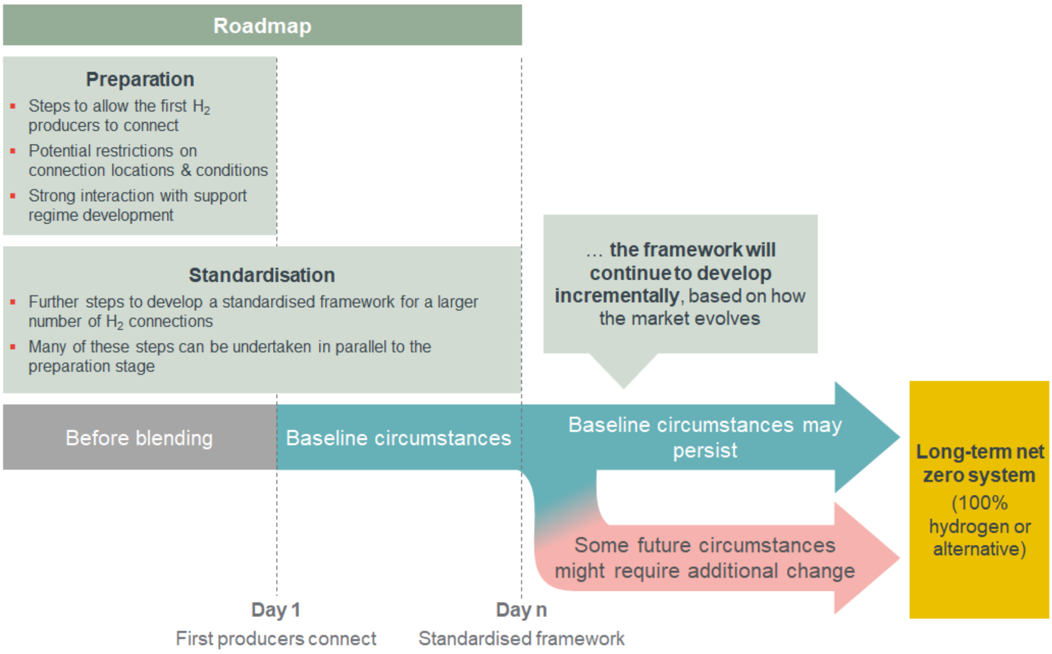
To enable the industry to start work on the roadmap, there are some immediate next steps that BEIS and Ofgem can take. One of these steps is for BEIS to form, and Ofgem to subsequently lead, an overarching delivery group that would oversee and coordinate the various actions in the roadmap. This would help ensure that work progresses in a timely manner and that responsibilities and deliverables are centrally coordinated. This and other immediate actions for BEIS and Ofgem are discussed further in our conclusions and next steps section (see section 5).

We expect that industry-driven code and licence modification processes will be key tools in the implementation of a standardised framework for hydrogen blending. This will also be the case for the subsequent incremental changes required to the framework as circumstances evolve. This continued evolution of the framework is not covered in the roadmap as it will be shaped by how the market for hydrogen blending develops; for example the size and geographical distribution of production facilities. Factors that will be important in determining this evolution will include whether producers want to connect at NTS or distribution level; how quickly the hydrogen blend in the grid approaches the cap; and whether hydrogen blending appears to be a relatively brief transitional phenomenon, or present for a longer period of time as part of the movement to a net zero system.

This process is in line with the experience of introducing biomethane into the grid. Early biomethane producers were able to connect to the grid with bespoke agreements and through securing exemptions from certain requirements (e.g. biomethane producers have a class exemption from oxygen content requirements in GS(M)R, as well as from gas transporter licence requirements). Over recent years the industry has been working on standardising the frameworks around biomethane (in Annex B we set out the developments of the commercial framework for biomethane producers).

The different phases of the roadmap are illustrated in Figure 12 below.

Figure 12 Approach to roadmap



Source: Frontier Economics

In the sub-sections below, we set out the actions that the gas industry and government will need to take to enable hydrogen blending, covering the preparation and standardisation stages in turn.

For each of the actions in the roadmap, we set out the following:

- **Who:** we identify the key group or groups that will be most likely to lead work in this area. In most cases this will include:
  - Government (BEIS);
  - Ofgem;
  - the gas network operators; or
  - Xoserve.

  We note that for a number of the actions, there may be some ambiguity as to which group will lead the work, as there could be different options for taking the action forward (for example, there is an option involving a choice between an Ofgem-driven Significant Code Review (SCR) and a set of industry-driven code modifications).

  It is clear that a large number of additional stakeholders (including but not limited to hydrogen producers, shippers, suppliers, gas users, industry bodies and academics) will need to be involved in many of the actions set out in the roadmap. However, the aim at this point is to identify a group that can take responsibility for taking forward a given action, and involve and coordinate other stakeholders as needed.

- **How long:** we provide a rough indication of how long each action is likely to take. We take a central view (i.e. neither optimistic nor pessimistic) on the length of time of each action on the basis of input from our functional group and stakeholder engagement and/or desk research (e.g. looking at industry precedent on amending the commercial framework). The timeline reflects the number of years from the point that the industry decides to take this forward. As such, we do not provide a date for the completion of the preparation and standardisation stages.

We note that the actual duration of each action and the overall length of the preparation and standardisation stages are highly uncertain, since they will depend on the issues that arise, how quickly inputs can be collected from relevant stakeholders and how quickly the necessary processes are initiated. There are also factors other than those relating to adapting the commercial framework that can have an impact on the timings; for example the development of hydrogen production technologies and the completion of studies into the technical and safety aspects of hydrogen blending. The estimates provided should therefore be viewed as indicative and subject to refinement as each work area is taken forward.

- **Interdependencies and sequencing:** some actions in the roadmap will be dependent on outputs and findings from other actions, or will benefit from being coordinated with other areas of work. We illustrate the appropriate sequencing of actions in the roadmap, and we flag areas that may need coordination. We note in particular that a number of actions in the standardisation stage could be coordinated or combined with similar work that needs to be undertaken for biomethane. Coordinating across related hydrogen and biomethane work can help to use time and resources more efficiently, as well as deliver consistent frameworks across the two.

Roadmap guiding principles

Recent experiences in the gas industry have provided learnings that are directly relevant for enabling hydrogen blending, and which we have used as guiding principles in developing the roadmap set out in the following sections. In particular, the challenges of integration of biomethane into the gas commercial framework have provided insights and learnings that can now be used to improve the process of enabling hydrogen blending. We set out the key learnings below.

- **Transparency and collaboration from the outset.** Networks, Ofgem and other stakeholders should work together to develop consistent frameworks and approaches. Working independently of each other and developing approaches in isolation can lead to distortions and the need for further change down the line to achieve a common approach. There should also be transparency with the wider industry, with proposals put to consultation where they will impact other stakeholders. This will mean potential issues can be identified and addressed in good time.
- **Timeliness.** Where possible, work should be started at an early stage. Better ‘in principle’ solutions can often be reached if thinking has begun before specific projects are on the table. The risk of addressing issues at very short notice to enable a specific connection is that the resulting solutions may be highly tailored to that project, and may not work for others. However, this does not necessarily mean that final decisions need to be taken early (see next point).

- **Innovation and agility.** While it is important to have consistency and a clear framework, it is also important to leave room to build innovation and learnings into that framework. So in areas where there may be learnings from experiences with the first few producers, decisions might best be taken once those learnings can be captured.
- **Ongoing improvement.** Regardless of what framework is implemented initially, subsequent changes are likely to be needed. Where possible, frameworks should be implemented so that important future changes can be made quickly and transparently.

One example that illustrates some of these principles is the need to agree the division of ownership and responsibilities between networks and producers (e.g. ownership of entry point equipment, and responsibilities for designing and building that equipment). This process took a long time and required significant iteration for biomethane, with networks initially developing their own approaches before later agreeing a common approach.

In the case of hydrogen blending, addressing this issue collaboratively across all networks, both transmission and distribution, from the outset will help deliver a common approach, and putting this to consultation will ensure that the wider industry can feed into a final decision. Addressing the issue in a timely way will ensure that producers have clarity from an early stage, and that the solution is robust enough to work across different situations, rather than tailored to the needs of the first producers connecting to the grid.

4.2 Preparation: actions to enable the first hydrogen connections

As described above, the preparation stage is the period of time leading up to the connection of the first few hydrogen producers to the grid. At this stage, actions will focus mainly on:

- securing exemptions from or making necessary changes to regulations, codes and licences to allow material quantities of hydrogen to be injected into the grid;
- developing initial (potentially bespoke) connection agreements between networks and hydrogen producers; and
- developing and installing equipment necessary to ensure safety.

In the sub-sections below we provide more detail on the actions that will need to be completed in the preparation stage of the roadmap in order to ensure that the investment decisions of the first few hydrogen producers can be made as early as possible.

The sequencing of the actions at the preparation stage reflects the following constraints:

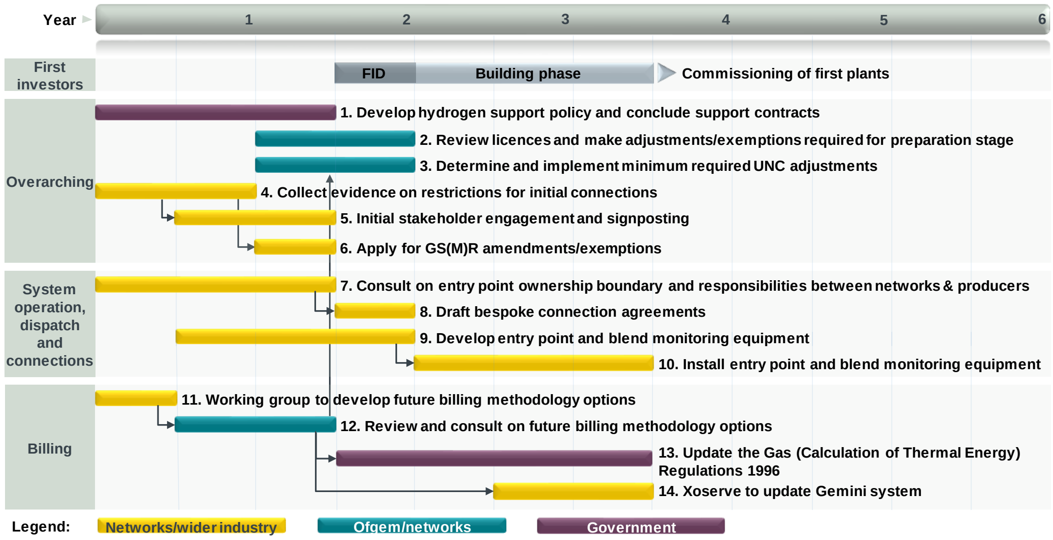
- Interactions with the investment decisions of the first few hydrogen plants. We set out the actions that need to be undertaken before the first few hydrogen investors can make a final investment decision (FID) and the actions that can be completed after or in parallel to FID and the building stage of the first hydrogen plants.

- Dependencies with other actions, i.e. taking into account that the outputs of some actions are an input to other actions and that, therefore, the sequencing of actions needs to reflect that.

We note that some of these actions are low-regret and so could be initiated earlier if the resource is available. We describe these in section 5.

The roadmap of the preparation stage is shown in Figure 13. The numbering of each of the actions in the sub-sections below reflects the numbering of each of the actions in the roadmap illustration. A footnote is provided in the heading for each action, setting out the source of the action, whether through engagement with stakeholders, or through the issues and recommended solution packages identified in the course of our work.

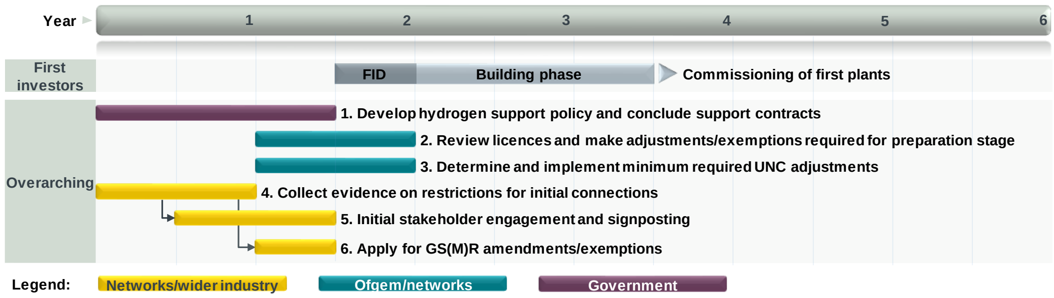
Figure 13 Roadmap – preparation stage



Source: Frontier Economics

4.2.1 Overarching actions

Figure 14 Preparation stage: overarching actions



Source: Frontier Economics

1. Develop hydrogen support policy and conclude support contract[45]

The government will need to introduce funding arrangements to support low-carbon hydrogen production.[46] It is important that a hydrogen support policy is in place early on in the process, and before the FID of the first few hydrogen plants, in order to provide investors with a clear framework for investment.

The form of the support mechanism may determine the size of plants, the pressure tier they choose to connect at, and when they inject into the grid. For early producers, it may be reasonable to expect support mechanisms to be sufficiently tailored to ensure that the choices made by those producers (for example, around where to locate and when to inject into the grid) work in harmony with the commercial framework to minimise the impact of distortions.

We expect the process of developing the hydrogen support policy and concluding support contracts could take about 18 months.[47]

2. Review licences and make adjustments/exemptions required for preparation stage[48]

A review of licence conditions for gas transporters, shippers and suppliers is required, to determine whether any conditions need to be amended to enable hydrogen blending.

If this review finds that any licence changes need to be made immediately at the preparation stage (e.g. if they would be contravened by blending any amount of hydrogen into the grid), exemptions or modifications will need to be made.

We expect that investors will require at least some progress on this action before the FID of the first hydrogen plants, which is the reason for the timing of this action in the roadmap. We expect the process of reviewing licences and making a few modifications (of moderate scale) and/or exemptions could take around a year.

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45 As confirmed through the stakeholder engagement process, this action will be required to enable hydrogen production.

46 We note that BEIS's consultation on the key aspects of policy design to support biomethane production invited views on what mechanisms might be appropriate for long-term support of alternative sources of green gas, such as hydrogen blending, in the future. See BEIS (April 2020), *Future support for low carbon heat*, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/888736/future-support-for-low-carbon-heat-consultation.pdf. Frontier Economics was commissioned by BEIS to develop business models to support low carbon hydrogen production. See Frontier Economics (August 2020), Business models for low carbon hydrogen production, https://www.frontier-economics.com/media/4157/business-models-for-low-carbon-hydrogen-production.pdf.

47 We note that precedent supports a longer time period for developing support policies for renewable producers. For instance, the introduction of the non-domestic RHI took around 36 months (between the introduction of the Energy Act (2008) and the introduction of the support scheme in November 2011). We assume a shorter time period for this action because it only involves initial hydrogen support contracts and further work to refine this policy will be carried out under action 14 of the standardisation stage.

48 As confirmed through the stakeholder engagement process, this action will be required to introduce hydrogen blending.

3. Determine and implement minimum required UNC adjustments[49]

A high-level review of the UNC should be carried out to determine whether any initial changes are needed to enable hydrogen to be injected into the grid. For example, the definition of gas may need to be updated (it currently refers primarily to methane), and there may be some minor changes needed in relation to billing arrangements that could feed from action 12.

Again, we expect that investors will require at least some progress on this action before the FID of the first hydrogen plants. We expect this process could take about a year.

4. Collect evidence on restrictions for initial connections, e.g. locations suitable for GS(M)R exemptions and international issues[50]

It is likely that there will need to be restrictions in grid location for the first hydrogen producers. This is because networks and producers will need to demonstrate that the impact of the connection on end users will be limited before being granted exemptions from current gas specification regulations (see action 6). It will also be important to restrict connections to locations where they will not impact international flows, until any international issues can be identified and resolved during the standardisation stage.

Network operators will therefore need to assess where on their networks initial hydrogen producers can connect without causing issues for end users, and where the necessary criteria to obtain required exemptions can be met. Networks are likely to be expected to publish this information for developers.

There may also need to be other restrictions for initial connections, for example around gas quality, flow rates or total volumes of hydrogen injected. These will also need to be established.

The timing of this action is driven by the need to secure any GS(M)R exemptions before early investors are able to take a FID, and the need to complete this action before those exemptions can be applied for. We expect this process could take about 18 months.

5. Initial stakeholder engagement and signposting[51]

As described above, the preparation stage is likely to involve restrictions on where hydrogen producers are able to connect, and site-specific conditions. However, it is important that hydrogen investors understand what type of restrictions are likely to apply, as well as how and when treatment is likely to become more standardised. This will help ensure that investors have visibility of the commercial conditions they will face when developing their projects.

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49 As confirmed through the stakeholder engagement process, this action will be required to introduce hydrogen blending.

50 As confirmed through the stakeholder engagement process, this action is required in order to enable initial hydrogen producers to connect to the grid before the recommended solution package for system operation, dispatch and connections described in section 3.3.1 is implemented in the standardisation stage.

51 As confirmed through the stakeholder engagement process, this action will be required to introduce hydrogen blending.

Once networks have completed action 4 and have a good understanding of what restrictions are likely to apply to early developers, this action involves networks engaging with investors to communicate these restrictions, as well as signposting how, and approximately when, these restrictions are likely to be lifted.

6. Apply for GS(M)R amendments/exemptions[52]

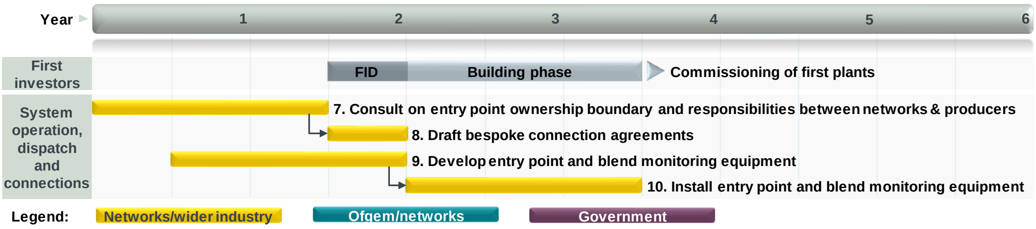
The Gas Safety (Management) Regulations 1996 (GS(M)R) is a statutory instrument that sets out the responsibilities of network operators with respect to gas safety. It also sets out the content and characteristics of gas that can be transported in the gas grid. The current regulations limit hydrogen content to a level of 0.1%, and contain other requirements that may not be compatible with material amounts of hydrogen entering the grid.[53]

It will be necessary to amend these requirements to enable hydrogen blending. However, if amendments are not possible during the preparation stage, exemptions from these requirements would be a suitable short-term solution during the preparation stage to enable initial hydrogen connections. Networks will need to apply to the Health and Safety Executive (HSE) to obtain exemptions.

The timing of this action is driven by the need to secure any GS(M)R exemptions before early investors are able to take a FID. We expect this process could take about six months.

4.2.2 Actions related to system operation, dispatch and connections

Figure 15 Preparation stage: actions related to system operation, dispatch and connections



Source: Frontier Economics

7. Consult on entry point ownership boundary and responsibilities between networks and producers[54]

A key learning from the experience of introducing biomethane into the grid was that there were a number of areas where division of responsibilities and ownership needed to be agreed between distribution networks and producers.

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52 As confirmed through the stakeholder engagement process, this action is required in order to enable initial hydrogen producers to connect to the grid before the recommended solution package for system operation, dispatch and connections described in section 3.3.1 is implemented in the standardisation stage.

53 http://www.legislation.gov.uk/uksi/1996/551/made.

54 As confirmed through the stakeholder engagement process, this action will be required to introduce hydrogen blending.

In particular, ownership and operation of various pieces of entry point equipment needed to be decided. In some cases it was judged more efficient for networks to contract out certain responsibilities to producers.

Before initial hydrogen connections can be made, an approach to ownership and responsibilities should be proposed by networks, and then consulted on with the wider industry. Ideally the chosen approach would be broadly consistent with the approach currently used for biomethane connections. The approach should also take into consideration the potential benefits of allowing competition and choice in certain roles, such as building certain parts of the connection assets.

The timing of this action is driven by the need for hydrogen investors to understand their responsibilities ahead of taking a FID. We expect this process could take about 18 months.

8. Draft bespoke connection agreements[55]

Once proposals for boundaries of ownership and responsibilities between networks and producers have been agreed through action 7, networks can start drafting connection agreements. At this stage these would likely be bespoke, reflecting any restrictions identified in action 4 above, and possibly the individual circumstances of producers. Again, we would expect investors would require at least some progress on these agreements prior to taking FID.

We expect this process could take about six months.

9. Develop entry point and blend monitoring equipment[56]

Existing entry point equipment is likely to need to be adapted to work with hydrogen, for example in order to measure energy content and gas quality accurately. Network equipment may also need to be developed to monitor hydrogen blend at key points in the grid.

IT systems may also need to be updated to be able to monitor hydrogen connections.

For network operators to be able to meet their safety obligations, it is essential that this equipment is developed and installed ahead of any hydrogen being injected into the grid. Therefore the timing of this action is driven by the need to complete this development step ahead of installation, which in turn needs to be completed before the first hydrogen plants are commissioned.

We expect this process could take about 18 months.

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[55] As confirmed through the stakeholder engagement process, this action is required in order to enable initial hydrogen producers to connect to the grid before the recommended solution package for system operation, dispatch and connections described in section 3.3.1 is implemented in the standardisation stage.

[56] This action is required in order to implement the recommended solution package for system operation, dispatch and connections described in section 3.3.1.

10. Install entry point and blend monitoring equipment[57]

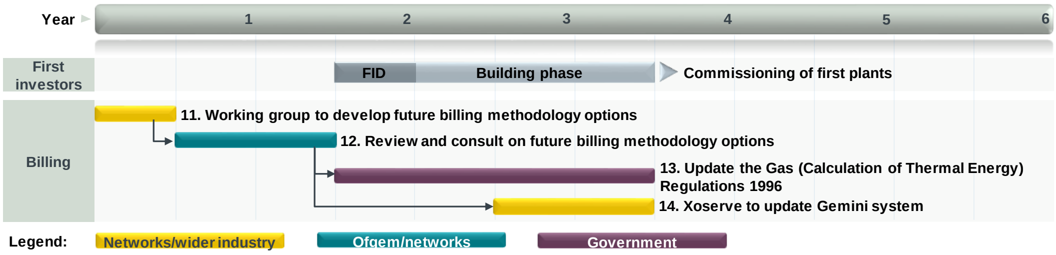
The entry point equipment described above will need to be installed, and this will in turn need to be coordinated with the overall programme to commission hydrogen production facilities and connect them to the grid. Other blend monitoring equipment on the network can be installed at any point before the first connections start injecting hydrogen.

Therefore the timing of this action is likely to run alongside the building of the first plants.

We expect this process could take about 18 months.

4.2.3 Actions related to billing

Figure 16 Preparation stage: other actions



Source: Frontier Economics

11. Working group to develop future billing methodology options

The current billing regime will need to be amended to enable hydrogen blending.[58]

The Future Billing Methodology is a Gas Network Innovation Competition (NIC) project undertaken by Cadent, which explores alternative options for the billing methodology to help integrate diverse gas sources (e.g. biomethane and hydrogen).[59] The project is expected to be completed in March 2021.[60]

Networks and suppliers will need a means of reviewing the outcomes of this study and providing advice on the way forward, including whether there are any gaps in the current studies that require further analysis to be undertaken. We suggest the establishment of a forum to discuss these topics.

The views expressed at the forum would be used as an input to the review and consultation on future billing methodology options (action 12 below). We expect

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[57] This action is required in order to implement the recommended solution package for system operation, dispatch and connections described in section 3.3.1.

[58] The current billing regime is based on a flow-weighted average calorific value (FWACV) approach. The FWACV is calculated from the flows and the CVs of all the gas entering a charging area. As a consumer protection measure, the FWACV is subject to a cap, i.e. the FWACV used for customer billing cannot exceed a value of 1.0 MJ/m³ above the lowest measured daily CV average of the inputs into the charging area. This means that an insignificant volume of low CV gas can cap an entire charging area and lead to under-billing of customers. This is currently addressed for biomethane by adding propane to enrich the gas to meet the target CV. See Ofgem, Future Billing Methodology: Project Summary, https://www.ofgem.gov.uk/ofgem-publications/107840.

[59] Ofgem, National Grid Gas Distribution – Future Billing Methodology, https://www.ofgem.gov.uk/system/files/docs/2017/02/16_dec_2016_master_nic_re-submission-final.pdf.

[60] https://futurebillingmethodology.co.uk/.

this process could take about six months. If significant gaps are identified that require further work by the industry, this stage will take longer.

12. Review and consult on future billing methodology options

Once the networks have agreed on the billing methodology options and appropriate way forward under action 11, Ofgem will need to review them, determine an appropriate way forward and set out what changes are required in the regulations to implement these. This action will need to happen before FID to provide confidence to investors on how the billing regime will be amended.

We consider that this process could take about a year.

13. Update the Gas (Calculation of Thermal Energy) Regulations 1996

The current billing methodology is predominantly derived from the Gas (Calculation of Thermal Energy) Regulations 1996[61] (and Amendments in 1997[62]). These regulations stipulate, inter alia, how the networks should calculate CV for billing purposes, and so they will need to be amended to address the issues with the current billing regime.

The type of change that is required will depend on the modified billing methodology regime identified as part of action 12 above, and therefore the updating of these regulations will need to follow after action 12.

This process could be lengthy (i.e. it could take around two years). This is because these regulations are a statutory instrument, which means that changes will need to go through a parliamentary approval process. However, past experience suggests that this process could be completed in a significantly shorter timeframe if suitably prioritised and well organised.

We note that modifications to these regulations may also require amendments to the UNC (for example, the Ofgem Directed CV measurement sites, which are set out in the UNC, might need to be amended to comply with the requirements in the Gas (Calculation of Thermal Energy) Regulations). These amendments will be made as part of action 3.

The process of amending the billing regime could be significantly simplified if the methodology for calculating the CV for billing purposes was removed from the scope of government regulations and instead incorporated into the UNC or other Ofgem regulations.

14. Xoserve to update Gemini system

If the billing regime changes, Xoserve may need to update the Gemini system. Whether this is required, and the scale of change to the Gemini system, depends on the billing methodology that is implemented.

If an update is required, we expect this process could take about a year.

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[61] The Gas (Calculation of Thermal Energy) Regulations 1996, http://www.legislation.gov.uk/uksi/1996/439/made.

[62] The Gas (Calculation of Thermal Energy) (Amendment) Regulations 1997, http://www.legislation.gov.uk/uksi/1997/937/made.

4.3 Standardisation: actions to establish a uniform framework for multiple hydrogen connections

At the standardisation stage, the focus of work will be on reducing restrictions and standardising the treatment of future hydrogen producers connecting to the grid. There are some opportunities at this stage to achieve common approaches with biomethane, and we highlight where this is the case. Actions will involve:

- making changes to licences, codes and agreements in order to establish a comprehensive and more permanent framework for hydrogen blending;
- building on learnings from experiences with the first few hydrogen producers, for example refining bespoke hydrogen connection agreements to develop standardised hydrogen connection agreements; and
- implementing the solution packages set out in section 3.3.

In the sub-sections below we provide more detail on the actions in the standardisation stage of the roadmap.

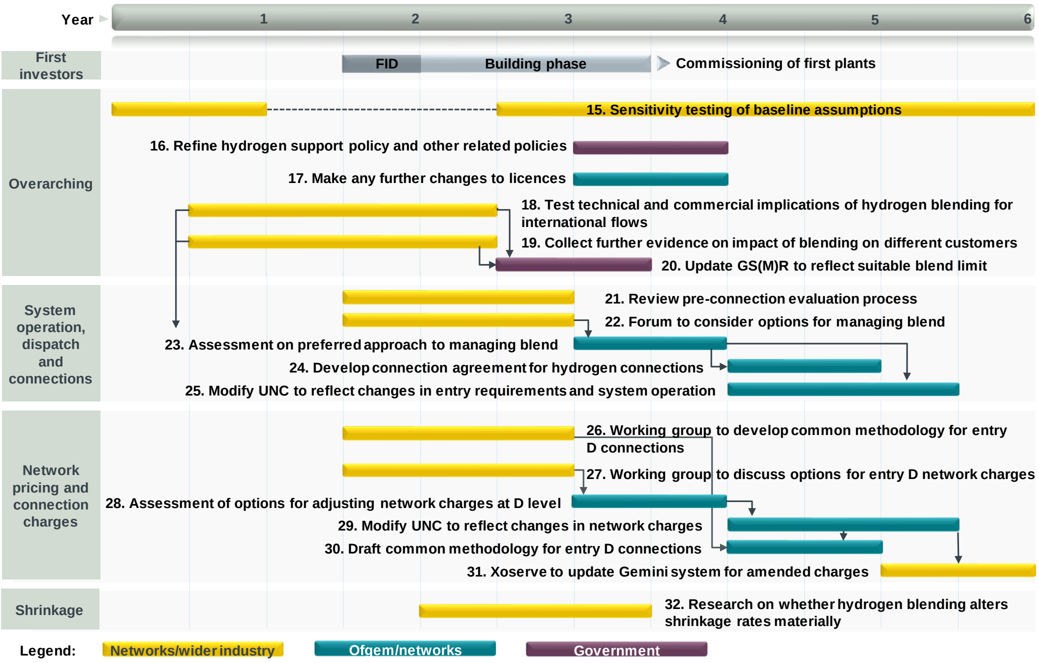
Our roadmap for the standardised framework sets out the timing of each action such that the standardised framework is introduced as soon as possible after the first few hydrogen producers connect. We note that it is possible that the industry considers that the standardised framework does not need to be developed this quickly (for example, were there to be a limited number of producers waiting to connect).

The sequencing of the actions at the standardisation stage reflects the following constraints:

- Dependencies on the first few hydrogen plants. Some of the actions under the standardisation stage can only be initiated after the FID or the building phase of the first few hydrogen plants, as they will draw on learnings from that process.
- Dependencies on other actions. As with the preparation stage, the roadmap takes into account the interdependencies between actions, i.e. when the output of one action is an input into another action.

This is illustrated in Figure 17.

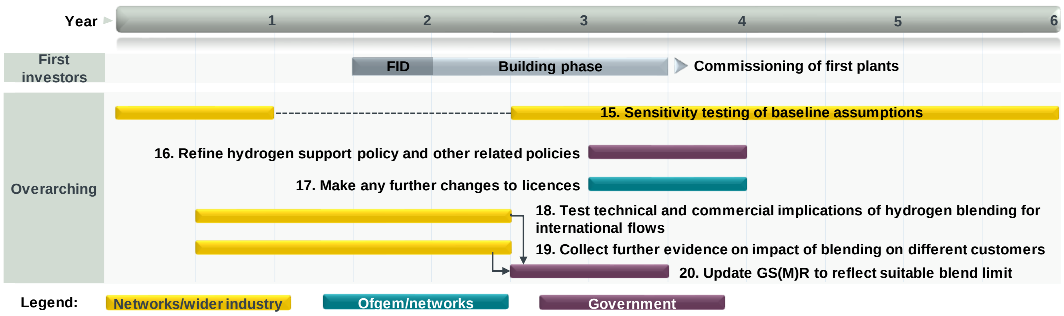
Figure 17 Roadmap – standardisation stage



Source: Frontier Economics

4.3.1 Overarching actions

Figure 18 Standardisation stage: overarching actions



Source: Frontier Economics

15. Sensitivity testing, monitoring and communication around baseline assumptions[63]

The recommended solutions for adapting the commercial regime are based on the baseline assumption that the number and location of hydrogen connections are such that the blending constraint is rarely reached as discussed in section 3.3.1.

Testing the robustness of this assumption may require analysis that looks at different scenarios for the type of producers that could apply for connections in the near term, and whether these scenarios are consistent with the assumption

[63] As confirmed through the stakeholder engagement process, this action will be required to introduce hydrogen blending.

of the blending constraint being rarely reached. Scenarios would cover variables including location, size and primary purpose (e.g. serving industrial demand or blending) of hydrogen plants. We expect this process could take about a year.

After the FID of the first few investors in hydrogen plants and once the pipeline of investments in hydrogen production facilities is clearer, we recommend that the networks undertake periodic monitoring (for example on a yearly basis) of the continued reasonableness of the baseline assumptions. This monitoring would be based on 'real-life' evidence of the hydrogen blend at different points in the grid, as well as the pipeline of producers that are applying or expected to apply for connections.

It is important for the networks to communicate the findings of their monitoring to the wider industry. This will ensure that if the hydrogen blending constraint begins to be reached more frequently in certain locations, or if a significant number of large producers are likely to connect, the industry can begin necessary discussions around whether and how the existing framework will need to change to accommodate this.

We recommend that this action is initiated early in the standardisation stage. This will ensure that there is sufficient time to make any necessary amendments to the roadmap for the standardisation stage, and further changes to the commercial framework if the analysis indicates that the baseline assumptions do not represent a realistic set of circumstances for the near term (for example, to incorporate elements of the solution packages under certain future circumstances discussed in Annex D).

16. Refine hydrogen support policy and other related policies[64]

Building on action 1 from the preparation stage, BEIS may need to further refine the hydrogen support policy and potentially other related policies.

This stage should follow after the building phase of the first few hydrogen plants (for example, to take into account learnings in relation to the actual costs of constructing the plants). The initial hydrogen support policy might also be further developed to minimise potential distortions arising when reducing the initial restrictions (e.g. in relation to location and when to inject) from the future hydrogen producers connecting to the grid.

We expect this process could take about a year.

17. Make any further changes to licences[65]

Building on action 2 from the preparation stage, any remaining changes required to create a more permanent framework for hydrogen blending could be carried out at this point.

We expect this process could take about a year.

64 As confirmed through the stakeholder engagement process, this action will be required to introduce hydrogen blending.

65 As confirmed through the stakeholder engagement process, this action will be required to introduce hydrogen blending.

18. Test technical and commercial implications of hydrogen blending for international flows[66]

Further work is required to assess the technical and commercial impact of hydrogen blending for international flows, to identify the amendments required to address potential issues.

We expect this process could take about 18 months.

19. Collect further evidence on impact of blending on different customers[67]

In order to establish a standardised framework for multiple hydrogen producers to connect to the grid, a key step will be to amend GS(M)R to allow material quantities of hydrogen to be injected into the grid.[68] This process will require establishing exactly what level and quality of hydrogen is safe and acceptable to end users. The HyDeploy project is establishing this for domestic end users, but further work will be needed to establish the parameters that are acceptable to others, such as industrial users.

The timing of this action is driven by the need for findings to feed into action 20, which in turn may drive decisions around the exact system operation solutions adopted. We expect this process could take about two years, due to the potential need for one or more technical studies.

20. Update GS(M)R to reflect suitable blend limit[69]

Once the parameters for safe and acceptable levels of hydrogen blending have been established through action 19, GS(M)R will need to be amended to reflect this. This dependency is the key driver of the timing of this action.

GS(M)R is a statutory instrument, meaning that changes will need to go through a parliamentary approval process. We expect this process could take about a year. However, we note that there is currently an IGEM working group looking at producing a new gas quality standard that would replace some sections of GS(M)R.[70] This proposed standard would be more dynamic and flexible, but the HSE and government would still have powers to veto any changes to the standard. If the new standard is implemented soon enough, it could significantly reduce the time required to modify the relevant requirements.

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[66] As confirmed through the stakeholder engagement process, this action will be required to introduce hydrogen blending.

[67] As confirmed through the stakeholder engagement process, this action will be required to introduce hydrogen blending.

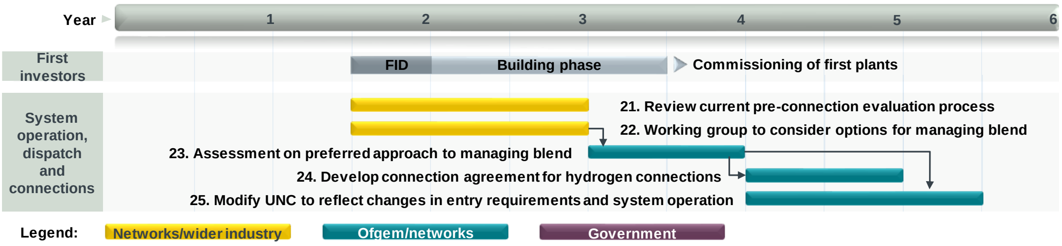
[68] See action 6 above for more detail on GS(M)R.

[69] This action is required in order to implement the recommended solution package for system operation, dispatch and connections described in section 3.3.13.3.1.

[70] https://www.igem.org.uk/technical-services/gas-quality-working-group/.

4.3.2 Actions related to system operation, dispatch and connections

Figure 19 Standardisation stage: actions related to system operation, dispatch and connections



Source: Frontier Economics

21. Review pre-connection evaluation process[71]

An important feature of the recommended solution package for system operation, dispatch and connections (see section 3.3.1) is that hydrogen producers are connected to the grid subject to an evaluation by the National Grid SO (for NTS connections) or the relevant GDN (for distribution network connections).[72] Although under baseline conditions the blending cap is only expected to be reached infrequently, if producers cluster close together in areas with limited demand, or if significant quantities of hydrogen are injected near users with specific requirements, hydrogen producers may need to be constrained more frequently. Therefore the SO or GDN would conduct an evaluation to assess the likely impact of a connection on other users.

To implement a suitable evaluation process, networks will need to review existing evaluation processes (the relevant parts of the Planning and Advanced Reservation of Capacity Agreement (PARCA) process used by National Grid, and the process used by GDNs to evaluate biomethane connection applications) to determine whether they provide sufficient information to be used for hydrogen connection applications. It may also be necessary, as part of the future evaluation, for National Grid and GDNs to share information about hydrogen producers on their own grids, so impacts across the whole grid can be understood.

The output of this review would be a plan to develop an evaluation process for hydrogen (ideally consistent with existing processes for NTS and biomethane connections), setting out additional information that would need to be collected, and how networks would share information where necessary. Ideally any changes to the evaluation process for distribution networks would be made broadly consistent with the approach to evaluating biomethane connections.

We expect this process could take about a year. The output of this action will feed into the assessment on the preferred approach to managing blend (action

[71] This action is required in order to implement the recommended solution package for system operation, dispatch and connections described in section 3.3.1.

[72] Networks currently have a requirement to offer terms of connection to all applicants. The current framework might therefore need to change to allow hydrogen connections to be conditional on an impact assessment. The relevant changes might be made under other roadmap actions such as 16, which involves making licence amendments.

23), and therefore would need to happen before action 24. This action should also happen alongside the working group to consider options for managing blend (action 22) so that networks can ensure that approaches to pre-connection evaluation and post-connection blend management are consistent.

22. Working group to consider options for managing blend[73]

In the recommended solution package for system operation, dispatch and connections (see section 3.3.1), hydrogen blend would be managed in the first instance by constraints on producers, in particular setting out that the gas they inject must not cause the immediate locality of the grid to exceed the blending cap. There may also be constraints on the impact that producers can have on other aspects of the local gas quality, such as Wobbe Index, to ensure that certain users' gas requirements are met. Network operators would play a backstop role, intervening to curtail producers only if and when they do not meet these requirements.

However, further technical work is needed by the networks to determine exactly what requirements need to be placed on producers, and whether any further tools or changes are needed to ensure that gas blend is managed appropriately. A forum of networks and other relevant stakeholders should be created to progress this area of work.

The timing of this action is driven by the need for findings to feed into action 23, where the preferred approach will be assessed further and put to formal consultation. We expect this process could take about 18 months, as it may require inputs from new technical studies.

23. Assessment of preferred approach to managing blend[74]

Once a preferred approach to pre-connection evaluation and post-connection management of gas blend has been agreed, and a better understanding established of the locations and types of hydrogen producers applying for connections, detailed proposals should be considered by Ofgem and then put to the industry for wider consultation. The timing of this action is therefore driven by the need to wait for outputs from actions 18, 21 and 22.

The assessment and consultation should also consider how the preferred approach interacts with the support framework implemented by BEIS, so that the industry can ensure that any distortions created by the interaction of the commercial framework and support framework are limited. For example, if support is entirely output-based (i.e. paid per MWh of hydrogen produced), hydrogen investors may be highly sensitive to the risk of curtailment, and only willing to connect where the risk of hydrogen blend reaching the cap is minimal. If this is perceived to be likely to become an issue, more complex arrangements (e.g. implementing some form of compensation for curtailment) may need to be considered.

[73] This action is required in order to implement the recommended solution package for system operation, dispatch and connections described in section 3.3.1.

[74] This action is required in order to implement the recommended solution package for system operation, dispatch and connections described in section 3.3.1.

We expect this process could take about a year.

24. Develop connection agreement for hydrogen connections[75]

Once an approach to managing blend has been established through the assessment and consultation in action 23, standardised hydrogen connection agreements can be developed. These can build on the bespoke connection agreements used during the preparation stage.

Ideally the networks would coordinate to ensure consistency in their approaches (or even develop a single distribution connection agreement template that would apply across all GDNs). There would also be benefits to including a review of biomethane connection agreements as part of this work, to achieve consistency where possible.

We expect this process could take about a year.

25. Modify UNC to reflect required changes in entry requirements and system operation[76]

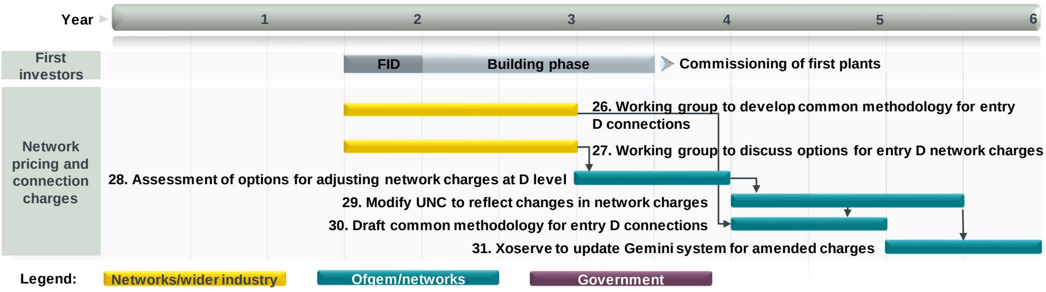
At this stage, some modifications are likely to be needed to the UNC to create a more permanent framework for hydrogen blending. Some of these changes may need to reflect decisions made as part of action 23 above.

If an initial review finds that there are extensive changes required, Ofgem may consider using the Significant Code Review mechanism and possibly coordinating these changes with any required changes to licences identified as part of action 17.

We expect this process could take about 18 months.

4.3.3 Actions related to network charges

Figure 20 Standardisation stage: actions related to network charges



Source: Frontier Economics

75 This action is required in order to implement the recommended solution package for a level playing field between entry connections described in section 3.3.4.

76 This action is required in order to implement the recommended solution package for system operation, dispatch and connections described in section 3.3.1.

26. Working group to develop common methodology for distribution entry connections[77]

In the recommended solution packages, we propose that a common methodology for distribution entry connections across GDNs is established. This should apply to hydrogen connections as well as other distribution connections (e.g. biomethane).

Developing a common methodology for distribution entry connections will require a coordinated approach across networks, and therefore at the first instance we suggest that a forum is established that is tasked with the responsibility of developing these common rules. This should build on the thinking already undertaken for biomethane connections. This group could also discuss ongoing changes to the common methodology going forward.

We expect this process could take about 18 months.

27. Working group to discuss options for distribution network charges[78]

In Section 3, we recommend a change to the existing distribution network charges applied at entry (i.e. network prices and the charging boundary of entry connections) in order to ensure the cost-reflectivity of the charges. The same approach should ideally apply to both hydrogen and biomethane injections.

This process will require a coordinated approach across networks and so we suggest that a forum is established that is tasked with the responsibility of developing the options for amending the distribution network charges. This should build on the thinking that has already been undertaken for biomethane connections. Further work may also be required to determine particular aspects of the recommended solutions. For instance, it may be necessary to understand what the relevant network costs and benefits of connections at the distribution network (rather than the transmission network) are. This forum could also discuss ongoing changes to the charging framework going forward.

A level of coordination might be required between actions 27 and 26 such that the approach in relation to the charging boundary for entry connection discussed as part of action 27 is reflected in the common entry connection methodology rules (action 26). In reality, it is likely that the same working group will take forward actions relating to both the common entry connection methodology (action 26) and distribution charges (action 26).

We expect this process could take around 18 months.

28. Assessment of options for adjusting distribution network charges[79]

Once a preferred approach for adjusting distribution network charges has been agreed, and a better understanding established of the locations and types of hydrogen producers applying for connections, detailed proposals should be

77 This action is required in order to implement the recommended solution package for a level playing field between entry connections across GDNs described in section 3.3.4.

78 This action is required in order to implement the recommended solution package for distribution charges described in section 3.3.3.

79 This action is required in order to implement the recommended solution package for distribution charges described in section 3.3.3.

considered by Ofgem. These will then be put to the industry for wider consultation. Ofgem might want to establish a working group to draft and assess the proposed options for amending the network charges. The timing of this action is therefore driven by the need to wait for outputs from action 27.

The assessment and consultation should also consider how the preferred approach interacts with the support framework implemented by BEIS, so that the industry can ensure that any distortions created by the interactions of the commercial framework and support framework are minimised.

We expect this process could take about a year.

29. Modify UNC to reflect changes in distribution network charges[80]

Ofgem may consider that some modifications should be made to UNC to implement the proposed changes to distribution network charges. This might involve a further consultation by Ofgem on the proposed amendments to UNC.

We note that if an initial review finds that there are extensive changes required across different elements of the commercial framework, Ofgem may consider using the Significant Code Review mechanism to implement these changes.

We expect this process could take about 18 months.

30. Draft common methodology for distribution connections at entry[81]

Following agreement by the networks on the common methodology for entry connections under action 26, and Ofgem's decision for the connection boundary at entry under action 29, the networks could draft the common methodology for distribution connections at entry, which will be subject to Ofgem approval.

We expect this process could take about a year.

31. Xoserve to update Gemini system for amending the distribution charges[82]

Xoserve may need to update the Gemini system to calculate and invoice the amended distribution network charges. In addition, we understand that the Gemini system may need to change to reflect changes in hydrogen measurement (e.g. if a new meter type is required for hydrogen injections). Xoserve should start updating the system after Ofgem has published its 'minded-to decision' for the amended distribution network charges at action 29.

We expect this process could take about a year.

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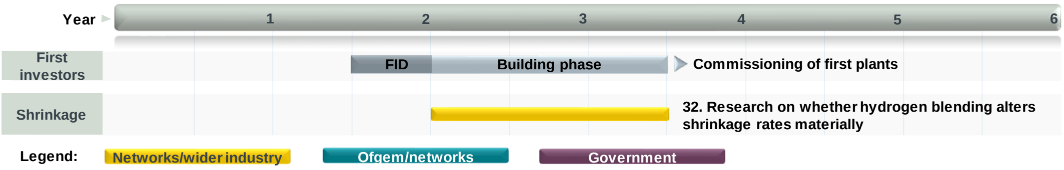
[80] This action is required in order to implement the recommended solution package for distribution charges described in section 3.3.3.

[81] This action is required in order to implement the recommended solution package for a level playing field between entry connections described in section 3.3.4.

[82] This action is required in order to implement the recommended solution package for distribution charges described in section 3.3.3.

4.3.4 Actions related to shrinkage

Figure 21 Standardisation stage: shrinkage



Source: Frontier Economics

32. Research on whether hydrogen blending materially alters shrinkage rates[83]

Further testing will be needed to verify whether hydrogen blending materially alters shrinkage rates.

We recommend that this action is initiated early in the standardisation stage. This will ensure that there is sufficient time to make any further amendments to the commercial framework if the study indicates that hydrogen significantly alters shrinkage rates.

We expect this process could take about a year.

[83] This action will be required to understand whether the current treatment and measurement of shrinkage gas is appropriate in a hydrogen blended system as explained in Annex D and confirmed through the stakeholder engagement process.

5 CONCLUSIONS AND IMMEDIATE NEXT STEPS

The CCC has highlighted that low-carbon hydrogen should have a significant role to play in meeting the UK's net zero target. In their 'Further Ambition' scenario, they predict that, by 2050, up to 270TWh of low-carbon hydrogen would be required in a year.[84] However, at present, there is no large-scale production of low-carbon hydrogen in the UK. For hydrogen to be the viable option envisaged by the CCC, early deployment projects must get off the ground in the 2020s.

Recent policy announcements indicate that the government is committed to explore the option of hydrogen in the transition to net zero.

- As part of its consultation on options for business models for carbon capture, usage and storage (CCUS), BEIS stated that it is: *'committed to exploring the option of hydrogen as a flexible and strategic decarbonised energy carrier for the UK, alongside electricity and other decarbonised gases.'*[85]
- As part of its consultation on the green gas support scheme, BEIS invited views on: '*what mechanisms might be appropriate for longer term green gas support, and on the potential for including alternative sources of green gas such as hydrogen blending in the future.*'[86]
- The Offshore Wind Sector Deal, which sets out commitments for the industry and government aimed at delivering benefits for the deployment of offshore wind, states: '*As the electricity system evolves, hybrid projects linking offshore wind with large scale storage or hydrogen or interconnection may develop into efficient and cost-effective solutions to help the UK decarbonise. The government will work with the sector and interested stakeholders to consider the best way to incentivise new technologies consistent with the principles of competition, maximising economic value for the UK and ensuring value for consumers.*'[87]

If blending can be achieved successfully, it could be an important transitional milestone to help to deliver these stated government intentions. Blending can support the initial development of larger-scale hydrogen production by offering a potentially stable demand for hydrogen that could form an important part of the case to invest in hydrogen. This could also potentially unlock future scenarios in which some systems convert to 100% hydrogen.

While there are still important questions to be answered in relation to the technical and safety case of hydrogen blending, those are being taken forward by the

[84] CCC (2019), *Net Zero Technical report*, https://www.theccc.org.uk/wp-content/uploads/2019/05/Net-Zero-Technical-report-CCC.pdf, p.21.

[85] BEIS (2019), *Business models for CCUS; Consultation*, https://www.gov.uk/government/consultations/carbon-capture-usage-and-storage-ccus-business-models.

[86] BEIS (2020), *Future support for low carbon heat; Consultation*, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/888736/future-support-for-low-carbon-heat-consultation.pdf.

[87] HM Government (2019), *Offshore Wind Sector Deal: Industrial Strategy*, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/790950/BEIS_Offshore_Wind_Single_Pages_web_optimised.pdf.

industry, such as through the HyDeploy project. Should these be successful, it is important that the commercial arrangements can facilitate a blended gas system.

We have made what we consider to be reasonable assumptions about the early development of a blended hydrogen system.[88] Based on those assumptions we expect existing mechanisms, such as industry-driven code and licence modification processes, will be key to implement the changes in the framework for hydrogen blending. In addition, the industry has already initiated some actions that will be critical for enabling hydrogen blending (or enabling other low-carbon gases to connect to the network).[89]

What is needed now is a clear signal that hydrogen blending – if proven to be technically feasible – is seen by government to be an important transitional option, alongside a view about when it hopes early low-carbon hydrogen projects will be connected. This will provide Ofgem and the industry with the green light to prioritise work to make sure that the commercial framework does not act as a barrier to this policy aim.

It will allow early action to be taken on tasks which have a longer lead time, such as the ones that involve changes to both the commercial framework and IT systems (for example, the future billing methodology). In addition, it will allow more time for considering options and building in learnings from other areas of work, such as from biomethane. An example of such an action is the definition of the entry point ownership boundary and respective responsibilities between networks and producers, where it will be important to consider the learnings from biomethane connections on which risks are best managed by networks and which are best managed by producers.

This signal will also mean that development of the commercial framework for low-carbon hydrogen can be properly joined up with the work on biomethane, where industry discussions are ongoing. There are a number of areas where there would be a clear benefit to developing a consistent commercial framework across low-carbon gases (for example in relation to the arrangements for connection and network charging at the distribution level). However, achieving this will require the engagement of a greater number of stakeholders. A clear view on the likely timing of the first need for hydrogen blending will allow the relevant stakeholder discussions to be joined up and the work coordinated, while ensuring it can be delivered in time for the early hydrogen projects.

Once the government has given a high-level policy direction, it can also work with Ofgem to ensure that this priority is reflected in Ofgem's regulatory framework and forward workplan. For example, as part of the RIIO-2 price control framework, Ofgem is introducing a Strategic Innovation Fund for projects focusing on achieving net zero targets. Ofgem has said that it will collaborate with organisations including BEIS, UKRI and the HSE to set innovation challenges. Through this channel, the

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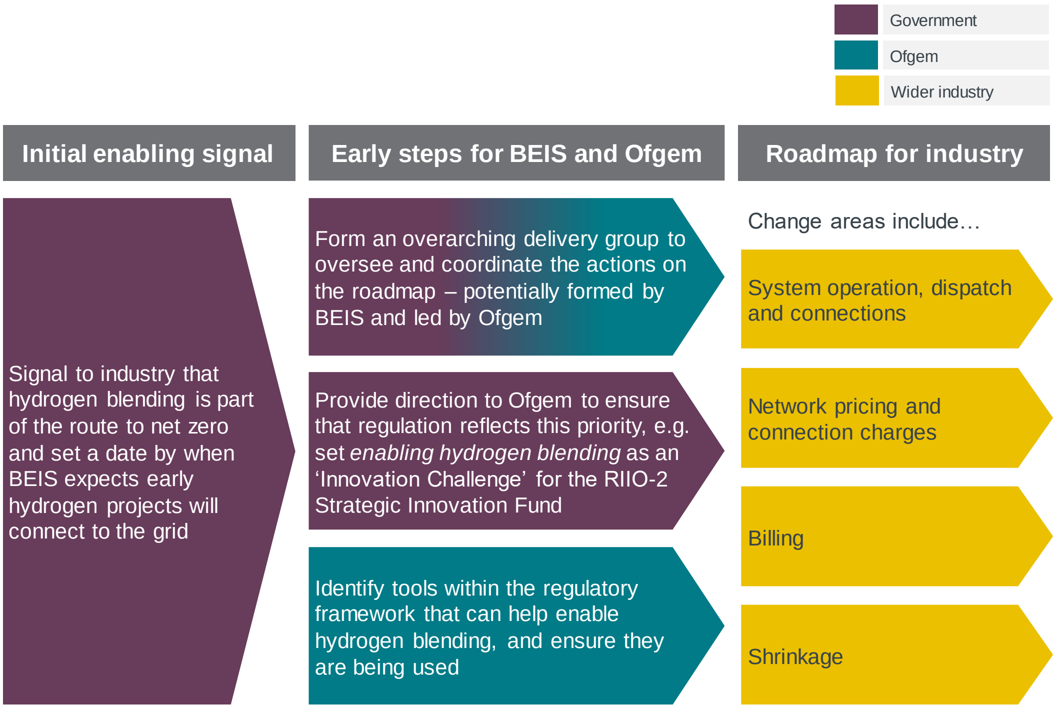
88 Action 15 of our roadmap includes a review of our assumptions about the early development of a blended hydrogen system and a re-assessment of the roadmap if our assumptions do not hold.

89 For example, the ongoing work on the future billing methodology. See https://futurebillingmethodology.co.uk/.

government should provide clear direction that enabling hydrogen blending should be a key focus for the Strategic Innovation Fund.[90]

The diagram below illustrates immediate next steps that BEIS and Ofgem can take in order to enable the industry to start work on the commercial framework.

Figure 22 Next steps for BEIS and Ofgem



Source: Frontier Economics

However, there are some next steps from the roadmap that the industry can initiate immediately. We set these out below.

5.1.1 Low-regret actions for the industry

Some of the actions set out in the roadmap are low-regret, meaning that they involve low resource costs and allow for options to remain open in relation to hydrogen blending. There are benefits from starting these actions at an early stage: better 'in principle' solutions can often be reached if thinking has begun before specific projects are on the table.

In addition, a number of the actions for enabling hydrogen blending will require some degree of coordination with the ongoing discussions for developing the biomethane framework. Initiating these actions will help ensure a consistent framework for biomethane and hydrogen connections.

The following actions are low-regret. Most will require a degree of coordination with biomethane and can build on the ongoing thinking for biomethane connections. We therefore recommend that these actions are initiated immediately.

[90] Ofgem (2020), *RIIO-2 Draft Determinations – Core Document*, https://www.ofgem.gov.uk/system/files/docs/2020/07/draft_determinations_-_core_document_redacted.pdf.

- Action 7: discuss entry point ownership boundary and responsibilities between networks and producers;
- Action 11: forum to develop future billing methodology options;
- Action 15: sensitivity testing of baseline assumptions;
- Action 22: forum to consider options for managing hydrogen blend;
- Action 26: forum to develop common methodology for distribution entry connections; and
- Action 27: forum to discuss options for distribution network charges.

There may be other actions that the government and Ofgem consider should be completed immediately, for example to inform decisions they are currently making around the future role of hydrogen blending. If so, these should be communicated to stakeholders so they can prioritise their completion.

ANNEX A OVERVIEW OF OUR METHODOLOGY

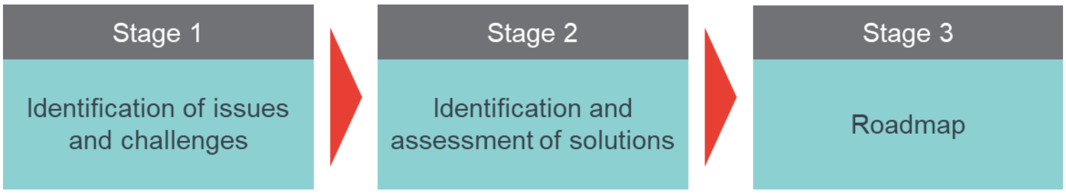
In this section we provide an overview of our methodology.

A.1 Our approach

Our work was structured around three stages, as illustrated in Figure 23 below.

1. **Identification of issues and challenges:** We identified the elements of the current commercial framework that would need to change or to be introduced to enable hydrogen blending.
2. **Identification and assessment of solutions:** We developed solution packages to address the issues and challenges identified in the previous stage; and assessed these packages to provide recommended solutions.
3. **Roadmap:** We developed a roadmap for the industry, setting out areas of work that need to be taken forward to implement the recommended solution packages.

Figure 23 Overview of approach



Source: Frontier Economics

We describe the work undertaken at each stage in more detail below.

A.1.1 Stage 1: Identification of issues and challenges

Figure 24 Stage 1 steps

Source: Frontier Economics

The aim of stage 1 was to identify which areas of the commercial framework may need to change to enable hydrogen blending. To do this, we undertook the following steps.

- **Identify scenarios and drivers for change:** Given the uncertainty around how hydrogen production will develop and what a blended system could look like, we identified a range of potential future outcomes for hydrogen blending. Across this range of possible outcomes, we identified which features of hydrogen blending would drive change to the commercial framework. For example, this includes features related to the new physical properties of hydrogen, the higher number of grid injections, and the requirement to control the hydrogen blend below the cap.

- **Identify issues and challenges:** Drawing on step 1, we identified a long list of potential issues for the commercial framework. As described in section 2.2, we distinguished between issues that would need to be solved under the baseline circumstances, and issues which may only arise under some future circumstances. We also identified some issues that are of a technical or legal nature.
- **Criteria for successful solutions:** We also set out at this stage a list of criteria that would be used to assess potential solutions to the issues identified. These criteria are described in section 2.1.
- **Stakeholder engagement:** We engaged extensively with relevant stakeholders to develop, test and challenge our findings for stage 1 (see section A.2 below).

A.1.2 Stage 2: Identification and assessment of solutions

Figure 25 Stage 2 steps

Source: Frontier Economics

The aim of Stage 2 was to identify and assess possible solutions for the issues identified in stage 1 and to provide recommendations. To do this, we undertook the following steps.

- **Develop long list of solutions:** For each area of change identified in stage 1, we developed a long list of potential solutions (i.e. potential modifications to the existing commercial arrangements across the six components of the commercial framework). We combined these solutions into internally consistent solution ‘packages’, each of which could be assessed/evaluated individually. We distinguished between solution packages required in baseline circumstances and solution packages required in some future circumstances.
- **Evaluation of solutions:** We assessed our long list of solution packages under the baseline circumstances against the evaluation criteria set out in stage 1. Our evaluation also took into account the potential changes that could be required in the longer term, to ensure that our recommendations are robust to potential future change. Based on the detailed evaluation, we summarised the key trade-offs between alternative solutions and set out the circumstances under which one solution might be preferred over another.
- **Recommendation:** On the basis of our evaluation in the step above, we identify a preferred solution under the baseline circumstances.
- **Stakeholder engagement:** We engaged extensively with relevant stakeholders to develop, test and challenge our findings for stage 2 (see section A.2 below).

A.1.3 Stage 3: Roadmap

Figure 26 Stage 3 steps

Source: Frontier Economics

The aim of stage 3 was to develop a roadmap of the commercial and regulatory actions that would need to take place to implement the recommended solution packages.

In this final stage, we undertook the following steps.

- **Develop road map for preferred solutions:** We identified the list of commercial and regulatory actions that would be required to implement the recommended solutions set out in stage 2. As described in section 4, we distinguish between two phases of work – a preparation stage (i.e. actions required to enable a small number of hydrogen producers to connect) and a standardisation stage (i.e. actions for developed a standardised and more comprehensive framework for hydrogen blending).
- **Test with stakeholders:** We engaged extensively with relevant stakeholders to develop, test and challenge our findings for stage 3 (see section A.2 below).

A.2 Stakeholder Engagement

Developing the commercial framework to enable hydrogen blending will require coordinated efforts across a range of stakeholders, and so stakeholder engagement has been a crucial input to our work throughout this study.

At the start of this work, we identified a range of key stakeholders to engage. These are set out in Figure 27.

Figure 27 Stakeholders engaged in this work

Gas Networks	Wider industry stakeholders	Government and regulatory bodies
Cadent	Energy UK	BEIS
National Grid Gas	Xoserve	Ofgem
Northern Gas Networks	Renewable Energy Association / Trinity Organics*	
SGN	Oxford Energy Consultants	
Wales & West Utilities		

Source: Frontier Economics

Note (*): Due to Covid-19 related reasons, Renewable Energy Association (REA) did not attend the workshops for Stages 2 and 3. REA extended the invite to one of its members (Trinity Organics) that provided input and participated in all the workshops.

To ensure that we engaged with these stakeholders in the most constructive way, we carried out two types of engagement:

- **Functional engagement:** We engaged with the gas networks and wider industry experts through a series of functional group workshops, where stakeholders could provide inputs to the study and act as a sounding board for proposed actions. We held workshops at the end of each stage of the project where we sought challenges on our emerging thinking and also collected information on specific technical questions.
- **BEIS and Ofgem engagement:** We engaged with BEIS and Ofgem at key checkpoints, to communicate emerging thinking as the project developed and to gather and incorporate their feedback.

We are very grateful for the inputs that we have received from these stakeholders, and we have reflected their feedback in our proposed recommendations (see section 3.3) and the roadmap to enable hydrogen blending (see section 4).

ANNEX B RELEVANT OBJECTIVES OF THE UNC FOR ASSESSING NETWORK CHARGES

To determine whether the status quo network charges are appropriate in a future hydrogen blended world and options for amending these, we assess the status quo network charges against some principles based on the relevant objectives of the UNC. We focus on two principles that encompass the UNC objectives[91]:

- Cost reflectivity; and
- Effective competition

We note that UNC also refers to another objective: taking into account the developments in the transportation business. Although we do not explicitly consider this objective, we built this in our assessment by taking into account the context of hydrogen blending when assessing the network charges against the objectives of cost reflectivity and effective competition.

B.1 Cost reflectivity

Network charges should reflect the forward looking marginal costs that users impose on the network through a change in their use. This is important to achieving an economically efficient outcome: if charges are cost reflective, users will internalise the network costs which they cause when making a decision about how to use the network. This will in turn ensure that overall value chain costs are optimised, and that customer interests are protected.

If there is an excess capacity in some locations as a result of a reduction in network use over time, then the marginal cost of using capacity may be close to or equal to zero. If there is spare capacity everywhere and no demand growth is expected, the marginal cost of capacity everywhere may be zero. At this point, marginal cost based signals for capacity look very similar to postage stamp charges, i.e. uniform capacity charges throughout the network.

Efficient cost reflective charges may not recover all costs which have been incurred. Therefore, additional charges are required to recover costs (i.e. cost recovery charges). Such charges should have as an objective creating minimal changes in behaviour relative to a set of efficient charges. This implies that cost recovery charges should be structured in such a way as to target price-insensitive uses of the network, taking into account equity issues.[92]

B.2 Effective competition

In some senses, the effectiveness of competition in delivering efficient outcomes depends on the cost reflectivity of the network charges. If competition takes place

[91] UNC, Standard Special Condition A5: Obligations as Regard Charging Methodology, para 5.

[92] For example, it may be seen as inequitable to target a disproportionately large share of cost recovery on a user or group of users simply because they are less likely to change behaviour.

against the background of non-cost reflective charges, it may not result in efficient outcomes.

Beyond the impact of cost reflectivity on effective competition, another potential area to consider relates to the effectiveness of the competitive process itself. Relevant issues to consider in relation to that include an assessment of:

- the transparency and complexity of the charges, or the methodologies used to calculate them;
- whether charges that are not designed to send cost signals (e.g. cost recovery charges) are applied in a non-discriminatory manner;
- the ease with which shippers can enter and exit the market, and hence the potential number of different physical gas sources competing to serve demand, liquidity of the NBP and the degree of competition on downstream markets; and
- the risk profile of shippers.

We note that these considerations in assessing effective competition are broadly in line with the principles that Ofgem considered in its Targeted Charging Review in the electricity sector.[93] The focus of the Targeted Charging Review principally related to issues concerning the distortion of competition that arise from the application of cost recovery charges across network users. Ofgem assessed the cost recovery charges against three principles:

- reducing harmful distortions;
- fairness; and
- proportionality and practical considerations.

[93] Ofgem (2018), Targeted Charging Review: minded to decision and draft impact assessment, https://www.ofgem.gov.uk/system/files/docs/2018/11/targeted_charging_review_minded_to_decision_and_draft_impact_assessment.pdf.

ANNEX C DEVELOPMENT OF COMMERCIAL AND POLICY FRAMEWORK FOR BIOMETHANE PRODUCERS

In this section we provide an overview of the development of the commercial and policy framework for biomethane producers over time.

C.1 Timeline of policy framework developments

The key actions for developing the policy support for biomethane producers are shown in Figure 26 below.

Figure 28 Timeline of key actions for developing the biomethane policy support

Source: Frontier Economics (sources referenced in the remainder of this section)

- The Energy Act **2008** made provisions for a Renewable Heat Incentive (RHI) to encourage the renewable generation of heat by biomethane producers, amongst others. The Energy Act defined biomethane as 'biogas which is suitable for conveyance through pipes to premises in accordance with a licence under section 7 of the Gas Act 1986 (c. 44) (gas transporter licences)'.[94]
- **In 2011**, Ofgem was appointed by DECC to launch and administer the non-domestic Renewable Heat Incentive (RHI) Regulations 2011.[95]
- **In 2012**, Ofgem held a consultation on amendments to Ofgem's interpretation of the RHI Regulations 2011. Ofgem originally interpreted the RHI Regulation 2011 to exclude biogas production plants from the RHI financing eligibility.[96] However, following a European Commission State aid approval for the 2011 RHI scheme, Ofgem considered that biogas production plants should be considered as part of the installation eligible for financing, as they are part of the equipment required to convert biogas to biomethane.[97]

94 Energy Act 2008, Section 100. Available at http://www.legislation.gov.uk/ukpga/2008/32/section/100.

95 The Renewable Heat Incentive Scheme Regulations 2011. Available at http://www.legislation.gov.uk/uksi/2011/2860/pdfs/uksi_20112860_en.pdf

96 Ofgem (2012), Consultation on amendments to Ofgem's administration of the Renewable Heat Incentive scheme, https://www.ofgem.gov.uk/sites/default/files/docs/2012/06/consultation-on-amendments-to-ofgems-administration-of-the-renewable-heat-incentive-scheme_0.pdf.

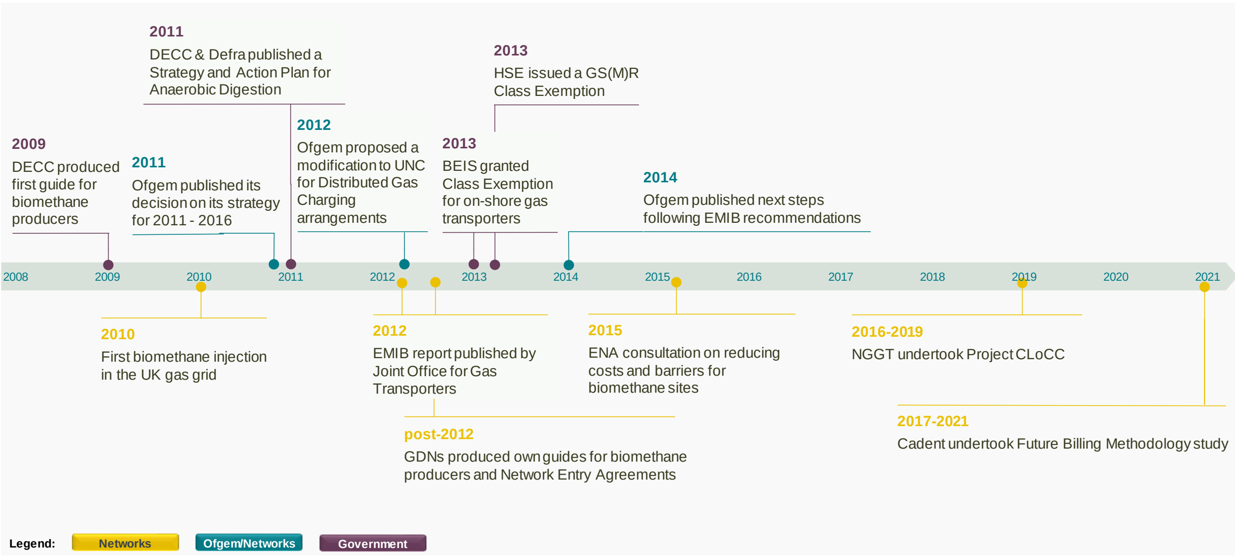
97 Ofgem (2012), Summary of responses to Ofgem's consultation on amendments to Ofgem's administration of the Renewable Heat Incentive scheme,

- Subsequently, there were a number of changes to the RHI. For example:
  - **In 2015**, Ofgem implemented a new, tiered tariff for new installations, as well as a number of eligibility criteria amendments.[98]
  - **In 2015**, Ofgem enforced new eligibility criteria, according to an updated sustainability criteria produced by DECC.[99]
  - **In 2018**, the non-domestic RHI regulations underwent a number of changes to the RHI application process for biomethane plants and the eligibility for equipment financing.[100]

C.2 Timeline of commercial framework developments

The key actions for developing the commercial framework to enable biomethane producers to connect to the gas grid are shown in Figure 29 below.

Figure 29 Timeline of key developments in the biomethane commercial frameworks



Source: Frontier Economics summary of sources referenced in the remainder of this section

These actions are as follows.

- **In 2009**, DECC produced a first guide for biomethane producers, outlining the initial regulatory and commercial conditions and future considerations for producing biomethane for the gas grid.[101]

https://www.ofgem.gov.uk/sites/default/files/docs/2012/09/decision-on-the-consultation-on-amendments-to-ofgem%27s-administration-of-the-renewable-heat-incentive-scheme_0.pdf

98 Ofgem (2015), Changes to the Non-Domestic RHI regulations (February 2015) – revised biomethane tariff and minor amendments, https://www.ofgem.gov.uk/publications-and-updates/changes-non-domestic-rhi-regulations-february-2015-revised-biomethane-tariff-and-minor-amendments.

99 Ofgem (2015), October 2015 changes to the Non-Domestic RHI regulations - Sustainability and the Biomass Suppliers' List, https://www.ofgem.gov.uk/publications-and-updates/october-2015-changes-non-domestic-rhi-regulations-sustainability-and-biomass-suppliers-list.

100 Ofgem (2018), Changes to the Non-domestic RHI regulations (June 2018), https://www.ofgem.gov.uk/publications-and-updates/changes-non-domestic-rhi-regulations-june-2018

101 DECC (2009), Biomethane into the Gas Network: A Guide for Producers, http://www.organics-recycling.org.uk/uploads/category1060/Biomethane%20into%20the%20Gas%20Grid%20a%20Guide%20for%20producers.pdf.

- **In 2010**, biomethane was first injected in the UK gas grid from the Didcot sewage works to the local grid to supply 200 homes with gas.[102]
- **In 2011**, Ofgem published its decision on its strategy for 2011 - 2016.[103] Ofgem stated that over the period 2011 – 2012, it would *'review the regulatory arrangements surrounding the connection of distributed generation and the injection of biomethane.'*[104] This decision followed a consultation by Ofgem in December 2010 on the strategy for RIIO-GD1.[105] The consultation covered a number of points on biomethane, with key areas of discussion being around removal of regulatory barriers for biomethane producers to connect to the distribution networks.
  - Ofgem outlined its plan to require GDNs to report on the capacity of biomethane connected to their networks. However, it proposed not to introduce any financial incentives around this, since the capacity of biomethane connected to the network was viewed to be largely driven by government incentives for producers, such as the RHI and feed-in-tariffs (FIT).
  - Ofgem's consultation asked respondents to provide their views on their plans to ensure regulatory barriers to biomethane producers connecting to the grid are removed, for example whether Ofgem should extend the existing standards of connection to biomethane producers and whether the costs of connecting biomethane plants should be socialised through general network charges.
- **In 2011,** DECC and Defra published a joint Strategy and Action Plan for Anaerobic Digestion.[106] This document outlined a number of actions for the years ahead, including a number of steps related to addressing the costs and complexity of connections to the grid for biomethane injections, as well as financial incentives for producers.[107]
- **In 2012**, the Joint Office for Gas Transporters produced a report on the Energy Market Issues for Biomethane (EMIB) on behalf of a number of the gas distribution companies.[108] The review investigated the potential barriers to the development of biomethane projects and their connection into the gas network. The report produced a set of recommendations in relation the GDNs'

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[102] The project was a joint venture between Thames Water, British Gas and Scotia Gas Networks. https://web.archive.org/web/20101209082747/http://www.thameswater.co.uk/cps/rde/xchg/corp/hs.xsl/1098 2.htm

[103] Ofgem (2011), Corporate Strategy and Plan 2011 - 2016, https://www.ofgem.gov.uk/ofgem-publications/37154/corporate-strategy-and-plan-2011-2016pdf.

[104] Ofgem (2011), Corporate Strategy and Plan 2011 - 2016, https://www.ofgem.gov.uk/ofgem-publications/37154/corporate-strategy-and-plan-2011-2016pdf, page 7.

[105] Ofgem (2010), Consultation on strategy for the next gas distribution price control - RIIO-GD1 Overview paper, https://www.ofgem.gov.uk/ofgem-publications/48268/riiogd1-overviewpdf

[106] DECC and Defra (2011), Anaerobic Digestion Strategy and Action Plan, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/69400/anaerobic-digestion-strat-action-plan.pdf

[107] DECC and Defra (2011), Anaerobic Digestion Strategy and Action Plan, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/69400/anaerobic-digestion-strat-action-plan.pdf, page 34, Table 2.

[108] National Grid, Northern Gas Networks, Scotia Gas Networks and Wales & West Utilities. See Joint Office for Gas Transporters (2012), Energy Market Issues for Biomethane Projects (EMIB), https://gasgov-mst-files.s3.eu-west-1.amazonaws.com/s3fs-public/ggf/EMIB%20Report%20V1.0.pdf.

connection policies, network capacity availability, technical standards for CV, gas quality regulation and data requirements.[109]

- As a result of this report:
  - GDNs developed the Network Entry Agreements reflecting the agreed connection policies in the EMIB Review Group Report; [110]
  - **In 2013**, BEIS granted a Class Exemption from the Gas Transporter Licence in respect of the delivery facilities connected to gas distribution networks;[111] and
  - **In 2013**, the HSE issued a Class Exemption to GS(M)R for biomethane producers.[112]
- **In 2012**, Ofgem approved a modification to the UNC for distributed gas charging arrangements.[113]
- **In 2014**, Ofgem published a letter on Ofgem's next steps for addressing the issues identified as part of the EMIB Review Group.[114] In this letter, Ofgem expressed its intention to take action on two areas of recommendations, namely the technical standards for CV; and the data requirements and transmission of CV data.[115]
- **In 2015**, the Energy Networks Association (ENA) produced a consultation on behalf of the Biomethane Campaign Working Group, on reducing costs and removing barriers for low-flow gas entry sites.[116] The consultation document put forward possible solutions to lighten the CV measurement requirements on biomethane sites, including moving governance of such sites from Ofgem to GDNs. However, Ofgem ultimately found little evidence that the alternative options would result in a better outcome for consumers and producers.[117]
- **In 2017**, National Grid Gas (now Cadent) initiated the Future Billing Methodology study, funded by the Network Innovation Competition (NIC).[118] The results of the study are expected to be published in 2021.

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109 Joint Office for Gas Transporters (2012), Energy Market Issues for Biomethane Projects (EMIB), https://gasgov-mst-files.s3.eu-west-1.amazonaws.com/s3fs-public/ggf/EMIB%20Report%20V1.0.pdf

110 Ofgem (2014), Open letter setting out our next steps for addressing Energy Market Issues for Biomethane (EMIB), https://www.ofgem.gov.uk/ofgem-publications/86979/emibopenletterfinal.pdf, Annex 1.

111 DECC (2013), Gas Transporter Licence Exemptions for onshore production of gas, https://www.gov.uk/government/consultations/gas-transporter-licence-exemption-for-onshore-production-of-gas.

112 Northern Gas Networks, Biomethane: A producer's handbook, https://biomethane.northerngasnetworks.co.uk/wp-content/uploads/2015/11/NGN-Biomethane-Full-document-low-res.pdf, page 67.

113 Ofgem (2012), Uniform Network Code (UNC) Modification 391 (UNC391): Distributed Gas Charging arrangements https://www.ofgem.gov.uk/ofgem-publications/62787/unc391d-pdf

114 Ofgem (2014), Open letter setting out our next steps for addressing Energy Market Issues for Biomethane (EMIB), https://www.ofgem.gov.uk/ofgem-publications/86979/emibopenletterfinal.pdf

115 Regarding data requirements and transmission, Ofgem committed to working further with stakeholders to produce a more detailed proposal for potential reduced data requirements on biomethane sites in a way that does not harm consumers.

116 ENA (2015), Reducing costs and removing barriers for low-flow gas entry sites: Transforming the Calorific Value (CV) regime for small sites, https://www.energynetworks.org/assets/files/news/consultation-responses/Reducing%20Costs%20and%20Removing%20Barriers%20Consultation%20PDF.pdf

117 Ofgem (2016), Ofgem response to ENA Consultation - Reducing Costs and Removing Barriers for Low Flow Entry Sites, https://www.ofgem.gov.uk/system/files/docs/2016/03/finalenabiomethaneconsultationresponseletter01032016.pdf

118 Future Billing Methodology, https://futurebillingmethodology.co.uk/

- **During 2016 - 2019**, National Grid Gas Transmission (NGGT) undertook Project CLoCC, funded through the NIC.[119] The project aimed to reduce the time and cost of connecting at the transmission level by challenging aspects of the connection process.

C.3 Key amendments to the commercial framework for incorporating biomethane producers

Dispatch and connections

Gas quality requirements

The gas quality requirements that biomethane producers have to meet are defined in the NEA between the producer and the gas transporter.[120] These requirements reflect the GS(M)R, but might also include additional requirements the Gas Transporter imposes on the producer, such as requirements on inserts like oxygen and carbon dioxide, amongst other parameters.[121] If biomethane producers cannot meet the (GS(M)R) requirements, then the GDN enters into a discussion with the Health & Safety Executive for an exemption.[122]

The EMIB report made a number of recommendations regarding the gas quality requirements for biomethane producers, as follows.[123]

- The water parameter according to the GS(M)R can be relaxed in the NEAs.
- A risk assessment should be carried out on the various gas quality parameters and what their limits should be, the frequency of measuring and the speed of response in case of a breach.
- The report specifically pointed out the possibility of relaxing the oxygen maximum of 0.2%, but that ENA should ask for the HSE's approval, subject to a study. An approval was subsequently granted, up to a maximum of 1% oxygen content.[124]

Ownership and responsibility of entry equipment

Throughout the various working groups and consultations the entry point ownership boundary and responsibilities between the biomethane producer and

[119] NGGT (2019), Project CLoCC: Close down report, https://www.nationalgrid.com/uk/gas-transmission/document/127116/download.

[120] The responsibilities of a Gas Transporter to provide such an agreement are listed under 'Standard Special Condition D12' of the Gas Transporter Licence (2017). https://epr.ofgem.gov.uk/Content/Documents/Standard%20Special%20Conditions%20-%20PART%20D%20Consolidated%20-%20Current%20Version.pdf

[121] DECC (2009), Biomethane into the Gas Network: A guide for producers, http://www.organics-recycling.org.uk/uploads/category1060/Biomethane%20into%20the%20Gas%20Grid%20a%20Guide%20for%20producers.pdf, paragraph 5.17.

[122] https://gasgov-mst-files.s3.eu-west-1.amazonaws.com/s3fs-public/ggf/HSE%20Statement.pdf

[123] National Grid, Northern Gas Networks, Scotia Gas Networks and Wales & West Utilities. See Joint Office for Gas Transporters (2012), Energy Market Issues for Biomethane Projects (EMIB), https://gasgov-mst-files.s3.eu-west-1.amazonaws.com/s3fs-public/ggf/EMIB%20Report%20V1.0.pdf.

[124] Northern Gas Networks, Biomethane: A producer's handbook, https://biomethane.northerngasnetworks.co.uk/wp-content/uploads/2015/11/NGN-Biomethane-Full-document-low-res.pdf, page 67.

the GDNs were discussed. Below, we first describe the entry equipment required to connect biomethane injections, before discussing the amendments to the rules around ownership of this equipment.

Entry equipment required

There are three key pieces of the biomethane network entry equipment that GDNs use to control biomethane injections (e.g. to stop gas entry when necessary).[125]

- **Remote Operating Valve (ROV):** an automatic valve or 'slam shut' is required to stop the injection of biomethane if it is not of appropriate quality, and also to prevent the over-pressurisation of the gas network. The GDN may have a remote operation capability to monitor and maintain safety of the network.
- **Remote Telemetry Unit (RTU):** the communication device between the biomethane network entry facility and the GDNs' Control Room. The data are used for billing and operational purposes.
- **Odorisation Unit:** introduces the 'gas smell' into the biomethane.

Other necessary equipment includes:[126]

- Gas Quality Monitoring Equipment to measure the energy content of the gas, and demonstrate to the GT and the HSE that the biomethane is compliant with the gas quality requirements;
- Biogas/Bio-SNG production and clean-up facilities;
- Enrichment equipment to ensure the biomethane meets the necessary CV conditions;
- Metering Equipment to measure the volume and energy levels of gas injected into the gas network; and
- Pressure control equipment as at some points on the LDZ, biomethane pressure will likely need either to be increased using compressor equipment, or reduced using a pressure reduction valve, to enable safe injection into the gas network.

Ownership of equipment

The EMIB report in 2012 recommended that each GDN develop a NEA that clearly sets out the entry point ownership boundary and responsibilities between the biomethane producer and the GDN.[127]

Prior to 2013, the connecting pipework necessary to inject gas into the network had to be owned and operated by a licensed gas transporter.[128] A key recommendation of the EMIB report was that Ofgem arranges a Class Exemption from the Gas Transporter License with respect to biomethane producers' delivery

[125] Northern Gas Networks, Biomethane: a producer's handbook, https://biomethane.northerngasnetworks.co.uk/wp-content/uploads/2015/11/NGN-Biomethane-Full-document-low-res.pdf, section 5.3.

[126] DECC (2009), Biomethane into the Gas Network: A guide for producers, http://www.organics-recycling.org.uk/uploads/category1060/Biomethane%20into%20the%20Gas%20Grid%20a%20Guide%20for%20producers.pdf, section v.

[127] National Grid, Northern Gas Networks, Scotia Gas Networks and Wales & West Utilities. See Joint Office for Gas Transporters (2012), Energy Market Issues for Biomethane Projects (EMIB), https://gasgov-mst-files.s3.eu-west-1.amazonaws.com/s3fs-public/ggf/EMIB%20Report%20V1.0.pdf.

[128] DECC (2009), Biomethane into the Gas Network: A guide for producers, http://www.organics-recycling.org.uk/uploads/category1060/Biomethane%20into%20the%20Gas%20Grid%20a%20Guide%20for%20producers.pdf, paragraph 5.6.

facilities connected at the distribution level.[129] The exemption was granted and introduced in 2013, meaning biomethane producers were able to own and operate the pipework connecting them to the network.[130] However, the NEAs allow the GDNs to remotely operate some of the connecting equipment.

The EMIB report also pointed out that the Gas (Calculation of Thermal Energy) Regulations assumed that GDNs own the CV measurement equipment and that BEIS should assess and potentially amend the Gas (Calculation of Thermal Energy) Regulations to reflect the fact that producers tend to own the measurement equipment.[131] BEIS subsequently allowed an interpretation of these regulations that producers can own the measuring equipment as long as the GDN can safely access and operate the equipment.[132]

Connections process

Biogas, once upgraded to biomethane, can in theory be injected either at the transmission level or at the distribution level. Regarding connection at the transmission level, some stakeholders have argued that in practice, applying for an entry connection for biomethane production can be a costly (up to £2m) and time consuming (up to 3 years) process.[133] To our knowledge, Murrow Entry Point is the only currently operational biomethane injection point connected at the transmission level.[134]

To make the NTS more accessible to these new gas sources, NGGT initiated Project CLoCC in 2016.[135] The project aimed to facilitate new sources of gas, such as biomethane and hydrogen, to connect to the NTS, by reducing the cost of connection to under £1m, and the required time to under a year. In order to facilitate the connection of biomethane customers in particular, any requests for oxygen specification in excess of the NTS requirement and within the GS(M)R limit will be considered on a case-by-case basis.[136]

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[129] National Grid, Northern Gas Networks, Scotia Gas Networks and Wales & West Utilities. See Joint Office for Gas Transporters (2012), Energy Market Issues for Biomethane Projects (EMIB), https://gasgov-mst-files.s3.eu-west-1.amazonaws.com/s3fs-public/ggf/EMIB%20Report%20V1.0.pdf.

[130] DECC (2013), Gas Transporter Licence Exemptions for onshore production of gas, https://www.gov.uk/government/consultations/gas-transporter-licence-exemption-for-onshore-production-of-gas.

[131] National Grid, Northern Gas Networks, Scotia Gas Networks and Wales & West Utilities. See Joint Office for Gas Transporters (2012), Energy Market Issues for Biomethane Projects (EMIB), https://gasgov-mst-files.s3.eu-west-1.amazonaws.com/s3fs-public/ggf/EMIB%20Report%20V1.0.pdf.

[132] Ofgem (2014), Open letter setting out our next steps for addressing Energy Market Issues for Biomethane (EMIB), https://www.ofgem.gov.uk/ofgem-publications/86979/emibopenletterfinal.pdf, Annex 2.

[133] National Grid (2017), Gas Ten Year Statement 2017, https://www.nationalgrid.com/sites/default/files/documents/GTYS%202017_1.pdf , page 29.

[134] National Grid (2019), Notice of Gas Transmission Transportation Charges, https://www.nationalgrid.com/uk/gas-transmission/uk/gas-transmission/document/125616/download

[135] National Grid, Project CLoCC: close down report, https://www.nationalgrid.com/uk/gas-transmission/document/127116/download.

[136] National Grid (2017), Gas Ten Year Statement 2017, https://www.nationalgrid.com/sites/default/files/documents/GTYS%202017_1.pdf.

Network charges

In 2012, Ofgem proposed an amendment to the UNC to introduce a new charge (the LDZ SECC) for producers that connect directly at the distribution level.[137] Ofgem explained that it envisaged that a significant number of biomethane facilities may look to connect to the distribution systems in the near future and as such, the introduction of the LDZ SECC will more accurately reflect the costs associated with the entry of distributed gas directly into the distribution network.

Billing regime

As discussed in Section 4, the current billing regime is based on a Flow Weighted Average Calorific Value (FWACV) approach. The FWACV is calculated from the flows and the CVs of all the gas entering a given charging area. As a consumer protection measure, the FWACV is subject to a cap, i.e. the FWACV used for customer billing cannot exceed a value of 1.0 MJ/m^3 above the lowest measured daily CV average of the inputs into the charging area. This means that an insignificant volume of low CV gas (such as biomethane) can cap an entire charging area and lead to under-billing of customers. This was addressed for biomethane by adding propane to enrich the gas to meet the target CV.

The Future Billing Methodology is a NIC project undertaken by Cadent that explores alternative options for the billing methodology to help integrate diverse gas sources (e.g. biomethane), without the need to process the injections.[138]

[137] Ofgem (2012), Uniform Network Code (UNC) Modification 391 (UNC391): Distributed Gas Charging arrangements https://www.ofgem.gov.uk/ofgem-publications/62787/unc391d-pdf

[138] Ofgem, Future Billing Methodology: Project Summary, https://www.ofgem.gov.uk/ofgem-publications/107840

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