MARKET AND REGULATORY FRAMEWORKS FOR A LOW CARBON GAS SYSTEM

A report for BEIS

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Sarah Deasley
+44 (20) 7031 7112
sarah.deasley@frontier-economics.com

Claire Thornhill
+44 (20) 7031 7099
claire.thornhill@frontier-economics.com

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EXECUTIVE SUMMARY

To meet the 2050 target under the Climate Change Act cost-effectively, it is likely that the heat sector will need to be close to completely decarbonised. This will have significant – and currently uncertain – consequences for the future role of the gas sector. Changes to factors such as the vector fuel, the scale of network usage, or end user heating systems will result in the emergence of different market models and requirements for regulatory frameworks to support the required levels of investment.

As part of its wider research into heat decarbonisation, BEIS has commissioned Frontier Economics to:

- first identify what market models and regulatory frameworks may look like in a 2050 steady state under a range of scenarios for a low carbon gas system, and to understand their strengths and weaknesses; and
- second, look at the risks, uncertainties and barriers there may be in the transition to a low carbon gas system, and to present options for how these may be managed or overcome.

The aim of this project is not to describe optimal scenarios for gas system decarbonisation or to set out recommendations for Government action. Rather this report aims to objectively describe challenges likely to be associated with a low carbon gas system, and present a wide range of strategies for overcoming these challenges. This summary therefore does not set out any high level conclusions or recommendations, and instead focusses on a description of the work carried out.

Methodology

We have applied an approach which combines bottom up analysis of the economic and technical characteristics of low carbon heat systems with top down creative thinking and discussions with stakeholders.

- **Bottom up** – Our bottom up approach involved systematic analysis of the economic and technical characteristics of a 2050 low carbon gas system, and the required changes en route to that system. For the 2050 steady state, we considered, for example, the scale and cost structure of the technologies and infrastructure involved and the likely degree of competition. We considered the consequence of these for how businesses might organise themselves to manage costs or risks. We also looked at where Government intervention might be useful to increase the efficiency or deliver public goods such as security of supply. Similarly, for the transition, we analysed the economic and technological characteristics of the transformation of the gas system required out to 2050, and assessed where actions would be required to ensure this transition was realised.
- **Top down** – Our top down approach involved workshops and bilateral discussions with our team of experts aimed at stimulating creative thinking and big picture analysis.

- **Stakeholder challenge** – The outputs of these processes were then presented for challenge at two stakeholder workshops, including representatives from across the gas value chain as well as from government and regulatory bodies.

This report represents the synthesis of these pieces of work.

Report structure

In Section 2 we describe three low carbon gas system scenarios for 2050.

- High Hydrogen involves the conversion of all gas supply to hydrogen, and includes the use of hydrogen to meet transport demand.
- Methane Peaking describes a system where low carbon methane (produced from waste and biomass) is used only in industry and for meeting peak heat demand via hybrid heat pumps.
- The Regional Gas Grids scenario involves the separation of the existing national grid into multiple separate pipeline grids – with about 70% of total gas demand met from hydrogen; the rest is met by low carbon methane.

These scenarios have been developed specifically to stimulate and test thinking on the appropriate market and regulatory models for a low carbon gas system in 2050. While they have been designed to be technically feasible and internally consistent, they do not reflect an attempt to forecast the most likely or most desirable 2050 outcomes.

In Sections 3-6 we present the market models and regulatory frameworks for a 2050 steady state.

The models developed in this project describe the market conditions and regulatory structures that could emerge in response to different scenarios for the decarbonisation of the gas system in 2050. Looking across the whole value chain, from upstream production to consumption, they set out how markets could operate to meet the needs of consumers, investors and industry participants. They also describe how government and other regulatory stakeholders could provide different levels of market intervention, regulation and centralised coordination.

We present two models for each scenario. First, we look at a ‘market-driven’ model where Government intervention is at a minimal level (with a focus mainly on managing the emissions externality and regulating natural monopolies). We then look at an ‘additional-intervention’ model for each scenario. These are iterations of the market-driven models, which explore the implications of greater government- or regulatory intervention where this might be beneficial to the functioning of the gas system.

All of the models have been designed to meet the needs of market participants in a rational and efficient way, to be stable, and to deliver on policy priorities such as security of supply. However, there are trade-offs between the extent to which the models deliver against each of these aims. For example, measures to improve security of supply (for example by increasing storage capacity) are likely to increase cost. Therefore, in Section 7, we present a qualitative appraisal of Government interventions in each model against a range of criteria.

Section 8 describes the challenges in the transition. We first describe the economic and technical characteristics of the investment pathways. We then focus on three areas where action is likely to be required to ensure the transition is delivered:

- uncertainty and keeping options open;
- coordination requirements and policy risk; and
- consumer experience and protection.

For each of these areas, we set out a number of options for managing the challenges, and describe the pros and cons of each.

Purpose of these outputs

This report does not include recommendations for Government action or conclusions on the best path forward. Instead, it is meant to be part of the detailed body of evidence that BEIS is considering on long term heat pathways. The emphasis has therefore been on presenting our objective analysis, rather than on pulling out insights on what this might mean for policy makers.

1 INTRODUCTION

Meeting the 2050 greenhouse gas emissions target is likely to have significant – and currently uncertain - consequences for the gas sector.

As part of its wider research into heat decarbonisation, BEIS has commissioned Frontier Economics to objectively describe challenges likely to be associated with a low carbon gas system, and to present a wide range of strategies for overcoming these challenges.

This report is structured as follows.

- Section 2 sets out three scenarios developed to stimulate and test thinking on the appropriate market and regulatory models for a low carbon gas system in 2050.
- To develop market and regulatory models for 2050, we have combined bottom up analysis of the economic and technical characteristics of low carbon heat systems with top down creative thinking and discussions with stakeholders. Section 3 describes this methodology.
- Sections 4-7 set out market and regulatory models for each of the three scenarios. A ‘market-driven’ model where Government intervention is at a minimal level and an ‘additional-intervention’ model are included for each scenario. We also present an appraisal of Government interventions in each model against a range of criteria.
- Section 8 describes the challenges in the transition. We describe the economic and technical characteristics of the investment pathways and outline options for overcoming the associated challenges in the transition.
- We conclude with a brief summary of our findings in Section 9.

2 OVERVIEW OF 2050 SCENARIOS

To consider a wide range of potential market and regulatory outcomes for gas networks that may be required in 2050, we developed three distinct scenarios for 2050 gas use with the objectives of ensuring that:

1. a diverse range of options for the supply and demand of gas (with a focus on those aspects most likely to influence the model) were covered across the scenarios;
2. each scenario is internally consistent in its design; and
3. each scenario is consistent with meeting the UK's 2050 emission target.

These scenarios do not reflect an attempt to forecast the most likely target-consistent outcomes, or even the most desirable 2050 outcomes. Rather they have been developed specifically to stimulate and test thinking on the appropriate market and regulatory models in 2050. Scenarios in which gas does not play a significant role were outside the scope of this work.

The sections below provide a brief overview of each of the scenarios and contrast them in terms of the high-level use of gas. More detail on each of the scenarios is contained at the start of each of the scenario-specific sections.

2.1 Description of the 2050 scenarios

2.1.1 High Hydrogen

The High Hydrogen scenario involves the conversion of all gas supply to hydrogen. In addition much of the road transport sector switches to use electric vehicles powered by hydrogen fuel cells (alongside some use of plug in electric vehicles), significantly increasing total national demand for gas. Overall, transport demand makes up almost a third of total hydrogen demand under this scenario. End use in buildings is mainly through use of hydrogen boilers that are similar to today's gas boilers.

The bulk of the current methane transmission network is maintained to feed domestic Steam Methane Reforming (SMR) facilities with imported methane, while peripheral elements of the network that are no longer needed are decommissioned. A separate hydrogen transmission network is constructed to interconnect the converted distribution networks and link them to the hydrogen production and import infrastructure. A high-pressure hydrogen network also serves some hydrogen filling stations. Other filling stations are supplied by tanker and there is a national road distribution network for hydrogen serving much of the nation's fuelling infrastructure.

The hydrogen itself is sourced from a combination of domestic production and direct hydrogen imports, which account for about 40% of demand. The bulk of domestic production is produced through SMR fed by imported methane and connected to carbon sequestration infrastructure. However, there is also significant domestic electrolysis production, some of which helps to supply off-grid transport demand. Imports are delivered through a combination of new hydrogen interconnectors and LNG-style import terminals. These link the UK to an international and liquid hydrogen commodity market.

2.1.2 Methane Peaking

The Methane Peaking scenario reflects a world that combines a steep supply curve for low carbon methane with prohibitively high hydrogen production and/or CCS costs. We assume that the cost of producing low carbon methane (both nationally and internationally) rises sharply as production increases, due to limits on the availability of low cost sustainable feedstock on the global market.

The resultant steep supply curve for low carbon gas means that its use in the energy system is restricted to supplying high-temperature industrial processes, where few low carbon substitutes are available, and for use in meeting peak heat demand, where it avoids the cost of building electricity generation capacity that is very rarely used.

The steep supply curve for low carbon methane means that aggregate heat demand is largely electrified through the widespread deployment of hybrid heat pumps[1], designed such that the gas boiler need only be used during the winter peak. The need for efficiency and the operational benefits of thermal storage also drive the comparatively widespread deployment of heat networks, which similarly rely on a combination of heat pumps and gas boilers, alongside waste heat, in order to meet demand.

The need to decarbonise industrial demand means that gas demand for high-temperature processes rises. The use of gas for power generation is effectively zero. Rising industrial demand combined with the displacement of gas elsewhere in the economy means that industrial use becomes a far more significant proportion of overall gas demand, making up more than half of total demand in 2050.

Only about half of total gas demand is produced domestically, through a combination of anaerobic digestion and syngas production facilities. The latter use a variety of feedstock, including domestic waste and biomass commodities like new wood[2]. The remainder of the gas required is imported through existing import infrastructure. Most, but not all, of these imports are sustainably-certified – a small proportion continues to be fossil natural gas.

2.1.3 Regional Gas Grids

The Regional Gas Grids scenario involves the separation of the existing national grid into multiple separate pipeline grids – one for hydrogen and a few others using low carbon methane. As with the Methane Peaking scenario, the cost of low carbon methane means it is not economic to use it to meet all the UK's heating and industrial demand. Consequently, the low carbon methane that is available is instead used to feed only a part of the total grid as it exists today. Alongside this, the UK realises significant shale gas production which, rather than being used

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1 We note that there are still major questions around the impact of hybrid heat pumps on gas and electricity consumption. A trial of these technologies is currently underway and will report in 2018. https://www.westernpowerinnovation.co.uk/Projects/Current-Projects/FREEDOM.aspx

2 For this scenario to be realistic, it is necessary to make assumptions about the availability of sustainable feedstock sources. We discuss these further in Section 5.

directly, is transformed into hydrogen and distributed using the remainder of the national distribution infrastructure, which is converted for this purpose.[3] Overall, about 70% of total demand for both gases is met from hydrogen; the rest is met by low -carbon methane.

Buildings end-use remains similar to today, with methane or hydrogen boilers used to heat water and provide space heating, although the improved average thermal efficiency of buildings helps to bring down space heating demand. The electrification of transport creates localised grid reinforcement issues, which creates new demand for the deployment of distributed electricity generation in the form of fuel cells or micro-CHP. The use of gas in centralised electricity production is almost completely displaced by the use of other technologies, but it retains a smaller but nevertheless significant role in decentralised power production. Industrial demand is also fairly similar, although many industries are converted to hydrogen.

Converted hydrogen distribution networks are interconnected and linked to sources of hydrogen production through the construction of a new hydrogen transmission system. Most methane distribution networks remain interconnected with one another, but a few are stranded by the hydrogen conversion process and are operated for the most part as standalone systems.

Domestic production of low carbon methane is identical to the methane peaking scenario, relying on a combination of anaerobic digestion and syngas production. Some low carbon methane is also imported, albeit a comparatively low level using existing import infrastructure.

Hydrogen is produced domestically at many SMR facilities, which are clustered in around five locations nationally. These facilities are linked directly to shale production and to a carbon network for sequestering the carbon they produce.

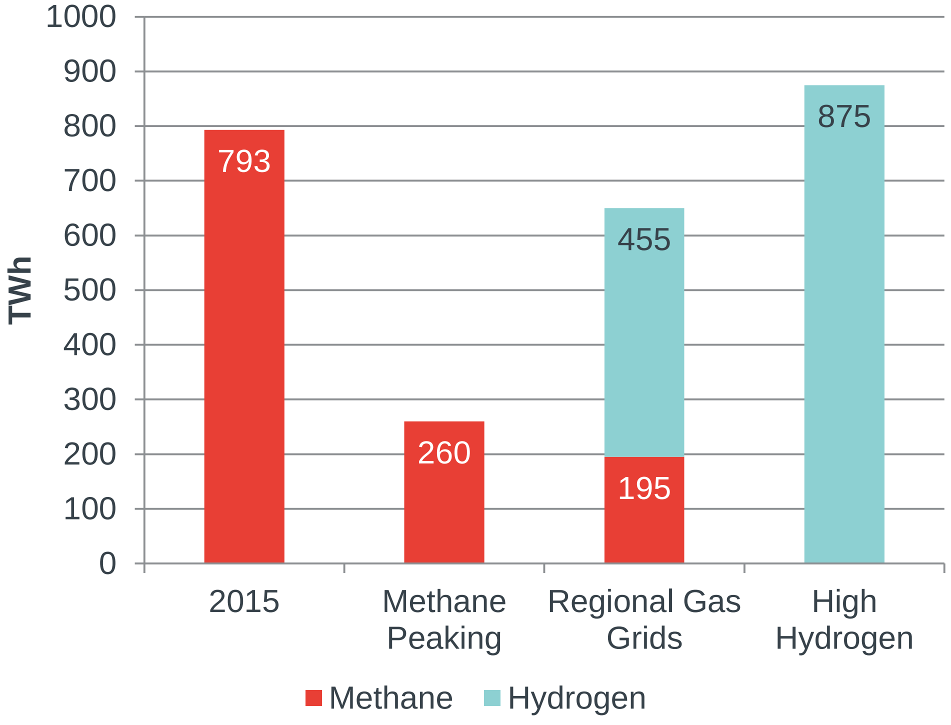
The need for domestic gas storage grows significantly, both because the UK is unable to rely on hydrogen imports from abroad and because the subdivision of the national network eliminates some risk pooling efficiencies, since each individual network must be independently secure.

2.2 Comparing the 2050 scenarios

Figures 1 and 2 below contrast the scenarios in terms of the scale and make-up of final demand. As can be seen in Figure 1, the overall level of gas demand varies markedly across the scenarios from Methane Peaking, where gas use is a fraction of current demand, to High Hydrogen, where the addition of transport demand implies that demand actually rises from now to 2050.

[3] Domestic hydrogen production could alternatively be supplied using imported methane and the use of domestic shale gas is not therefore a pre-requisite for domestic hydrogen production. However, to make the scenario conditions as explicit as possible we have assumed the use of shale in the case of the Regional Gas Grids scenario.

Figure 1 Final consumption of gas by scenario and type of gas

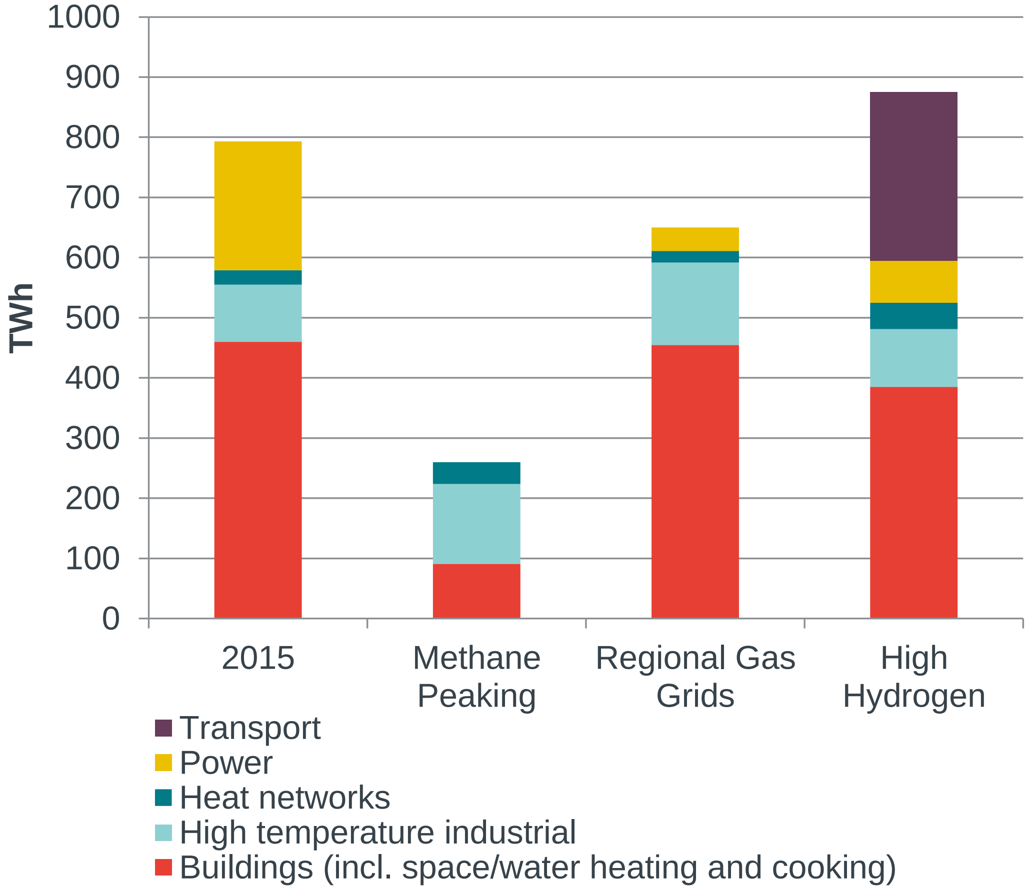


Source: DUKES 2016 and Frontier assumptions

Figure 2 shows how the composition of demand differs both across scenarios and relative to today. In all scenarios, the share of gas used in power generation is significantly lower than is the case today. The Regional Gas Grids and High Hydrogen scenarios both include a reduced use of gas in power production. This generation is mainly from decentralised generation using fuel cells and micro-CHP installations in the Regional Gas Grids scenario. In the High Hydrogen scenario this generation mainly comes from large-scale peaking generation.

High-temperature industrial demand plays a comparatively significant role in Methane Peaking, where other types of heat demand are largely electrified, but has a far less material role in the other scenarios. Heat networks also play a larger role in the Methane Peaking scenario. On the other hand, transport demand only becomes relevant in the High Hydrogen scenario, where it makes up nearly a third of total demand. These differences in composition both drive the seasonal profile of demand and help to define the nature of the market participants under each scenario. Further detail on all of the scenarios can be found in the opening section of each of the scenario-specific sections.

Figure 2 Share of final consumption of gas (methane and hydrogen) by demand type and scenario



Source: Frontier Economics

3 MARKET AND REGULATORY MODELS METHODOLOGY

In this section we provide an outline of the methodology used to develop the market and regulatory models. These models describe the entities involved in the provision of low carbon methane or hydrogen in the UK in 2050, from upstream production to consumer retail, as well as the contractual relationships between them. They are intended to provide a high-level vision of how the gas market could work in 2050. Each model was designed to be rational, efficient and sustainable given the scenario assumed. They were also intentionally developed without consideration of the transition to 2050 to ensure that the 2050 models were not biased towards current arrangements.

For each scenario, two separate models were developed. The first 'market-driven' model defaults to market-based arrangements where these could reasonably be used. The second 'additional-intervention' model is an iteration of the market-driven model, which explores the implications of greater government intervention where this might be beneficial to the functioning of the gas system.

The models themselves were constructed by drawing on the insights gained through two processes. A bottom-up process analysed information on the fundamental infrastructure, technology and demand side characteristics implied by each scenario. This analysis identified a series of issues and risks prevalent in each scenario, and began to develop potential market and regulatory structures that could be used to address these. A parallel top-down process involved close consultation with a broad range of experts, who provided advice on technical issues, financing, the industry and its regulation. The top-down process both widened the issues and risks identified, and added to and enhanced the potential solutions.

The insights from this work were then brought together in the market models, which are detailed in the coming sections (with further detail provided in Annex A). In each of these sections, we provide diagrams of the expected contractual flows, a description of the market arrangements and an explanation of why these arrangements are appropriate to the scenario considered. We also set out how the market-driven and additional-intervention models differ. Each scenario section concludes with a brief commentary that discusses the scenario's comparative benefits, how these might be realised by different stakeholders and the implications for the transition. Section 7 draws together some common observations and insights that span the scenarios and appraises them qualitatively against the criteria set out below. The appraisal covers the choices between the market-driven and additional-intervention variants, showing the trade-offs that can be made against various criteria by choosing to intervene.

Seven appraisal criteria are used, which were agreed at the outset of the project. These are as follows:

- **Efficiency** – Are goods and services produced at minimum cost, and are the right goods and services produced and given to those who value them the most?

- **Investment environment –** To what extent is the model likely to be able to secure investment in the necessary assets and infrastructure, at a cost of capital which minimises the cost to consumers?
- **Consumer protection and welfare –** To what extent are consumers able to choose freely and effectively among a wide variety of goods and services?
- **Political and consumer acceptability –** To what extent is the model likely to face marked political or public opposition, or to be politically infeasible?
- **Security of supply –** To what extent is the model likely to ensure that end users do not face either interruptions to supply or costly supply shortages?
- **Timelines –** How quickly can the model be implemented and does it imply lock-in?
- **Stability and flexibility –** To what extent is the model likely to be able to adapt and survive through changes to political priorities and objectives, technological costs and capabilities, and international market prices?

4 HIGH HYDROGEN MODELS

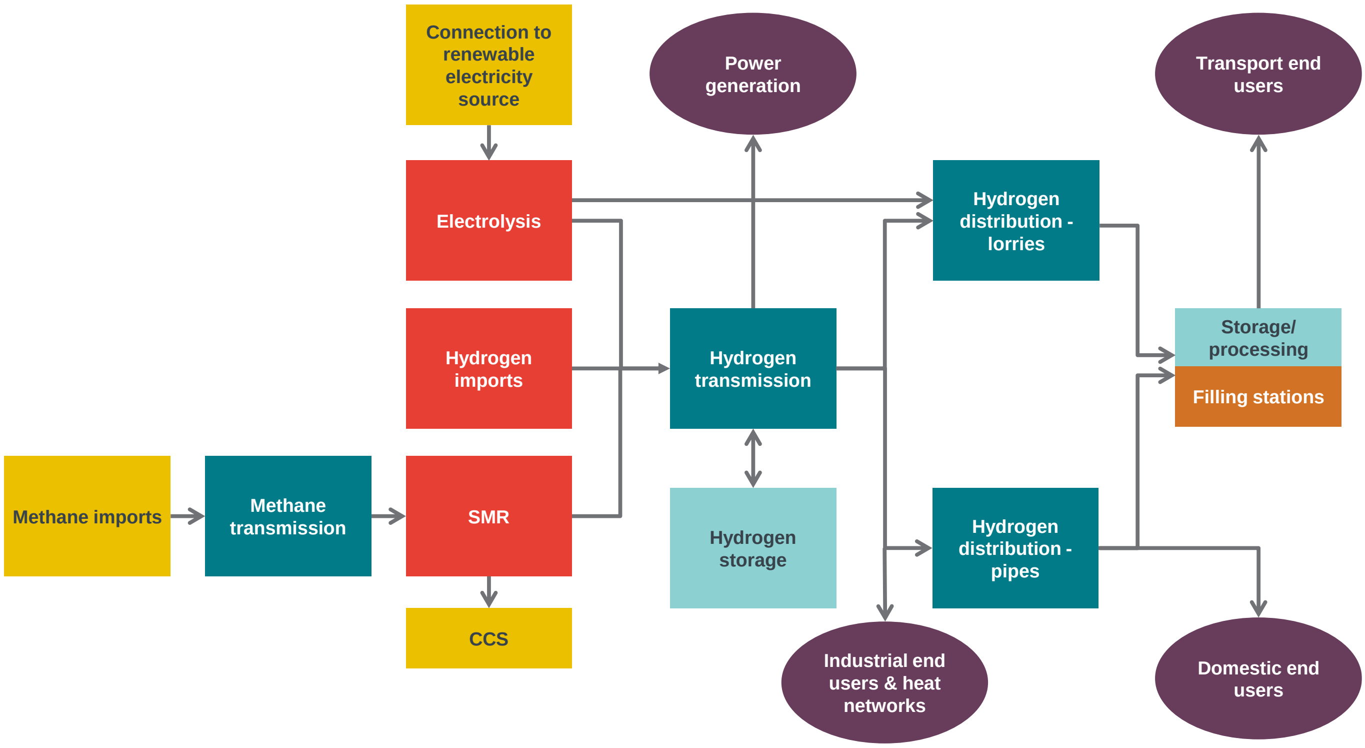
4.1 Attributes of scenario in the steady state

4.1.1 Overview

The High Hydrogen scenario is characterised by a complete repurposing of the gas network for hydrogen. Domestic production, from SMR and electrolysis, and imports meets demand. Gas is used in much the same way as today, with the exception of transport where hydrogen-powered vehicles become common, increasing overall demand.

Figure 3 shows the physical flows in this scenario.

Figure 3 High Hydrogen: Physical flows



Source: Frontier Economics

Box 1 describes the key conditions that would need to be in place for this scenario to be realised.

BOX 1: HIGH HYDROGEN: WHAT DO WE NEED TO BELIEVE?

Commodity markets and prices:

- There is a liquid international market for hydrogen and GB has sufficient import capacity to meet its needs from this market.
- GB has access to secure supplies of imported methane. These supplies need not necessarily be acquired on liquid and competitive international markets and instead could be sourced from overseas holdings.
- Imports compete with domestic production. They are the marginal source of supply and set the market price.
- The relative price of power and methane in GB, as well as the relative efficiencies of electrolysis and SMR production, are such that SMR accounts for most, but not all, domestic production.

Technology feasibility and cost:

- Hydrogen storage is feasible and sufficiently competitive, relative to increasing SMR or import capacity, that significant brand new capacity is built.[4]
- Hydrogen transport by road is cost-effective for some locations and so is used instead of extending the network.
- CCS is available for SMR facilities and its cost is suitably factored into these facilities' production costs.
- The sustainability case for the use of SMR and CCS is considered solid, despite the production of carbon.

Consumer preferences:

- Consumers are happy to take up and use hydrogen (e.g. perceptions around safety do not materially affect take up).
- For most consumers the overall cost of heating and utility of hydrogen is better than electrification and other heating technologies..

We now describe the assumptions that drive the market structure covering:

- upstream drivers;
- demand drivers; and
- networks and storage.

The gas system market models that result from these assumptions are described in Section 4.2 below.

4.1.2 Upstream drivers

Imported hydrogen makes up around 40% of total supply, with the remaining 60% coming mainly from domestic SMR production and some domestic electrolysis.

[4] For context, the UK currently has about 4.7 bcm of gas storage, of which 3.3 bcm is the Rough facility, which is due to close.

Imports compete with domestic production and set the marginal price, such that expanding domestic hydrogen production further is not economic.

In this system, the risk of cheap imports and alternative production technologies leads to volume risk for domestic production, and therefore exposes investors to stranding risk.

SMR plants

There are material upfront construction costs associated with domestic SMR plants. They require links to methane transmission, hydrogen transmission, and CCS networks. Because of this, the location of these networks is a major driver of siting decisions and implies that the plants are clustered in convenient locations.

Input methane is a large input cost to the production of hydrogen.

Electrolysis plants

Electrolysis plants require links to hydrogen transportation. They may also need links to power networks, though alternatively, they could be connected directly to renewable generation. Since they do not need to be connected to CCS, there exists greater locational flexibility relative to SMR plants, which allows for more distributed hydrogen production.

While construction is capital-intensive, the technology is readily scalable and allows for small-scale production. Electrolysis plants compete with SMRs. However, the assumed relatively high cost of electricity limits the overall contribution from electrolysis in this scenario.

Hydrogen import pipelines and terminals

Two new large liquid hydrogen import facilities are in place, with appropriate coastal geography determining the location of the terminals. A hydrogen interconnector to Norway is also envisioned and this imports around 200TWh of hydrogen annually. The import pipelines and terminals link to the hydrogen transmission network. The methane imports used to feed SMR plants is realised using existing LNG infrastructure.

Construction of this infrastructure is capital-intensive and, once constructed, the terminals have a significant opex cost. Much of the variable cost facing liquid hydrogen import terminals are losses in regasification, which are effectively taken out of production volumes.

The characteristics impacting on the market model are summarised in Figure 4.

Figure 4 High Hydrogen: Upstream components

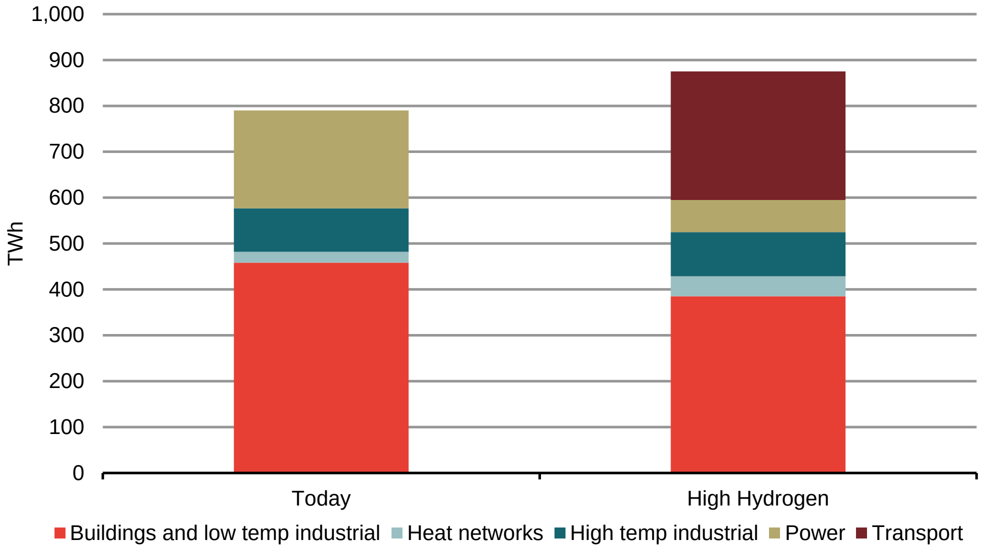
Technology or infrastructure	Presence in scenario	Characteristics	Links to other elements of the scenario and location requirements
SMR plant	Around 80 SMR facilities, each consisting of multiple reformers, with annual output of around 485 TWh.	Capital-intensive construction. Input methane is a significant running cost.	Requires links to methane transmission, hydrogen transmission and CCS networks. CCS networks largely determine location and imply clustering of facilities.
Electrolysis plant	Around 80 facilities of varying scales with annual output of around 40 TWh.	Capital-intensive construction but with adaptable scale, such that plants do not need to be large to be economic. Significant electricity cost, which limits the contribution from electrolysis.	Requires links to hydrogen transportation and power networks. No need for CCS provides greater locational flexibility and allows for more distributed hydrogen generation where useful.
Hydrogen import pipelines and terminals	Very significant new capacity, allowing for imports of 350 TWh and some seasonal profiling.	Very capital-intensive. Terminals have more significant opex than pipelines. A major variable 'cost' is losses in regasification, but this is effectively taken out of production volumes.	Requires links to hydrogen transmission network and, for terminals, appropriate coastal geography.

Source: Frontier Economics

4.1.3 Demand drivers

Total hydrogen demand is 875 TWh, which is higher than today's gas demand (790 TWh). Additional demand comes from the transport sector, where hydrogen is used to fuel most road transport. This increases baseload demand, meaning that, in relative terms, variation in peak to trough is smaller than today. The composition of total demand can be seen in Figure 5.

Figure 5 High Hydrogen heat demand



Source: Frontier Economics

Residential and low-temperature industrial

Demand from buildings and low-temperature industrial processes is met by hydrogen boilers and heat networks, which themselves use hydrogen boilers and waste heat[5]. Building demand is seasonal, owing to space heating requirements. Improvements in insulation and a greater need for cooling may reduce the absolute size of the winter peak relative to baseload demand.

High-temperature industrial demand

High-temperature industrial demand is a baseload source of heat demand over the year. Industrial demand is risky from a predictability perspective as it is made up of a relatively small number of large customers with a chance of going out of business or moving.

Power demand

Large-scale hydrogen generators provide some peaking generation[6]. The absolute size of this power sector demand varies based on these generators' positions in the merit order. Their demand profile is expected to be very peaky and linked to spikes in net power demand after accounting for non-dispatchable renewable generation.

Transport demand

In the High Hydrogen scenario, electric vehicles powered by hydrogen fuel cells are the main method of road transport, alongside a contribution from plug in electric vehicles. Transport demand for hydrogen is fairly constant throughout the year,

[5] Waste heat could be from industry and power stations located near centres of heat demand. In this scenario, we assume this is generally high-temperature waste heat, which can feed networks directly, (rather than low-temperature waste heat, which would need first to be upgraded by heat pumps).

[6] This is consistent with a generation mix dominated by inflexible or intermittent low carbon plants. If the generation mix is more flexible (because of a greater penetration of more flexible low carbon plant such as gas CCS or biomass), or if there is significant flexibility on the demand side, less hydrogen may be required for peaking generation.

and aggregate annual transport demand is relatively predictable and stable. Intra-day volatility in demand is linked to transport patterns.

These characteristics are summarised in Figure 6.

Figure 6 High Hydrogen: Demand Characteristics

Function	Quantity (proportion of total demand)	End use technology	Consumer choice	Predictability	Demand profile (peakiness)
Total demand	875 TWh (compared with 790 TWh today)		Hydrogen is the economic choice for most road transport and heating applications, hence its extensive use.		Around a third of demand comes from transport demand, which is broadly stable across the year. Although the absolute variation in peak to trough is similar to today, it is smaller in relative terms because of this new baseload source of demand.
Demand from buildings and low-temperature industrial demand	44% (compared with 58% today)	Hydrogen boilers	Customers can switch to electric heating, but face little incentive to do so.	Demand remains weather dependent.	Building demand is seasonal owing to space heating requirements. Improvements in insulation and a greater need for cooling may reduce the absolute size of the peak.
Demand from heat networks	5% (compared with 3% today)	Hydrogen boilers and waste heat	Fuel switching is possible, but there is little economic incentive to do so.	Demand remains weather dependent.	Similar to demand from buildings above.
High-temperature Industrial demand	Around 11% (compared with 12% today)	Various	Industrial consumers are assumed to have little ability to substitute for other low carbon energy sources.	Industrial customers remain relatively risky – large customers with a chance of going out of business or moving.	Baseload source of demand all year round.
Demand from the power sector	8% (compared with 27% today)	Large-scale hydrogen generation	These generators have no ability to fuel switch, but capacity could be provided by other technologies.	Demand varies based on position in generation merit order. Plants tend to be used for peaking.	Very peaky – linked to spikes in net power demand after accounting for non-dispatchable renewable generation.
Demand from the transport sector	32% (compared with 0% today)	Fuel cell hydrogen vehicles	Consumers have a choice of vehicle but hydrogen cars are not built to fuel switch.	Very predictable and stable demand in aggregate.	Fairly constant seasonal demand. Intra-day volatility linked to transport patterns.

Source: Frontier Economics

4.1.4 Networks and storage

The existing gas distribution network has been repurposed in the scenario to transport hydrogen, with the methane transmission system feeding imported methane to SMR plants for domestic hydrogen production. A new hydrogen transmission system is in place to link hydrogen production, storage and demand. The existing LNG infrastructure is retained for methane imports.

To support the transport sector, there is a nationwide system of hydrogen fuelling stations. This is supplied by a combination of physical and virtual pipelines (a national fleet of specialised lorries). There is assumed to be a relatively small capital cost for each lorry relative to network pipeline investments.[7]

Salt cavity storage with a capacity of 2bcm is in place to manage seasonal variation in hydrogen demand, with some operational methane storage used by SMRs. Alternatives to salt cavities, such as ammonia storage are also developed with a total capacity of 1.6bcm.

The key characteristics of the technologies are set out in Figure 7.

Figure 7 High Hydrogen: Network Components

Technology or infrastructure	Presence in scenario	Characteristics	Links to other elements of the scenario and location requirements
Transmission system	An NTS-like system is built, although fuelling station demand also results in more disbursed high-pressure network.		Interconnects SMR and electrolysis plants, import points, and converted distribution networks.
Distribution system	Converted existing distribution grids.	Fixed up-front costs need to be reimbursed. Comparatively small opex costs.	
Virtual pipeline	Effectively a national fleet of specialised lorries.	Relatively small capital cost for each lorry relative to network investments.	
Fuelling stations	Nationwide system of fuelling stations.	Capital investment is principal risk since fuel cost is readily passed-through. Scale of an individual investment is comparatively small relative to network investments.	Supplied either by lorry, or by direct grid connection.

Source: Frontier Economics

[7] Liquid hydrogen tankers are already commercially available and cost around £400k, although prices could fall to around £300k by 2050 according to work for the CCC. See 'Scenarios for deployment of hydrogen in contributing to meeting carbon budgets and the 2050 target', p.121.

4.1.5 Scenario commentary

The High Hydrogen scenario presents a 2050 energy system in which end user technologies are very similar to those today in terms of the consumer experience they provide. Despite involving some of the biggest changes in the transition, this scenario results in a situation in which consumers use heating and cooking technologies that are very similar to the current set-ups. Although plug in electric vehicles also form part of the mix, electric vehicles in this scenario are largely powered by fuel cells so are filled up at filling stations with energy-dense chemical fuel and have long ranges as a result. An important feature of this scenario, therefore, is how little the consumer experience varies before and after the transition.

Despite the need to replace the transmission system and to convert the distribution network in the transition, the nature of system operation is also very similar to today, with gas injected at a few major high-pressure sites and then flowed down to low-pressure demand. The absence of distributed generation technologies or hybrid heat pumps means that the interactions between the electricity and gas networks are relatively small in this scenario. Although electrolysis plants may create some interplay between gas and power, this takes place upstream, where market arrangements should help to dictate efficient behaviour, as they do already with the use of gas to generate power.

The upstream market becomes more complicated, owing to the need to transform either methane or electricity into hydrogen. However, market arrangements should be able to efficiently manage what is, in effect, a fairly normal production process. The bigger issue upstream is therefore likely to be the scenario's heavy reliance on the presence of a CCS network, which we assume is available when SMR investors want to use it.

4.2 Model summary and design rationale

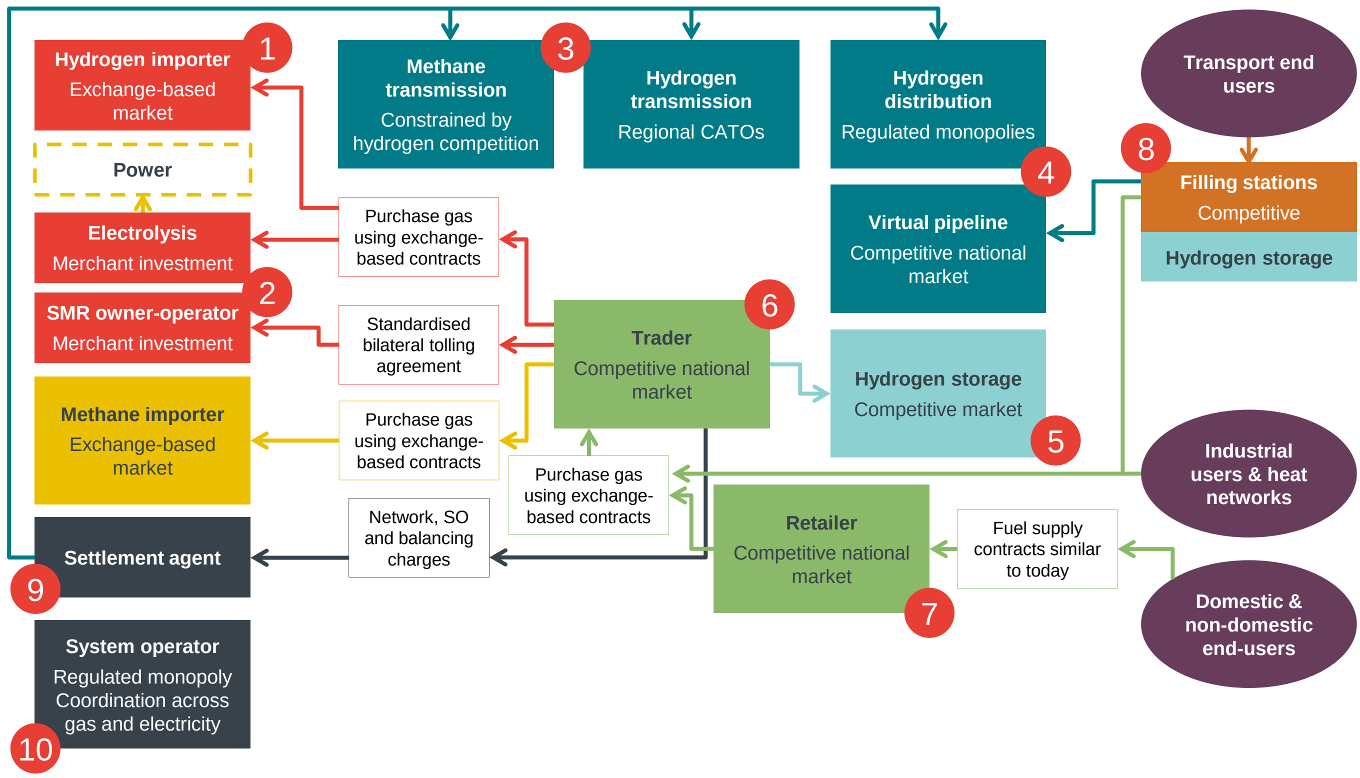
In the market-driven model, government intervention is limited to the management of major market failures. We first summarise this model, and explain the rationale for its design.

We then cover the additional-intervention model, focussing on where this differs from the market-driven model. As described in Section 3, the additional-intervention model is an iteration of the market-driven model, which explores the implications of greater government intervention where this might be beneficial to the functioning of the gas system.

4.2.1 Market driven model

Figure 8 describes the institutions and entities for a market-driven model for the High Hydrogen scenario, and the contractual flows linking them (see Annex A for detailed tables describing each entity). Note that the numbers in the diagram cross-refer to the relevant explanatory text.

Figure 8 High Hydrogen market-driven model



Source: Frontier Economics

Production and imports

We have assumed the existence of a liquid competitive international market for hydrogen **(1)** in this scenario, from which hydrogen is imported. Methane is also imported as an input for domestic SMR plants from an international market. These imports are assumed to work as they do today.

The domestic production market for hydrogen **(2)** consists of many SMR and electrolysis plants. The presence of a large number of plants presents the opportunity for competition in the production market, with the various domestic production technologies competing with each other and with international imports.

Domestic production technologies face volume risk in the production market, and therefore may engage in some horizontal integration across technologies in order to diversify commercial risk. Where this risk is fairly limited, production infrastructure can be financed using standard merchant financing arrangements.

However, we note that the appetite for merchant financing has tended to be relatively constrained in the UK energy market[8]. In well-functioning markets it is available but always at a premium of cost and with much lower leverage levels than "contracted" financings. If risk levels are higher and commercial finance cannot be raised at a reasonable cost, some form of government support for

[8] For example, Carrington Power went to the bank market seeking project finance debt for their CCGT project, and were ultimately unable to finance it. While there may have been many contributing factors, one recurring theme from financiers was the high level of merchant / uncontracted revenues in the project.

producers may be an attractive alternative[9]. We therefore discuss this issue and options for addressing it in the additional-intervention model, discussed in Section 4.2.2 below.

SMR plants operate under tolling agreements by which they sell conversion services to traders who own the methane input and hydrogen output. This helps to isolate SMR plant owners from directly having to interact in the methane and hydrogen commodity markets, passing this responsibility instead to the trader function for which these interactions are fundamental to its specialised role. It also means that SMR investors are not directly exposed to risks around commodity price fluctuations, since they do not take title to any of the gas themselves, though the creditworthiness of the traders is critical to their bankability. In this way, SMR plants are similar to present day LNG import terminals.

In contrast, electrolysis production sites are assumed to purchase power and sell hydrogen directly, so that gas traders do not also need to be active in the power market in order to contract with them. They may provide the electricity system with balancing and ancillary services and operate based on a business model that combines revenues streams from both the hydrogen and electricity markets.

Gas transport and storage

Methane transmission **(3)** operates similarly to today as a national monopoly. In the market-driven model, we assume that the existing NTS could be deregulated. Since the methane transmission exclusively feeds SMR plants in this scenario, and these plants themselves face competition from several sources, the charges that the transmission network can sustainably levy are limited by the need not to put these SMR plants out of business (effectively stranding the methane network). This constraint could potentially remove the need for price regulation. However, it should be noted that the network would still have monopoly power and could abuse its position up to the limits imposed by the need to keep the SMR plants in business. As a result, this situation doesn't prevent the scope for abuse, but merely limits its potential scale. SMR plant owners could also be vertically integrated with the network, presumably sharing joint ownership, to ensure that the network is operated efficiently and in a way that serves its users interests. This would resemble, for example, the way in which major UK banks co-own some of the payment systems that they use. Again however, this may not result in an efficient outcome, if it creates barriers to entry. In the additional-intervention model, discussed in Section 4.2.2 below, we include regulation of the methane transmission network (as under today's system) as an alternative solution.

In contrast, the rationale for regulating the hydrogen transmission network **(3)** would be similar as for the methane transmission network today, given its natural monopoly characteristics and the fact that it supplies household and other small customers' demand. In the market driven model, we assume that the construction

[9] The financing risk to hydrogen production is expected to be higher in this scenario relative to the Regional Gas Grid scenario, since multiple technologies and imports are all commercially competitive. Recently, a number of independent developers have approached the debt markets seeking funding for peaking / flexible generation plant, principally gas fired. They have faced similar challenges to Carrington - lenders are very happy to accept long term, contracted revenue under the Capacity Market, but much less willing to accept merchant or shorter-term, more unpredictable cashflows. These projects continue to discuss options with lenders, but it is clear that for most lenders, current bank appetite does not support more than a small proportion of the plant's income being merchant in nature.

of the hydrogen transmission network in the transition was carried out by a series of Competitively Appointed Transmission Owners (CATOs), which now own and operate distinct pieces of the network.

Hydrogen distribution **(4)** takes place either using the pipeline network or, predominantly in the case of filling stations, via a virtual pipeline of lorries that truck hydrogen to where it is needed. The pipeline networks consist of regional monopolies with regulated returns, much in the same way as the current methane grid. For the virtual pipelines, we anticipate the entry barriers to this form of distribution to be comparatively low. This supports a competitive market for virtual pipeline distribution, serviced by many specialised logistics companies. This competitive distribution service is also able to supply hydrogen to off-grid locations.

Hydrogen storage **(5)** operates in a similar way to current methane storage, with a sufficiently large number of storage sites helping to support a competitive national market. Investment in storage continues to be commercially financed and would reflect the need to meet typical seasonal fluctuations. However there is scope for a further intervention from the government to ensure adequate security of supply, as discussed in Section 4.2.2 below. The strategic risks arising from insufficient hydrogen storage are exacerbated in this scenario by the extensive use of hydrogen for transport and the ready access to imported energy. The latter may encourage the use of winter imports rather than domestic seasonal storage under this scenario, thereby reducing strategic security. For both these reasons, government intervention may be more likely.

Trading and operations

Traders **(6)** provide a critical role in this market, securing hydrogen from a range of sources and arranging for adequate storage or seasonal profiling of imports and production to meet demand. They purchase hydrogen directly from overseas markets, importers and electrolysis producers, while also arranging for the conversion of methane through the use of standardised bilateral tolling agreements with SMR plants. Much like today, the trader and retail functions may be integrated and coexist with independent traders.

The large number of participants in the market for hydrogen, and the presence of liquid international markets, implies that the national market for hydrogen is likely to be a competitive, exchange-based system. We envision that it operates similarly to non-locational NBP hub for methane.

Given the presence of multiple distinct network owners, the network and system operation payments are likely to be collected by a single settlement agent **(9),** as is the case today, in order to simplify the payment flows and contractual arrangements.

System operation **(10)** would be conducted by a single entity, as is the case today, balancing the system on behalf of all network users based on their notified positions. Under the market-driven model, the system operator is assumed to be a privately-owned regulated monopoly, as it is today. The nature of the system operator's role requires it to be a single body for reasons of operational necessity, thereby requiring a minimum level of regulation if it is to be privately-owned. There is scope for varying degrees of intervention in terms of the ownership model for the system operator, as discussed in Section 4.2.2 below.

Retail

The presence of multiple sources of hydrogen production and competition at the wholesale level allow for a competitive retail gas market **(7).** It operates in a similar manner to today's methane market, with regulated supplier switching. Retailers have fuel supply contracts with domestic and non-domestic end users, under which end users are charged in relation to the volume of gas that they use.[10]

There is potential for retailers to develop propositions that span both building and filling station use in this scenario, which could result in more innovative retail offerings, discussed below.

Transport

The extensive use of hydrogen in transport results in the need for a market for fuelling. A national network of hydrogen filling stations **(8)** supplies private customers in a competitive fuel market. These fuel stations are serviced either by the pipeline network, or else by the competitive 'virtual pipeline' market mentioned previously.

As driving services companies make up a large share of journeys, the possibility of a fleet vehicle model may emerge. In this case, several large collectives each would own substantial vehicle fleets, which may affect market bargaining dynamics by introducing significant buyer power. However, this would not directly affect the overall competitiveness of the market for hydrogen fuel supply in the transport sector.

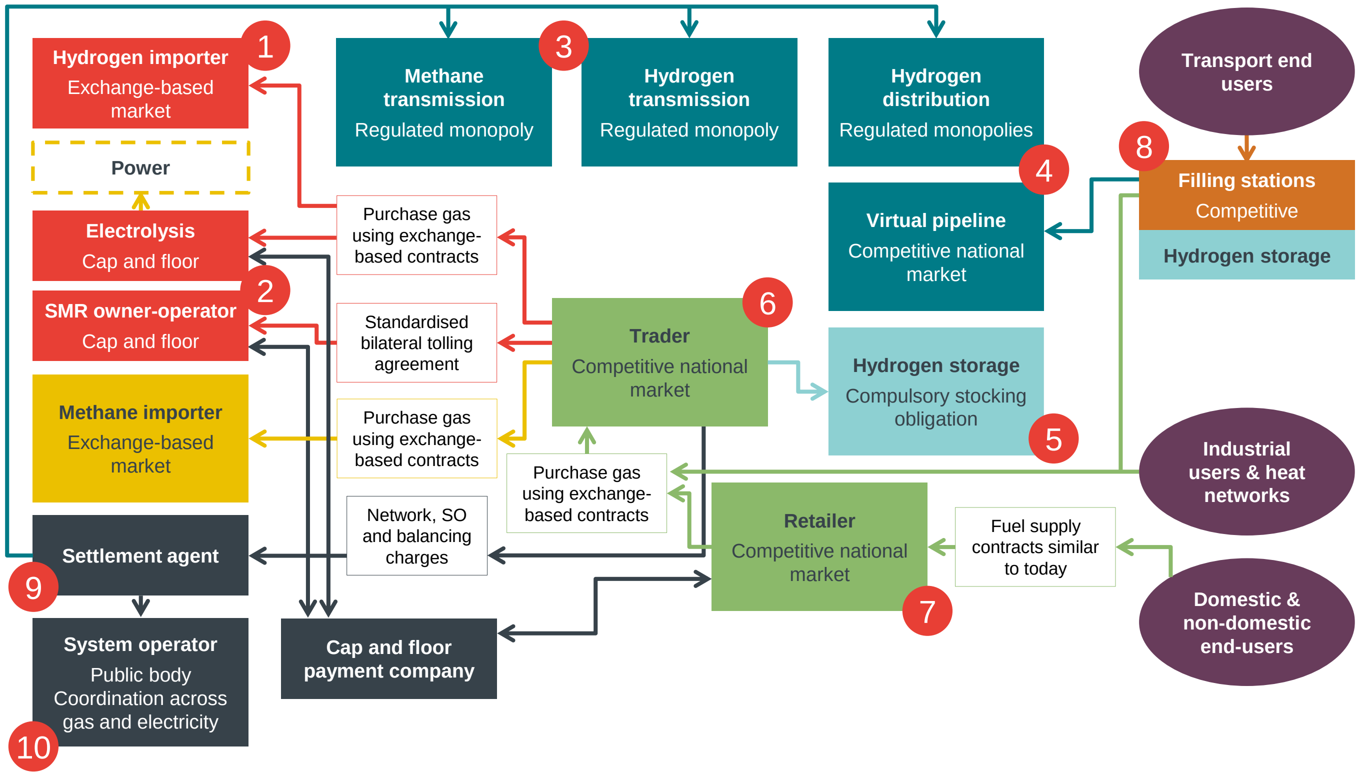
Even for individual household consumers, it may be that a single supplier would provide a contract to cover hydrogen used in both the home and for vehicle use (for example, if filling stations were not branded to a single supplier, but could instead be visited by customers of multiple different suppliers).

4.2.2 Additional intervention model

As described in Section 3, the two models we have developed for each scenario have similar structures but differ in the extent of government intervention. We now present the additional-intervention model (Figure 9) and describe how this differs to the market-driven model.

[10] In the High Hydrogen case, we do not envisage significant developments to retail propositions. This reflects the assumptions about end use technologies in this scenario. Specifically, since hydrogen boilers will not result in any interactions with the power sector, there is less scope for viable propositions that cover heating alongside a wider set of energy services. In contrast, the Regional Gas Grids scenario includes domestic fuel cells and micro-CHP, and the Methane Peaking scenario includes hybrid heat pumps. These technologies tend to be more capital-intensive and also interact with the electricity sector. We discuss the consequences of this for retail propositions in Sections 5.2 and 6.2.

Figure 9 High Hydrogen additional-intervention model



Source: *Frontier Economics*

The additional-intervention model includes the following additional features.

- **Upstream investment support (2)** – In the market based model, we have assumed that the investment risks facing investors in SMR and electrolysis are manageable, such that standard merchant financing and investment is possible. Given the characteristics of these technologies as set out in Figure 4 above, this would be plausible in the steady state in a well-functioning market. However, if these investment risks were viewed by the market as so significant that commercial finance could not be raised at reasonable cost, a public support mechanism could potentially be used as a means to bring about investment more cheaply, while exposing consumers/taxpayers to some degree of risk. There are many options for providing investment support. One example would be a cap and floor arrangement, which would limit the risks investors face around returns they gain from investment in the SMR infrastructure. A Contract for Differences (CfD) regime would be another option. However, since SMR facilities are investing in infrastructure and selling conversion services (rather than directly selling the hydrogen they produce), a CfD, which is linked to the relevant commodity price, would be less appropriate here.
- **Regulation of the methane transmission network (3)** – As noted above, though the need to keep SMR plants in business limits the prices the methane transmission network can charge, there could still be scope for some abuse of monopoly power in a deregulated methane transmission network. In the additional-intervention model, we therefore include regulation of the methane transmission network (as under today's system).

- **A single monopoly for the hydrogen transmission network (3)** –The market-driven model includes a set of CATOs running the hydrogen transmission network. In the additional-intervention model, a single national transmission owner is in place, as is the case with the methane transmission system today. Either way, the relevant owners are regulated networks and subject to the sorts of regulatory framework that exists today. The main difference is that, because there are multiple owners under the CATO model, different regulatory approaches might be available to the regulator. For example CATOs would make benchmarking of performance among the owners a viable proposition and allow for competitive regulatory rewards. CATOs may however also lead to inefficiencies in the planning and operations of the national network, which is split among numerous parties.

- **Intervention to incentivise storage (5)** – Although the fundamentals of investments in gas storage allows for storage to be commercially provided through a competitive market, as it is today, the quantity of hydrogen that traders choose to store ultimately reflects the financial costs they face in the event of a shortfall. These costs may not naturally include the wider strategic implications of being unable to fuel road transport for example, and therefore fall short of a fully efficient level. Even if these costs were elevated to a level reflective of the national costs of undersupply, for example through the imposition of a regulatory scarcity price for unmet demand, traders may not appropriately account for the risk of infrequent or unprecedented market shocks, or of a sudden reduction in market liquidity in the event of a serious shortage of supply. Because of these risks, the Government may prefer to intervene in an attempt to enhance security of supply by, for example, setting out a minimum amount of gas that must be stored. There are many options for how this could be achieved. For example, compulsory stocking obligations like those that exist for petroleum products could be used, with the storage obligation effectively dispersed among retailers and the cost passed ultimately to consumers. Provided secure and flexible arrangements are in place for meeting the obligation, the effect of the obligations is simply to boost aggregate demand for storage to the appropriate level, with delivery still achieved through competitive market processes. We note that security of supply could potentially also be enhanced through other means, like building additional production and import capacity, and that, ideally, it might be more efficient to develop a security product that could be arbitraged across all these potential sources of gas supply. However, this approach would be untested and require significant policy development to ensure its effectiveness.

- **Further intervention on system operation (10)** – Under the market-driven model, the system operator is assumed to be a privately-owned regulated monopoly, as it is today. The nature of the system operator’s role requires it to be a single body for reasons of operational necessity, thereby preventing a fully market driven approach and requiring a minimum level of regulation if it is to be privately-owned. However, the role of the system operator is likely to change over time, requiring it, for example, to contribute to or coordinate independent network planning across multiple energy vectors and networks. Developing regulatory incentives to motivate efficient cross vector planning in this context could be challenging, particularly as the system operator has a natural incentive to favour reliance on assets and processes that it controls and is remunerated for when making any planning decisions. The Government may therefore conclude that system operation requires much closer oversight, or even that this function should be conducted by a public body.

4.2.3 Comparison to today's models

In the 2050 steady state, market models for High Hydrogen do not look radically different to today's market (Box 2).

BOX 2: COMPARISON OF THE 2050 MODELS WITH TODAY'S

Upstream:

- Gas continues to be competitively exchange-traded. A new exchange is established for hydrogen that effectively mirrors today's natural gas market.
- Energy imports are highly important, both in the form of imported hydrogen and imported methane feedstock for SMR.
- The upstream hydrogen market incorporates a large number of comparatively small-scale producers, relying on multiple production technologies.

Networks and storage:

- Network regulation for the methane NTS is different from today under the market-driven model, since revenue regulation is removed entirely. For the new hydrogen transmission network, it is owned by multiple parties, allowing for the benchmarking of performance.
- In the case of filling stations, pipeline networks face direct competition from road-based transport networks, although these are only used in practice where pipeline supplies are not available.
- In contrast, the additional-intervention model sees revenue regulated monopoly transmission networks in a way that is similar to today.
- The storage market works in a similar manner to today's. Demand is underpinned by Government stocking obligations in the additional-intervention model.
- System operation increases in complexity, with the increased requirement to coordinate across multiple energy vectors and networks. Under the market-driven model, the system operator is a privately-owned regulated monopoly, as it is today. In contrast, under the additional intervention model, there is either increased oversight of the privately owned monopoly, or a move to a publicly-owned system operator.

Downstream:

- The retail market is not very different to today, with charging based on metered volumes used.
- Retail propositions might emerge that cover both building and transport use, since both use hydrogen.

4.2.4 Uncertainties

The design of the market models in the steady state described above is driven by a set of assumptions within the scenarios. Given the uncertainty around these assumptions, it is useful to consider the impact on market models of relaxing the most significant of these.

- **The upstream market could remain competitive, even without imports.** Imports are assumed to make up 40% of demand in High Hydrogen. Without these imports, domestic gas production capacity would have to increase by at least two thirds. While the absence of imports would reduce the likelihood that a transition the High Hydrogen scenario by 2050 would be feasible (see Section 8), the cost structure of hydrogen production plants means that is likely that upstream gas production markets could still function competitively without imports. Even without imports of hydrogen to set the marginal price, there would still be multiple small producers competing on price.
- **Without imports, deregulation of the methane transmission network would be riskier.** However, deregulation of the methane network would be riskier in a world without imports, as if SMR production only competes with electrolysis, the scope for over-pricing by a monopoly network could be greater (see Section 4.2.1 above). In addition, without imports, SMR may have to play a larger role in the gas system. This means that any over-pricing would be potentially more significant for the economy as a whole.
- **If SMR with CCS is costly or infeasible, the case for greater coordination with the electricity sector or compulsory stocking obligations may be strengthened.** The High Hydrogen scenario assumes that it is generally most cost-effective to produce hydrogen from methane using the SMR process and that CCS to capture the emissions is feasible[11]**.** If SMR with CCS is more costly (for example due to high methane prices) or infeasible (for example, due to issues with CCS), domestic electrolysis production or imports would need to play a greater role. While this would not fundamentally change the market model, to the extent that electrolysis plays a greater role, arguments for greater coordination between the electricity and gas systems would be strengthened. A greater reliance on hydrogen imports may strengthen the case for compulsory stocking obligations, to reduce geopolitical risks around security of supply.
- **If only limited hydrogen storage is cost-effective or feasible, additional support for upstream investments may be required.** The High Hydrogen scenario assumes that that significant new storage capacity (3.6 bcm) has been built in the transition.[12] If this was not feasible, additional SMR, electrolysis or import capacity would need to be put in place to meet seasonal demand peaks. Since these plants would only be expected to run for a relatively short period, very high peak prices would be required to make these plants financially viable. If these were either not expected, or felt to be socially unacceptable, additional capacity support for upstream production or import capacity (for example, via the cap and floor mechanisms discussed in Section 4.2.2 above) may be required.

[11] 12 times as much hydrogen is produced using SMR relative to electrolysis in High Hydrogen.

[12] For context, the UK currently has about 4.7 bcm of gas storage, of which 3.3 bcm is the Rough facility, which is due to close.

5 METHANE PEAKING MODELS

5.1 Attributes of scenario in the steady state

5.1.1 Overview

The Methane Peaking scenario reflects a world that combines supply constraints on the volume of low cost, low carbon methane with prohibitively high hydrogen production and/or CCS costs.

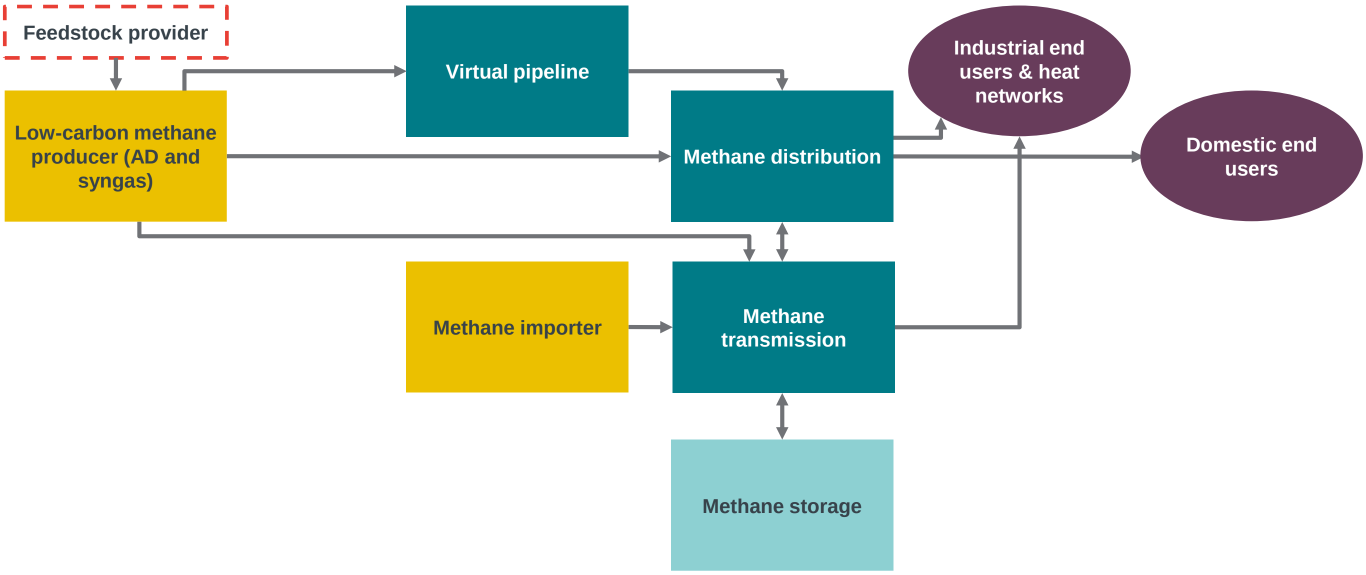
We assume in this scenario that the cost of producing low carbon methane (both nationally and internationally) rises sharply as production increases, due to limits on the availability of low cost sustainable feedstock on the global market. The resultant steep supply curve for low carbon gas means that its use in the energy system is restricted to:

- **Where alternative low carbon options are not available** – Around half of the gas is used in high-temperature industrial processes.
- **As a back up to electric heating in buildings, to reduce peaks on the electricity system** – Heat is largely electrified through the widespread deployment of hybrid heat pumps and heat networks that use a combination of heat pumps and gas boilers.

About half of the gas required is supplied through domestic AD and syngas production, but there are also extensive imports of methane, most of which is low carbon-certified but some of which is fossil.

Figure 10 shows the physical flows in this scenario.

Figure 10 Methane Peaking: Physical flows



Source: Frontier Economics

Box 3 describes the key conditions that would need to be in place for this scenario to be realised.

BOX 3: METHANE PEAKING: WHAT DO WE NEED TO BELIEVE?

Commodity markets and prices:

- Electric heating is cheaper than gas-fired heating for most of the year, but gas-fired heating becomes more cost-effective during the winter peak.
- There is a liquid international market for low carbon methane.
- GB has access to sustainable international sources of feedstock for use in the production of syngas. These supplies need not necessarily be acquired on liquid and competitive international markets and could alternatively be sourced from overseas holdings.
- Domestic production of low carbon methane cannot be expanded further without becoming more costly than imported supplies of low carbon methane.

Technology feasibility and cost:

- There is sufficient sustainable feedstock available to enable the required production of low carbon methane and this is the best use of this feedstock given the potential alternative uses available.
- Trailer-based methane storage and transport makes off-grid methane production commercially viable.
- Hybrid heat pumps are able to electrify the majority of heat demand where they are used and can flex their relative use of electricity and gas to some degree in response to price signals.
- The functionality and performance of hybrid heat pumps improves to the point that they are attractive to the majority of consumers.
- The power sector can support the electrification of most heat demand from buildings.

Consumer preferences:

- Most on-grid consumers are able (and willing) to switch to hybrid heat pumps or heat networks.

We now describe the assumptions that drive the market structure covering:

- upstream drivers;
- demand drivers; and
- networks and storage.

The gas system market models that result from these assumptions are described in Section 5.2 below.

5.1.2 Upstream drivers

Low carbon gas production in this scenario is characterised by a mix of competing sources of low carbon gas, including imports from liquid international markets, and capital-intensive domestic production. All of these sources are economic at the prevailing gas price and they compete with one another. Domestic production is assumed to be cheaper than importing low carbon gas, up to a certain level of production (after which the costs of importing feedstock render it uneconomic)[13]. Import prices set the marginal price of gas and expanding domestic production, for example by importing more feedstock, is not economic.

Figure 11 describes upstream gas production in more detail. Key things to note include:

- given the competing sources, and the potential for multiple players within each market, a competitive upstream market is possible;
- the flipside of this is that investors in capital-intensive domestic gas production face volume risk; and
- where production is based on waste, feedstock markets are likely to be local and may not be liquid, driving further risks that investors or Government need to manage.

[13] We consider the impact of assuming that imports are cheaper in Section 5.2.4 below.

Figure 11 Methane Peaking: Upstream

Technology or infrastructure	Presence in scenario	Characteristics	Links to other elements of the scenario and location requirements
Anaerobic digestion plant	250 AD plants producing around ≈30 TWh of methane.	Capital-intensive plants processing local wet waste (farm waste, food waste or sewage sludge). Most economically efficient to run baseload, but output can be varied with demand.	Location of wet waste source is likely to drive the location of the plants. Needs to link up to methane distribution or transmission network, or to a virtual pipeline. Competes with syngas plants and imports.
Syngas plant	165 syngas plants producing ≈100 TWh of methane. Mixture of 60 biomass and 105 waste plants	Capital-intensive plants processing waste or bio-feedstock. Bio-feedstock comes from liquid national and international markets (unlike AD). Most economically efficient to run baseload, but output can be varied with demand.	Needs to link up to methane distribution or transmission network, or to a virtual pipeline. Competes with AD plants and imports.
LNG import terminals	Existing LNG import terminals continue to be used – importing around 130 TWh of low carbon methane.	Liquid international market. Marginal source of gas in this scenario (generally more costly than domestic production).	Needs to link up to methane distribution or transmission network, or to a virtual pipeline. Competes with domestic production.

Source: Frontier Economics and Aqua Consultants

Anaerobic Digestion (AD)

AD plants are capital-intensive plants that process local wet waste, including farm waste, food waste, or sewage sludge. The wet waste source has a low energy density and is expensive to transport. The location of the wet waste source is therefore likely to drive the location of the plants, which need to be connected to the methane transmission or distribution network. In places where pipes are not cost-effective, virtual pipelines in the form of truck fleets can be used to transport the methane.

The plants are most economically efficient when running at baseload; however output can be varied with demand. In this scenario, methane produced by anaerobic digestion competes with imports and other forms of domestic production.

Syngas plants

Syngas plants are capital-intensive and process waste or bio-feedstock. Some of this feedstock can be relatively easily transported and comes from liquid national and international markets. The plants must be linked with the methane distribution or transmission network, or to a virtual pipeline. They compete with AD and imports.

Like AD plants, it is most economically efficient to run syngas plants at baseload but output can be varied with demand.

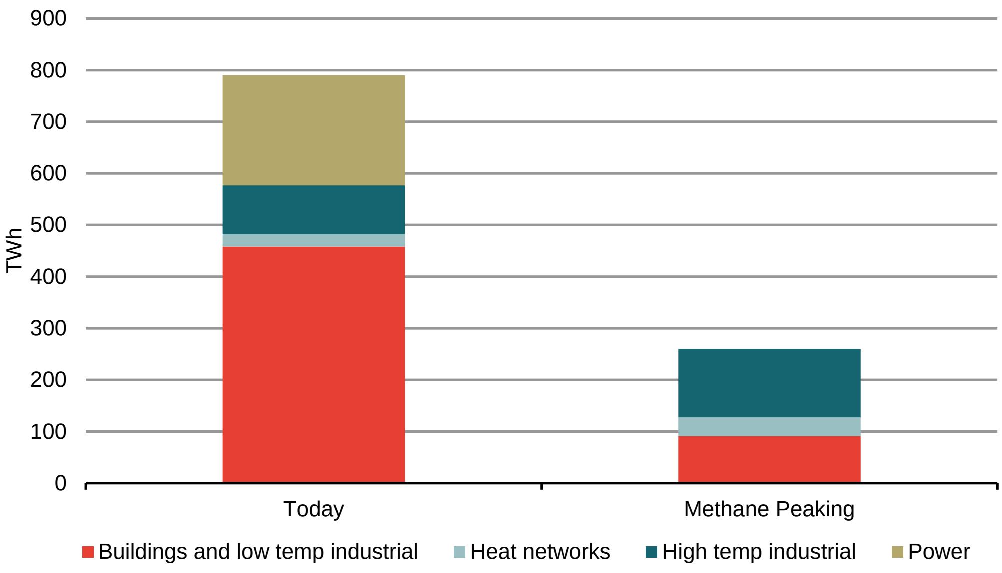
Imports

Methane imports are sourced from a liquid international market. As described above, imports set the marginal gas price in this scenario.

5.1.3 Demand drivers

Total demand for gas in this scenario is 260 TWh, compared with 790 TWh today (Figure 12). Around 50% of demand is baseload (from industry). The remainder, used to supply peak heating in buildings, is subject to acute seasonal peaks. Gas is comparatively expensive but constraints on electricity sector capacity mean that, for many customers, at certain times of year it becomes the preferred fuel for space heating. At the same time, some customers choose to use gas all year round. For example, this could be based on their preferences for more responsive hot water heating. Industrial consumers who remain on gas do not have an ability to fuel switch.

Figure 12 Methane Peaking gas demand[14]



Source: Frontier Economics

Figure 13 describes demand in more detail. Key drivers of market structure include the following:

[14] While some customers may use gas all year round these figures assume that it is used by the majority for winter peaks only.

- Overall demand is significantly lower than today, but peak demand is at a similar level. This reflects the fact that on the coldest days of the year, when demand is at its peak, hybrid heat pumps switch to gas consumption to provide space heating. In addition, fuel switching to gas in industry may offset reductions in consumption elsewhere, for example reductions driven by improvements in insulation. Since the capital costs of the infrastructure must therefore be spread over fewer units of actual gas, the system as a whole is more capital –intensive.
- Generally demand is less predictable and its peaks are more acute, because gas heat demand only services the very coldest days and demand therefore depends heavily on the unpredictable number of very cold days that occur during winter. Also, because a large amount of baseload demand feeds industrial users, who may go out of business or relocate, retailers may be less sure of their customer base. Vertical integration with retailers may be a less effective strategy for managing producers' volume risk than today as a result.
- Buildings customers have some ability to fuel switch in the short run in response to changes in prices, since hybrid heat pumps can run on either gas or electricity. In addition, new more capital-intensive end use technologies are required, many of which interact with the electricity sector.

Figure 13 Methane Peaking: Demand characteristics

Function	Quantity (proportion of total demand)	End use technology	Consumer choice	Predictability	Demand profile (peakiness)
Total demand	260 TWh (compared with 790 TWh today)[15].		Gas is comparatively expensive but constraints on electricity sector capacity mean that at certain times of year it becomes the preferred fuel for buildings consumers. Industrial consumers who remain on gas do not have an ability to fuel switch.		Around 50% of demand is baseload. The remainder is subject to acute seasonal peaks.
Demand from buildings and low-temperature industrial demand	35% (compared with 58% today).	Hybrid heat pumps.	In the longer term, consumers could choose to switch to electricity. Short term fuel switching is limited during cold snaps due to the electrical capacity of the heat pumps.	Customers have some (limited) ability to switch to electricity, though this would require upgrades to their end use technologies. Demand remains highly weather dependent.	Highly seasonal, and peaks are more acute than today. Many customers only use gas during cold snaps or periods of very high electricity prices, though some use it all year round for hot water.
Demand from heat networks	14% (compared with 3% today).	Gas boilers to back up heat from heat pump and waste sources.	In the longer term, heat network consumers could choose to switch to electricity.	Demand remains highly weather dependent.	Highly seasonal, and peaks are more acute than today. Only occurs during cold snaps or periods of very high electricity prices.
High-temperature Industrial demand	Around 51% (compared with 12% today).		Industrial consumers who remain on gas do not have an ability to fuel switch.	Industrial customers remain relatively risky – large customers with a chance of going out of business or moving.	Baseload source of demand all year round.
Demand from the power sector	None.				

Source: Frontier Economics

[15] While some customers may use gas all year round these figures assume that it is used by the majority for winter peaks only.

Buildings and low-temperature industrial demand

Hybrid heat pumps and heat networks are generally used to meet residential, building, and low-temperature industrial heat demand though some consumers will use either gas or electricity alone all year round, and other customers may use electricity for space heating, and gas for hot water heating.. The resulting demand profile for gas from buildings is highly seasonal and weather dependent, with peaks occurring during cold snaps or periods of high electricity prices. These peaks are more acute than those experienced today. Further analysis of the drivers and outcomes of fuel switching is set out in Box 4 below.

Heat networks are used extensively in this scenario, powered mainly by heat pumps and waste sources backed up by gas boilers.

High-temperature industrial demand

High-temperature industrial demand is a baseload source of demand all year round.

Industrial customers are a comparatively uncertain form of demand for retailers because they risk going out of business or relocating their operations. They also tend to be large individual consumers, with changes in the fortunes of the supplier's industrial customer base less likely to average out over the customer base as would be the case for domestic consumers.

BOX 4: BUILDINGS DEMAND: FUEL SWITCHING

What drives the choice between gas and electricity to heat buildings in this scenario?

Consumers make two types of choice between fuels in this scenario: once every 10 - 20 years they choose a heating system to invest in; and if they choose a hybrid system, they then make ongoing decisions on fuel use as long as they have the system operating.

Major drivers for their choices in each case include the relative costs of gas and electric heating, risks around future commodity prices, their preferences for the type of heating technology or fuel type and technical constraints. These drivers are likely to vary across the population and across time (Figure 1).

Figure 14 Drivers of choice

	Investment decision	Ongoing fuel use
Relative costs	Actual capital costs, projected efficiency (in a given property type) and projected costs of accessing the required fuel	Actual efficiency and costs of accessing the required fuel
Risk	Exposure to future commodity prices or risks around security of supply (where a technology that can use more than one fuel can help manage these risks)	
Preferences	Technical characteristics of the heating system (such as responsiveness, noise, space required, lifestyle, familiarity of the system	Technical characteristics of the heating system (such as responsiveness, noise).
Technical constraints	Property characteristics such as space constraints, heating requirements	Characteristics of the heating technology (such as its ability to meet peak demand)

Source: Frontier Economics

What do we assume about the outcomes of consumer choice in this scenario?

Based on these major drivers, consumers will be expected to take up the following technologies.

- **Hybrid system (optimised heat pump capacity):** This is a system that is made up of a heat pump sized below the requirements of peak winter demand, and a gas boiler for use during system peaks. By choosing a heat pump with a lower capacity, consumers save on both the upfront costs of the heat pump and any cost-reflective connection charges to the electricity network. The gas boiler gives them the capability to switch to gas. In the Methane Peaking scenario, this system is assumed to be the most cost-effective solution for the majority of consumers that also meets their preferences. We assume that most users of this hybrid system use electricity for space heating for most of the year, only switching to gas to heat their homes during the winter peak, when electricity prices are high. In fact, since the heat pump part of their system is sized below the level required to provide sufficient heat during the whole winter peak (taking into account the impact of cold weather on system performance), for some of the peak period, they may have to switch to gas in order to adequately heat their homes. While the hybrid systems are designed for gas to be mainly used at peak time, consumers may choose to use the gas part of their system more often, particularly for hot water, for example, because they prefer its responsiveness (and are willing to pay a higher price for this).

- **Hybrid system (large HP capacity):** Some consumers could choose to invest in hybrid systems with a larger heat pump capacity, despite the higher up front cost associated with these. They might do this if they wished to retain the choice to use either gas or electricity all year round. Again, consumers with these technologies may also choose to use the gas part of their system outside the winter peak.
- **Single system:** Some consumers could choose to invest in a single system (either electric HP or gas boiler) that uses a single fuel all year round. They might make this choice because the particular characteristics of their property or lifestyle means that this is cost-effective, or because they have a preference for one type of heating system and are willing to pay higher costs.

What is driving changes in the relative cost of gas and electricity?

Changes in the demand and supply of both fuels will drive changes in their relative prices, and therefore the costs of heating and hot water. On the demand side, this will be driven by consumers' choice of technologies, and then the way that they choose to operate them in response to the relative prices they face. In the Methane Peaking scenario, we assume that most consumers have hybrid systems that are generally running when the price of gas is below the price of electricity.

On the supply side, this scenario assumes that the higher costs of producing low carbon methane (together with the technical performance of heating technologies) means that, for most of the year, heating with gas is more costly than heating with electricity[16]. However, a large differential in seasonal energy demand (driven largely by demand for heat), combined with a lack of seasonal storage options for electricity, means that this relativity changes during the winter peak: as the electricity system gets close to peak capacity, electricity prices rise[17], and gas becomes the cheaper fuel.

The length of the period during which gas is cheaper than electricity varies each year (depending on factors such as the underlying commodity prices, where the investment cycle each sector is and the temperature). For the purposes of this scenario we assume that gas becomes cheaper (and is therefore used) for most domestic consumers during peaks in demand associated with cold snaps (which could be for a few days or weeks each year).

[16] As described above, in this scenario, we also assume a steep supply curve for low carbon gas, meaning that its price increases sharply as more production is required to meet demand.

[17] Given the lead times associated with investment in all new electricity sector capacity, this is likely to hold for a wide range of electricity generation scenarios.

How would consumers respond to changes in the relative costs of gas and electricity?

For markets to work efficiently in this scenario, consumers would need to have the means to respond to relatively short term (e.g. hourly or daily) changes in the relative cost of gas and electricity. Two developments are important to facilitate this.

- We assume cost reflective time of use tariffs (e.g. varying hourly or daily) are in place for consumers with hybrid systems. These send a relatively granular and accurate price signal to consumers, allowing them to make an efficient switching choice.
- We also assume smart technologies facilitate this switching. This means that consumers can rely on an automated response to price signals (with an override function available), rather than expecting them to devote daily or hourly attention to changing prices. Smart technologies (such as smart plugs for electric vehicle charging) are already on the market, and the expectation is that they will be deployed as a cost-effective solution for all systems by 2050.

Could there be a role for regulatory approaches, to ensure gas remains affordable to meet peak heating demand?

As described above, it is possible that some consumers will prefer to use gas all year round, even if this means they pay more for their heating and hot water systems. This could include consumers with a gas only system, or consumers choosing the use the gas part of the hybrid system (by 'overriding' price signals). Given the steep supply curve for gas assumed in this scenario, this use pattern could have a significant impact on the cost of gas faced by all consumers. This could lead to affordability problems during winter peaks, particularly for those consumers with hybrid systems including optimised heat pump capacity. This is because the smaller size of these consumers' heat pumps, along with the potential impact of cold weather on system performance, means that they may have no choice but to switch to gas to adequately heat their home during parts of the winter peak.

One solution to this affordability problem would be to impose limits on the amount of gas that individual consumers can use. 'Rationing' in the utility sector has precedent – for example hose pipe bans are used in the water sector during times of shortage. However, while it might help in the short term to relieve major pinch points, this type of regulatory solution is unlikely to be efficient in the longer term, as it would reduce the incentive for investment for gas production (or gas import facilities), and therefore lead to higher long term prices for gas. In addition, it could distort consumers' investment decisions, reducing their incentive to move away from gas based systems. We therefore do not include this as part of our market and regulatory models.

Instead, consumers who know they will need to use gas during the winter peak could be encouraged to take out insurance products around the gas price. For example, these could take the form of long term fixed price contracts. We consider these further in our market and regulatory models.

5.1.4 Networks and storage

Pipes are likely to remain the cost-effective transport option for most gas.

There is also a potential role for trucking gas, where AD plants are off-grid. This service operates as a competitive market where pipes are not cost-effective, as explained in Section 5.2 below.

The topography of the network is similar to today, but flows are significantly altered. Rather than flowing gas in from a relatively few high-pressure injection points far from sources of demand, there are a large number of distributed injection points, many of which are at lower pressure and close to sources of demand. This implies the need for network investment in the transition. We consider this further in Section 8.

In the methane transmission and distribution networks, there is some decommissioning and upgrading to allow gas to be pumped from LDZs to NTS. Fixed costs dominate although we assume that these have been largely recovered in the transition through accelerated depreciation.

Methane storage is also similar to current storage facilities, with some decommissioning as the total methane used is lower than today. The requirements for seasonal storage are more challenging to meet.

Figure 15 Methane Peaking: Networks and Storage

Function	Presence in scenario	Characteristics	Links to other elements of the scenario and location requirements
Methane transmission network	Current NTS with some decommissioning.	Fixed costs dominate. Assume that these have been largely recovered in the transition through accelerated depreciation.	
Methane storage	Current storage with some decommissioning.	Mainly seasonal storage. Smaller absolute peak to trough means that some existing storage sites are no longer required.	Needs to link up to methane transmission network.
Methane distribution network	Current distribution network with some decommissioning and upgrades to allow gas to be pumped from LDZs to NTS.	Fixed costs dominate. Assume that these have been largely recovered in the transition through accelerated depreciation.	

Source: Frontier Economics and Aqua Consultants

5.1.5 Scenario commentary

This scenario requires that major developments within the electricity system have occurred, with requirements for additional network and generation capacity to meet heat demand.

The fact that many consumers can switch in the relatively short term between gas and electricity in this scenario suggests that greater coordination across these sectors is required. Options for this coordination are discussed in further detail in Section 8.

We note that the Methane Peaking scenario offers a marked contrast to the High Hydrogen scenario in terms of consumers' experience of the end point. Under this scenario, consumers' end use heating and cooking demand is largely electrified and, as a result, consumers must adapt to the differing characteristics of the associated end use technologies, including their functionality, and the footprint of the technologies in the home.

However, as discussed in Section 8, Methane Peaking could be realised through a far less coordinated transition process than may be needed in the High Hydrogen scenario, owing to the absence of a physical switchover of the network. Instead, the system can be transformed through a series of relatively discrete, incremental and independent changes at all points in the supply chain from production to end-use.

5.2 Model summary and design rationale

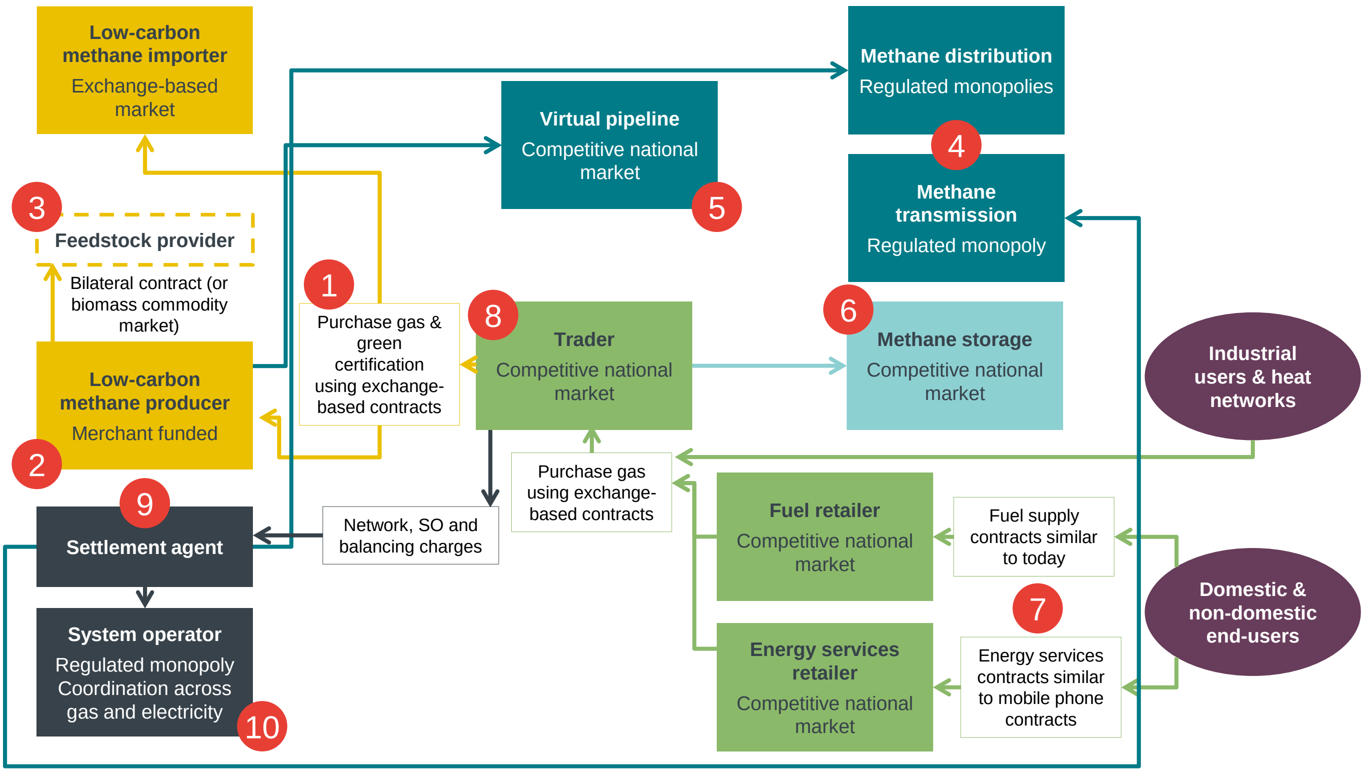
In the market-driven model, government intervention is limited to the management of major market failures. We first summarise this model, and explain the rationale for its design.

We then cover the additional-intervention model, focussing on where this differs from the market-driven model. As described in Section 3, the additional-intervention model is an iteration of the market-driven model, which explores the implications of greater government intervention where this might be beneficial to the functioning of the gas system.

5.2.1 Market driven model

The market models for the Methane Peaking scenario is depicted in Figure 16 below. This shows the types of institutions that exist, how payment flows between them and, where appropriate, the market or regulatory framework in which the institution operates. In the remainder of this section, we provide further detail on the nature of the market and regulatory arrangements that are envisioned and the reasoning why these arrangements are likely to be most appropriate in the context of the scenario. Note that the numbers in the diagrams cross-refer to the relevant explanatory text.

Figure 16 Methane Peaking market-driven model



Source: Frontier Economics

Production and imports

Great Britain's commodity market **(1)** for gas is broadly similar to today's market in the Methane Peaking scenario, as the gas commodity, post-processing, is essentially the same irrespective of whether it has been sourced from a natural gas reservoir or from anaerobic digestion. Gas producers **(2)** sell gas in much the same way as at present, possibly through the use of intermediate aggregators. In general, we expect that smaller AD sites are run by portfolio operators, which have sufficient scale to participate effectively in relatively complicated exchange-based energy markets. Given the large number of producer plants, the relatively low barriers to being a low carbon gas producer, and the presence of imports, the wholesale gas market is competitive.

The market may need to provide more locational-signals to reflect flow congestion, for example through the use of a locational basis differential to the NBP price. This is because of the more complicated flow patterns resulting from greater distribution level injection. However, given the potential use of network charging to provide the relevant signals and the general abundance of network capacity present in this low demand scenario, it is reasonable to assume that commodity market arrangements look broadly similar to those currently in place.

A system to account for the low carbon nature of producers' methane is required For example, low carbon methane could be certified and low carbon gas certificates could be traded in parallel to the gas commodity itself. This would mirror the certification of renewable electricity that currently occurs. Low carbon gas producers would therefore sell both gas and low carbon gas certificates, with some obligation on suppliers to ensure that the gas they supply is suitably accredited.

Feedstock

Upstream of the gas commodity market **(3)**, domestic producers of low carbon methane rely on different supply chains depending on the production technology used. Larger-scale biosyngas producers rely on commoditised biomass inputs like new wood. These may well be traded internationally in a commoditised form. There may, however, be some technologies, like anaerobic digestion, in which plants are far more reliant on locally-sourced inputs, such as wet waste. The transport costs involved mean that any market for such inputs is small in terms of its geographic coverage, and possibly not particularly competitive.

Owners of AD and similar plants seek to secure themselves against the supply chain risk of not having access to inputs. One way to achieve this would be to vertically integrate with upstream suppliers, e.g. wet waste producing activities like farming. However, given the expected complexity of the energy markets we assume that a single company would not operate both in this space, and in the upstream industry. In particular, gas producers are selling into relatively complicated and sophisticated commodity and certificate markets, and may potentially face complex locational charging. Syngas plant owners that are dependent on these localised waste sources may instead be portfolio plant owner / operators that combine expertise in both the gas markets and the supply chain. This mirrors what is already happening in AD today. These portfolio operators seek to secure long-term supply contracts for their inputs. In the absence of these contracts, they have to try and manage the supply chain risk through diversification across the portfolio. The government could usefully step in to try and establish some forums for the localised trading of the relevant inputs, in order to try and drive some efficiencies of supply and some diversification of supply risks.

Gas transport and storage

Where gas is transported through pipelines **(4),** the regulatory model is again relatively similar to today. The role of the networks is the same.

Given the much lower level of network utilisation in this scenario, cost-reflective network charging is based more on capacity than on the volume of throughput.

There may also be a new role for so-called virtual pipelines **(5)**, in which gas is transported by road tanker. Specifically, it may be efficient to produce syngas at sites that are off-grid, close to input suppliers for syngas production. In these cases, the gas produced is sent by road to specialised injection sites, owned by the pipeline networks. The tankers used as part of the ‘pipeline’ are assumed to have lower costs and shorter lifetimes than a typical network investment. They are also inherently mobile. All of these features suggest that there should be a competitive national market in the provision of virtual pipeline services, with no significant barriers to the entry of new providers into the market. Producers could also choose to lease or own their own tankers, effectively integrating this function. Regulatory intervention is really only required to ensure that suitable injection sites are built on the pipeline networks and that a suitable third-party access regime is put in place for this infrastructure.

The storage market **(6)** operates in a manner similar to today, with a competitive market charged based on injections, withdrawals and volumes stored. Changing patterns of demand for storage make the returns to storage more uncertain and alter the relative distribution of pricing, with greater emphasis placed on the volume stored, than whether or not gas is flowed. This helps transfer the risk of a mild winter from storage owners to traders. As we discuss later, there may also be additional government intervention to encourage sufficient stored supplies, although this would not fundamentally alter the way in which the market is transacted.

Retail

The retail gas market **(7)** includes a variety of retail propositions, which co-exist and compete with one another. We distinguish in Figure 16 above between ‘fuel retailers’ and ‘energy services providers’, although a single retailer could provide both services. Fuel retailers would reflect the retail model currently in use, in which end-users are charged based predominantly on the volume of gas used. The energy services providers, by comparison, can take advantage of the greater complexity of domestic energy use decisions to provide a bundle of services, and to act as aggregators of the demand side response provided by their customers. In the context of this scenario, where consumers are using hybrid heat pumps, energy services providers can optimise fuel use across gas and electricity dynamically in order to minimise consumer costs. They may also be using some control over heating technologies to act as an aggregator and sell power market services to national or distribution-level system operators. For example, they may be able to provide localised control of power demand by switching domestic heat loads to use gas.[18] The economic value that the energy services providers unlock by doing this could then be shared with consumers in the form of lower tariffs.

These retailers can also offer support and financing for the installation of equipment. Propositions of this type might be driven by the need to install costly specialised technology in order to provide the energy services discussed above, or it might simply be a response to consumers' desire for financing when switching to potentially costly hybrid heat pump solutions. In these cases, the provider might even retain ownership over part of the in-home installation, a bit like a lease-to-own programme.

As described in Box 4 above, some consumers will have an insufficiently sized heat pump to meet demand across the whole of the winter peak. Consumers with these technologies will have to switch to gas during very cold weather to adequately heat their home. Given the steep supply curve for gas (which implies that the price may rise sharply with demand) there may be demand for retail products which help manage risks around peak gas prices. For example, value propositions may develop in the market that include insurance products or long term fixed price contracts.

We discuss the implications of these issues for government intervention further in the next section. Broadly speaking however, we envisage a competitive retail market, with a variety of retailers offering multiple propositions ranging from simple fuel retail to more extensive energy service contracts.

Trading and operations

The formal job of trading gas falls to the trader function **(8)**, which, like today, is usually integrated into a retail business or with an upstream producer. Traders are responsible for purchasing gas, low carbon certificates and storage and paying for transport, system operation and balancing.

Again a single settlement agent **(9)** is anticipated in order to simplify the payment flows and contractual arrangements.

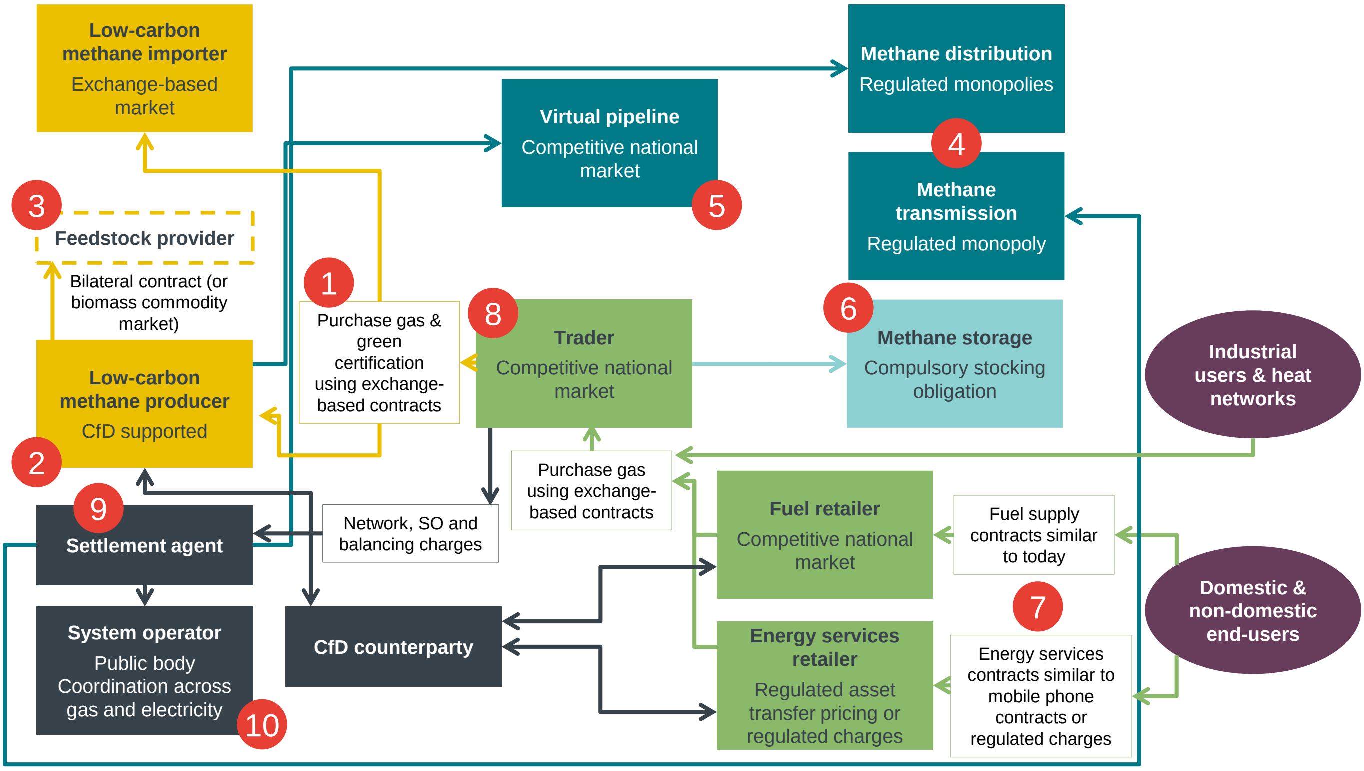
Gas system operation is carried out by a single operator **(10)**. As discussed further in Section 8 on the transition, the more immediate substitutability between gas and electricity in the provision of heat that would occur in this scenario may encourage or require greater coordination in the system operation of gas and electricity.

5.2.2 Additional-intervention model

As described in Section 3, the two market models we have developed for each scenario have similar structures but differ in the extent of government intervention. We now present the additional-intervention model (Figure 17) and describe how this differs to the market-driven model.

[18] In order to provide these services, it may be necessary for consumers to hand over some control to the energy services retailer. Retail propositions could differ with respect to the level of control that the consumer has, for example, whether and to what extent the consumer can override the retailer's fuel choice.

Figure 17 Methane Peaking additional-intervention model



Source: Frontier Economics

The additional intervention model includes the following actions by government.

- **Upstream investment support (2)** – The market-driven model assumes that investors in low carbon methane production can access commercial funding at reasonable cost because, for example, the Government has credibly made fossil fuel commercially uncompetitive. However, there may be policy risk for investors associated with this, even in the steady state. There might be concern, for example, that restrictions on the use of natural gas might not be persistent. In this case, the Government may wish to provide sufficient certainty to production projects that their financing costs become more manageable. In addition, where having domestic production in place is important for security of supply reasons, the Government may also want to intervene to reduce the volume risk faced by producers (up to half of demand could be dependent on weather-driven peak heating demand in this scenario). One means of doing this would be to provide investor support. An example of this would be providing CfDs, which would effectively guarantee the gas price received by producers. Any investment support would ideally be auctioned, to minimise the consumer cost of the support mechanism and make the mechanism easier to remove if, for any reason, it was no longer required. While there are many options for providing upstream investment support, a CfD-type support mechanism could work well in the context of the Methane Peaking scenario because the large number of producers makes a standardised contract format administratively preferable, and the volume-linked payments should help incentivise output. The presence of a relatively liquid and well-established commodity market for gas also provides an obvious reference price. Auctions could also be designed to incentivise the introduction of new, more innovative production technologies by giving preference to specific immature technologies.

- **Intervention to incentivise storage (6)** – The rationale for intervention in this case is essentially identical to that discussed for the High Hydrogen scenario in Section 4. Unlike the High Hydrogen scenario, the transport sector is not expected to be significantly affected by a shortage of supply in this scenario and some heat could still be provided through the use of heat pumps. Consequently, the absolute costs of supply shortage or interruption are lower. A compulsory stocking obligation for retailers would be an example of how this intervention could be made.

- **Regulation of energy services providers (7)** – If energy services providers must invest in the installation of costly, fixed in-home equipment, they need to restrict the customer from leaving them prematurely, before they have recouped this investment. Were this sort of arrangement to be commonplace, it could hamper effective competition by creating barriers to switching and require government intervention. This is not to say that the use of in-home equipment necessitates intervention. There are plenty of existing business models, like those linked to mobile phones or cable TV services with a box receiver, where consumers are tied to providers for a fixed length and must either return equipment and / or face penalty payments if they wish to terminate the contract prematurely.

  However, if the capital costs were significantly larger, or it were significantly more difficult to remove the relevant equipment, as might be the case with the installation of a smart hybrid heat pump system, lock-ins and contract lengths might become more problematic for competition. In these cases, the Government might have to consider regulatory measures. One possibility would be to implement a regulated set of asset transfer prices so that retailers could buy the relevant in-home assets from each other at a reasonable price as part of a customer switch. A similar system already exists for LPG providers with respect to the storage tanks.[19] At the extreme, the Government might conclude that, although energy service provider propositions were useful, they could not be provided competitively and, consequently, that the tariffs charged should be regulated in some way to prevent overcharging.

- **Further intervention on system operation (10)** – The rationale for further intervention on system operation may be even greater than that discussed for the High Hydrogen scenario in Section 4. In this scenario, there is direct on-going trade-off being made between gas and electricity in the provision of heat. Ideally, the system operator needs to have incentives to make sure that this trade-off is judged accurately and does not result in the shifting of costs to the power system operator (if separate) or to the power sector more widely.

[19] These solutions are designed to facilitate switching retailer, but there are other challenges associated with a business model that ends up indebting the household to the retailer. For example, what happens if the occupants move? Different models would be available, For example the original occupant could become liable for termination fees that effectively repay the outstanding equipment cost on sale. Alternatively, the debt could be transferred with the meter to the new owner, and therefore reflected in the sale price of the property.

5.2.3 Comparison to today's models

In the 2050 steady state, market models for Methane Peaking do not look radically different to today's market (Box 5).

BOX 5: COMPARISON OF THE 2050 MODELS WITH TODAY'S

Upstream:

- Gas continues to be competitively exchange-traded. The reconfiguration of the grid may create new impetus for locational pricing and lead to locational basis relative to the exchange-traded NBP price.
- A new, separate market for low carbon certificates is created.
- The upstream market incorporates an abundance of comparatively small-scale producers, relying on multiple production technologies.

Networks and storage:

- Networks face very similar regulation to today.
- Given the much lower level of network utilisation, cost-reflective network charging is based more on capacity than on volume.
- Network charging may also have to adapt to reflect the changing use of the network, with mass distribution-level injection, different flow patterns and links to competitive virtual pipelines.
- Pipeline networks may face direct competition from road-based transport networks, although these are only used in practice where pipeline supplies are not available.
- The storage market works in a similar manner to present, but demand may be underpinned by Government stocking obligations.
- Coordination between gas and electricity system operation is required, with a direct on-going trade-off being made between gas and electricity in the provision of heat. Under the market-driven model, the system operator is a privately-owned regulated monopoly, as it is today. In contrast, under the additional intervention model, there is either increased oversight of the privately owned monopoly, or a move to a publicly-owned system operator.

Downstream:

- Energy services providers compete alongside fuel retailers by offering services linked to the use of flexible hybrid heat pumps, and aggregating the demand side response that hybrid heat pumps can provide. Unlike today, these propositions reflect a sizeable chunk of the total retail market.

5.2.4 Uncertainties

The design of the market models in the steady state described above is driven by a set of assumptions within the scenarios. We now consider the impact on market models of relaxing the most significant of these.

- **Even without a liquid international market for low carbon methane, upstream markets are likely to be competitive.** Around 50% of methane is assumed to come from imports in this scenario**.** While the absence of imports would reduce the availability of low carbon methane for use in this scenario (and increase the level of electrification required), even without imports to set the marginal price, there could still be multiple small producers competing on price.
- **Without access to sustainable sources of feedstock, this scenario is not likely to be feasible.** The Methane Peaking scenario assumes that there is sufficient genuinely sustainable feedstock internationally to enable the production of domestic and imported low carbon methane. Where this feedstock is not available the Methane Peaking scenario would have to rely on greater electrification, or greater use of hydrogen for carbon targets to be met.
- **If consumers wish to use low carbon gas all year round (despite the additional costs this entails) measures to protect vulnerable consumers in the short run may be required.** As described in Box 4, the choice of some consumers to use gas outside the winter peak could push up the price of gas for everybody else, including those that have no choice to use gas to adequately heat their home. The steep supply curve for gas in this scenario means that this problem is more acute than it is in today's market. While insurance products and long term fixed price contracts could offer market-based protection to most consumers, in some cases, it may be necessary to intervene to protect vulnerable consumers from sharp price rises. This could involve for example offering one-off subsidies to manage any short term detrimental impacts.
- **A plentiful supply of imported low cost low carbon methane would reduce the need for insurance or long term fixed price products in the retail market, but could increase the case for domestic investor support**. We have assumed a steep supply curve for low carbon methane. If, instead, increases in demand for gas during cold snaps could be met through low cost imports, the risks to consumers who rely on gas at peak times would be reduced, and the need for insurance type products in the retail market would diminish. If these plentiful imports were cheaper than domestically produced low carbon methane, investor support could be required if the Government wished to have a domestic production capability. Having a domestic production capability may be desirable, depending on policy priorities around security of supply.

6 REGIONAL GAS GRIDS MODELS

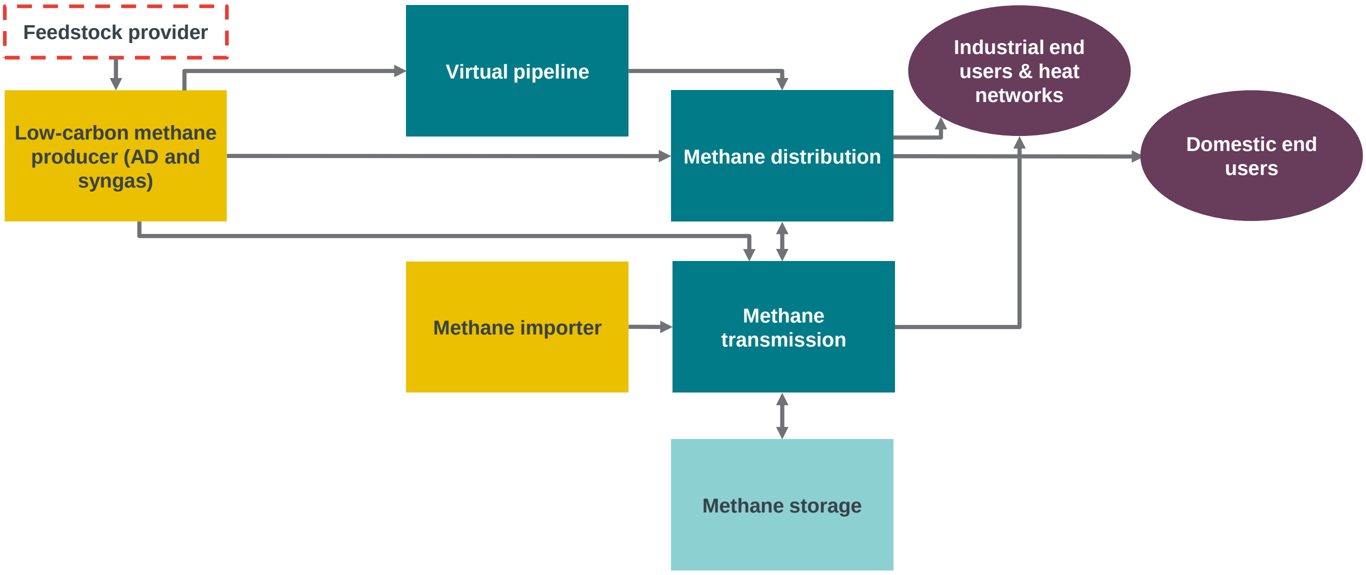
6.1 Attributes of scenario in the steady state

6.1.1 Overview

In the Regional Gas Grids scenario, the gas grid is split into distinct areas of low carbon methane and hydrogen use. Around 70% of demand is met by domestically produced hydrogen from SMRs fed by domestic shale gas, with some small independent methane grids supplied locally by AD and syngas plants.[20] Total electricity production from gas has fallen and has shifted to small-scale distributed CHP and fuel cells. These are used to help avoid electricity distribution reinforcement following the electrification of transport.

The result is a scenario in which gas systems are sub-national and potentially very localised. Methane and hydrogen standards and equipment coexist, segregated spatially based on the topography of their relevant networks. The use of both gasses is driven ultimately by a desire to minimise system costs. Low carbon methane is assumed to be cheaper but insufficiently plentiful to enable national use. Instead its use is limited to those areas where hydrogen conversion is most expensive. This is generally in rural areas where mains replacement has not taken place and therefore network conversion is likely to entail relatively large network replacement works.

Figure 18 Regional Gas Grids: Methane physical flows

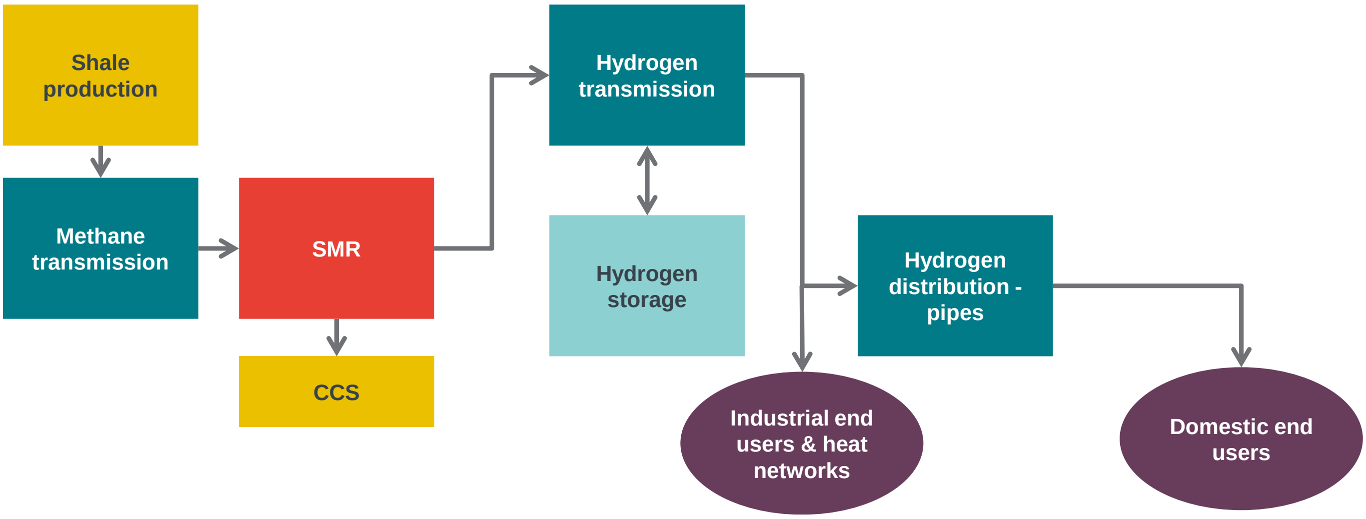


Source: Frontier Economics

Note: These flows are identical to the methane peaking case.

[20] As noted previously, domestic hydrogen production could alternatively be supplied using imported methane and this would not materially change the market and regulatory models developed for the Regional Gas Grids scenario.

Figure 19 Regional Gas Grids: Hydrogen physical flows



Source: Frontier Economics

Box 6 describes the key conditions that would need to be in place for this scenario to be realised.

BOX 6: REGIONAL GAS GRIDS: WHAT DO WE NEED TO BELIEVE?

Commodity markets and prices:

- It is economic to produce hydrogen from fossil methane).
- There is a liquid international market for low carbon methane.
- GB has access to sustainable international sources of feedstock for use in the production of syngas.
- Domestic production of low carbon methane cannot be expanded further without becoming more costly than imported supplies of low carbon methane.

Technology feasibility and cost:

- Hydrogen storage is feasible and sufficiently competitive, relative to increasing SMR capacity, that significant new capacity is built.
- Sustainable CCS is available for SMR facilities.
- Sustainable feedstock available to production of sufficient low carbon methane annually and this is the best use of this feedstock given the potential alternatives available.
- Trailer-based methane storage and transport makes off-grid methane production commercially viable.
- Micro-CHP and fuel cell technologies become sufficiently small, cheap and flexible that they are deployed in a range of commercial and domestic environments where there is a system benefit associated with distribution-level power generation.

Consumer preferences:

- The public accept potentially significant differences in the vector fuels available across regions.
- Consumers continue to prefer gas-based heating technologies to electrification where they have access to a gas grid.

We now describe the assumptions that drive the market structure covering:

- upstream drivers;
- demand drivers; and
- networks and storage.

The gas system market models that result from these assumptions are described in Section 5.2 below.

6.1.2 Upstream drivers

Low carbon methane is produced domestically through AD and syngas plants, and imported through LNG import terminals from a liquid international market. For the hydrogen sections of the gas grid, production takes place through domestic SMR plants. These are fed by a newly constructed dedicated shale gas pipeline network.

Figure 20 gives the details of the upstream production elements.

Figure 20 Regional Gas Grids: Upstream drivers

Technology or infrastructure	Presence in scenario	Characteristics	Links to other elements of the scenario and location requirements
Anaerobic digestion plant	250 AD plants producing around ≈30 TWh of methane.	Capital-intensive plants processing local wet waste (farm waste, food waste or sewage sludge). Most economically efficient to run baseload, but output can be varied with demand.	Wet waste source is likely to drive location. Needs to link up to methane T or D network, or to a virtual pipeline. Competes with syngas plants and imports.
Syngas plant	165 syngas plants producing ≈100 TWh of methane.	Capital-intensive plants processing waste or bio-feedstock. Bio-feedstock comes from liquid national and international markets (unlike AD). Most economically efficient to run baseload, but output can be varied with demand.	Needs to link up to methane distribution or transmission network, or to a virtual pipeline. Competes with AD plants and imports.
LNG import terminals	Exiting LNG import terminals continue to be used – importing around 65 TWh of low carbon methane.	Liquid international market. Marginal source of gas in this scenario (generally more costly than domestic production).	Needs to link up to methane T or D network, or to a virtual pipeline. Competes with domestic production.
SMR plant	Around 70 SMR facilities, each consisting of multiple reformers, with total annual output of around 455 TWh.	Capital-intensive construction. Input methane is significant running cost.	Requires links to methane transmission, hydrogen transmission and CCS networks. CCS networks are likely to determine location and imply clustering of facilities.
Shale infrastructure	7,000 to 10,000 individual shale wells with	Newly built gas gathering pipeline network and processing infrastructure	Requires links to SMR plants via pipelines

Source: Aqua Consultants and Frontier Economics

Anaerobic digestion plant

As in the Methane Peaking scenario, capital-intensive AD plants process local wet waste such as farm waste, food waste, or sewage sludge. It is most economically efficient to run at baseload, but output can be varied with demand.

The location of the wet waste source drives the location of the plants. These are either linked directly to a pipeline network or else truck their production by road for injection into the grid. The methane produced by AD competes with syngas and imports.

The scale of methane production from AD plants is the same as in the methane peaking scenario.

Syngas plant

Again, as in the Methane Peaking scenario, capital-intensive plants process waste or bio-feedstock which comes from liquid national and international markets. This differs from the AD feedstock, which is supplied locally. It is most economically efficient to run at baseload, but output can be varied with demand.

The plants must be connected to the methane distribution or transmission network, or to a virtual pipeline. Syngas plants compete with AD plants and imports.

LNG import terminals

LNG is imported from a liquid international market, and is assumed to be generally more costly than domestic production due to liquefaction / re-gasification cost and shipping costs (otherwise domestic production would go out of business). The terminals are connected to the methane distribution or transmission network, or virtual pipeline. Imports compete with domestic methane production.

SMR plant

There are material upfront construction costs associated with domestic SMR plants. The plants require links to methane transmission, hydrogen transmission, and CCS networks[21]. Because of this, CCS networks are likely to determine the location of the SMR plants and imply the clustering of facilities.

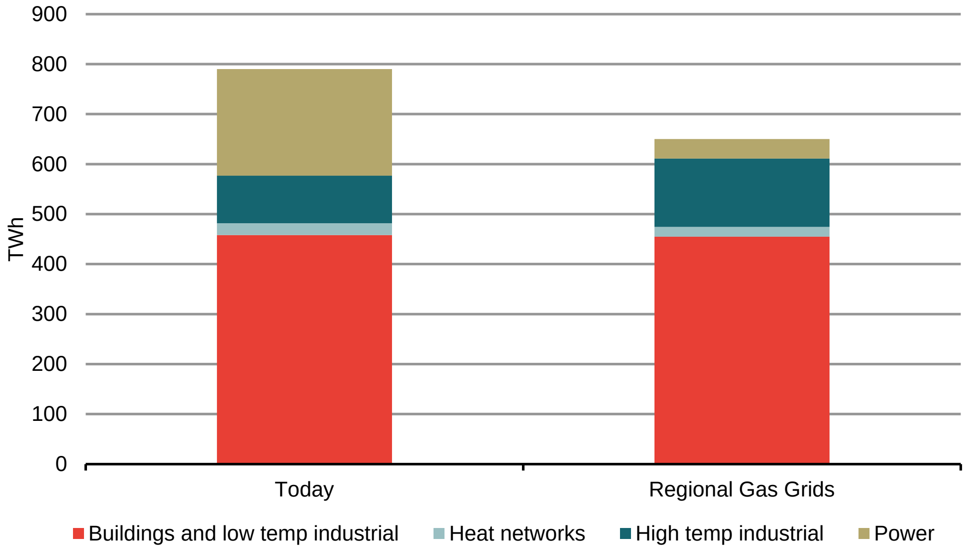
Input methane is a large input cost to the production of hydrogen.

6.1.3 Demand drivers

Total demand is 455 TWh of hydrogen and 195 TWh of methane, compared with 790 TWh of methane today (Figure 21). Improved insulation diminishes the absolute peak to trough variation, although this variation remains broadly similar to today. Relative seasonal peakiness may appear greater due to the lower baseload gas demand from power generation. The gas that continues to be used for power generation tends to be used by distributed generators.

[21] The requirements for CCS are out of scope for this project. However, we note that there are significant challenges around long term storage liabilities associated with CCS.

Figure 21 Regional Gas Grids: Gas demand



Source: Frontier Economics

Figure 22 provides more detail on the demand characteristics.

Figure 22 Regional Gas Grids: demand characteristics

Function	Quantity (proportion of total demand)	End use technology	Consumer choice	Predictability	Demand profile (peakiness)
Total demand	455 TWh of hydrogen and 195 TWh of methane (compared with 790 TWh of methane today).		Most consumers have access to either methane or hydrogen and prefer to use this for heating instead of electricity. A few large consumers/ heat networks may be set up to use either gas.		Absolute peak to trough is be broadly similar to today, diminished by improved insulation. Relative seasonal peakiness may appear larger due to reduced/changed role of gas in power generation (where it provides distributed energy).
Demand from buildings and low-temperature industrial demand	70% (compared with 58% today).	Methane and hydrogen boilers (which are similar to current heating technology), micro-CHP and fuel cells.	Customers can switch to electric heating, but face little incentive to do so.	Demand remains weather dependent, as today. Greater capacity to generate distributed power means gas demand is linked to power prices.	Building demand is seasonal owing to space heating requirements. Improvements in insulation and a greater need for cooling reduces the absolute size of the peak.
Demand from heat networks	3% (compared with 3% today).	Methane and hydrogen boilers, micro-CHP and fuel cells.	Small subset of consumers can switch between gases. Little incentive to switch to electricity.	As above.	Similar to demand from buildings above. Demand profile is likely to be more strongly linked to need to generate power, as heat networks makes more extensive use of CHP and fuel cells than the average home given their greater propensity to make effective use of co-generated heat.
High-temperature Industrial demand	Around 21% (compared with 12% today).		Small subset of consumers can switch between gases.	Industrial customers remain relatively risky – large customers with a chance of going out of business or moving.	Baseload source of demand all year round.

Function	Quantity (proportion of total demand)	End use technology	Consumer choice	Predictability	Demand profile (peakiness)
Demand from the power sector	6% (compared with 27% today).	Micro-CHP and fuel cells.	No relevant fuel switching. 'Power sector' in this case is affected by local heat demand given cogeneration.	Demand varies both due to power prices, but also local network issues – may be predictable in aggregate.	Linked to spikes in net power demand after accounting for non-dispatchable renewable generation.

Source: Frontier Economics and Aqua Consultants

Buildings and low-temperature industrial gas demand

Building demand is met by methane and hydrogen boilers, micro-CHP, and fuel cells. Heat networks meet a small amount of residential heating. Demand is seasonal owing to space heating requirements. Improvements in insulation and a greater need for summer cooling reduce the differentials between high and low demand.

Increased distributed generation capacity means gas demand is linked to power prices.

Heat networks make more extensive use of CHP and fuel cells than the average home, given their greater propensity to make effective use of co-generated heat. This means their demand profile is likely to be more strongly linked to the need to generate power.

High-temperature industrial gas demand

High-temperature industrial demand is a baseload source of demand throughout the year. Industrial customers remain relatively risky as customers since they represent large blocks of demand and may go out of business or move.

Some existing coke, coal and methane burning industrial processes are converted to use hydrogen and methane.

Power sector gas demand

The demand profile for gas used in electricity generation is linked to spikes in net power demand after accounting for non-dispatchable renewable generation[22] . Demand varies both due to overall power prices and in response to the need for distributed generation to relieve electricity distribution network congestion. Although the latter form of demand is driven by localised network issues, the aggregate impact on gas demand may be predictable if, for example, these network issues coincide with the charging patterns of electric vehicles.

[22] This is consistent with a generation mix dominated by inflexible or intermittent low carbon plants. If the generation mix is more flexible (because of a greater penetration of more flexible low carbon plant such as gas CCS or biomass), or if there is significant flexibility on the demand side, less hydrogen may be required for peaking generation.

6.1.4 Networks and storage

In the Regional Gas Grids scenario, parts of the current distribution network are converted to hydrogen. In some areas pipes may not be cost-effective, for example where methane producers are not close to the methane grid. For these cases a fleet of lorries serving as a ‘virtual pipeline’ may help to supply islanded methane networks.

Figure 23 Regional Gas Grids: network and storage drivers

Technology or infrastructure	Presence in scenario	Characteristics	Links to other elements of the scenario and location requirements
Methane transmission network	Current NTS with some decommissioning.	Fixed costs dominate. These have been largely recovered in the transition through accelerated depreciation.	NTS interconnects some methane grids, but now mainly used to feed SMR with shale production.
Methane storage	Some existing storage but also smaller scale storage on micro-grids and linked to AD sites.	Mainly seasonal storage. Much existing methane storage is converted for hydrogen. Reduced interconnection (micro-grids, off-grid AD) creates new types of demand.	Needs to link up to methane distribution or transmission network, or to a virtual pipeline.
Methane distribution network	Current distribution networks which aren’t converted. Some upgrades to allow gas to be pumped from LDZs to NTS.	Fixed costs dominate. These have been largely recovered in the transition through accelerated depreciation.	
Virtual pipeline	National network of road transport.	Relatively small capital cost of specialised vehicles.	Connects off-grid AD producers and provides emergency supplies to islanded methane grids.
Hydrogen transmission system	New hydrogen NTS, but smaller than in high hydrogen system.		Interconnects SMR plants and converted distribution networks.
Hydrogen distribution system	Converted existing distribution grids	Fixed up-front costs need to be reimbursed. Comparatively small opex costs.	

Source: Frontier Economics and Aqua Consultants

Methane grid

As in the Methane Peaking scenario, the current NTS and distribution networks are used for transmission and distribution, with some decommissioning to reflect the lower methane demand compared to today. Again, fixed costs dominate the networks, with most assumed to have been recovered during the transition period.

Methane storage is mainly seasonal. The reduced interconnection of the network created by the separation of hydrogen and methane areas creates new types of storage demand. Smaller scale storage is linked to off-grid AD production sites, and to isolated methane grids. Localised pressurised containers, co-located with production facilities, are used in addition to small scale LNG facilities. This storage is connected to the transmission and distribution network either through pipes or a virtual pipeline.

Hydrogen grid

Existing distribution networks have been converted to hydrogen and connected to SMR plants by a new hydrogen NTS. This hydrogen distribution network is characterised by fixed up-front costs, but comparatively low opex costs.

Storage for hydrogen is a mixture of shallow and deep salt cavity storage and depleted hydrocarbon fields to meet intraday and inter-seasonal demand profiles.

6.1.5 Scenario commentary

The Regional Gas Grid scenario may ensue where there are major differences in the costs, or technical feasibility, of low carbon gas options across regions, driven by differences in local characteristics. Alternatively, it may result from path dependency. For example, a patchwork of different solutions across GB could result if it was necessarily in the transition to extensively roll-out both hydrogen and low carbon methane systems before their costs and benefits could be understood.

Either way, the resulting scenario combines many elements of the High Hydrogen and Methane Peaking scenarios. The key difference relates to the regional disparities in technology choice for consumers. In turn this may also result in disparities in cost, either in aggregate, or between upfront costs of technologies and their ongoing running costs. Unlike in the other scenarios, where regional disparities may be a feature of the transition (Section 8) these regional differences could persist in steady state.

6.2 Model summary and design rationale

Having described the Regional Gas Grid scenario, we now focus on the market and regulatory models that could operate with this scenario.

This section is split between discussions of the low carbon methane system, the hydrogen system, and the system for islanded micro-grids. We begin by summarising the market-driven model for each of these systems, in which government intervention is limited to the management of major market failures.

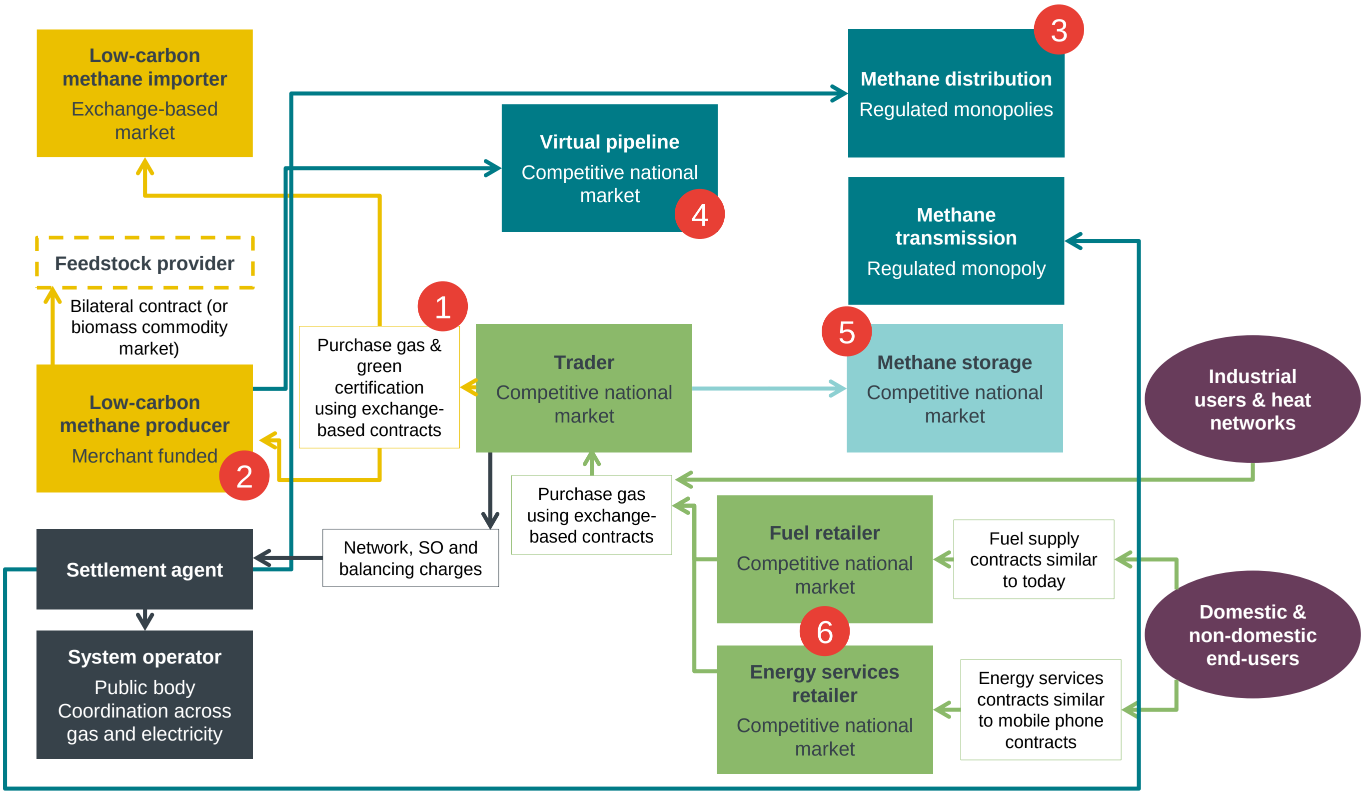
In Section 6.2.3, we cover the additional-intervention models for the hydrogen and methane systems, focussing on where these differ from the market-driven models..

6.2.1 Market driven model

We now consider market models for the low carbon methane and hydrogen markets within the Regional Gas Grids scenario.

Low carbon methane model

Figure 24 Regional Gas Grids market-driven model for low carbon methane



Source: *Frontier Economics*

The models relevant to the low carbon methane network are similar to those for the Methane Peaking scenario. A more complete discussion of the reasoning behind these arrangements can be found in Section 5.2, where we discuss the Methane Peaking arrangements in detail. Here we briefly recap the arrangements and highlight some differences relative to the Methane Peaking scenario.

Methane in this scenario is traded on a commodity market in much the same way that it is today **(1)**. There is a parallel market for the trade of low carbon certificates. These are given to low carbon producers commensurate with their output. The value of these certificates reflects the additional value of low carbon gas over and above natural gas. Both markets are competitive commodity markets supplied by a large number of producers **(2)**. These producers are frequently portfolio owner-operators, controlling several production facilities. This helps them to hedge their exposure to supply chain problems and to leverage their expertise.

Production facilities either inject gas directly into the pipeline network **(3)**, or truck the gas to dedicated injection sites through so-called virtual pipelines **(4)**. The virtual pipeline network, which was competitive under the Methane Peaking scenario, is even larger in this scenario – more production sites are located off of the methane grid owing to the conversion of much of the distribution network to hydrogen. This increase in size increases the likelihood that the market is competitive.

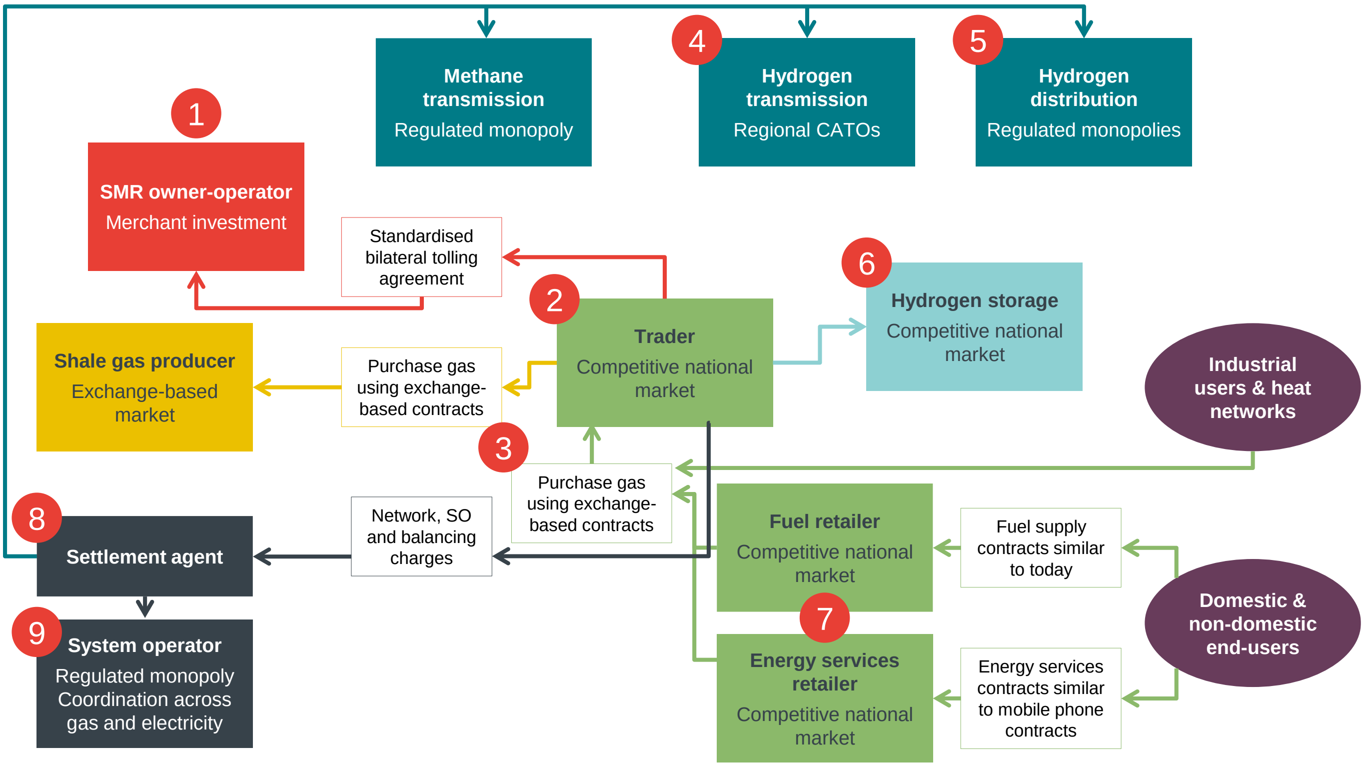
The pipeline networks carry out a very similar function to today and operate as regulated monopolies. On storage **(5)**, although the reconfiguration of the methane network may result in some sites being decommissioned, the number of sites remaining is expected to be sufficient to allow for a competitive market for storage, at least on the non-islanded parts of the methane grid.[23]

The retail market **(6)** includes a variety of retail propositions, which co-exist and compete with one another. As in Methane Peaking, new energy services propositions are developed under this scenario, but these are based on a different set of end use technologies. Specifically, this scenario sees a bigger role for distributed power generation in the form of micro-CHP (and fuel cells, as discussed in the hydrogen model below). As in the Methane Peaking scenario retailers seek to offer propositions that incentivise fuel switching to use these technologies efficiently. This would require relatively granular time of use tariff signals. Retailers may also combine these propositions with financing support, given the relatively high upfront costs associated with micro-CHP. Overall, the retail market is competitive and includes a variety of propositions ranging from simple fuel retail to more extensive energy service contracts.

[23] If, however, storage were to be provided by only a very small number of sites, for example owing to the geology of the sites, competition may be insufficient to ensure an efficient outcome and regulatory intervention may be desirable.

Hydrogen model

Figure 25 Regional Gas Grids market-driven model for hydrogen



Source: Frontier Economics

Production

The production of hydrogen in this scenario is based exclusively around the domestic production of hydrogen using SMR **(1)**. As in the High Hydrogen scenario, these plants are assumed to operate tolling agreements with traders **(2)**. This arrangement isolates the plants' investors from the risks associated with trading the underlying commodities, risks that they are not particularly well placed to manage. These plants are sufficiently numerous (≈70 plants) to allow for effective competition between them. They are financed through purely merchant means on the assumption that, in the steady state, investors can see a track record of well-established and reasonably predictable market behaviour.

Both the wholesale hydrogen and methane markets are competitive, exchange-based, commodities markets **(3)**. This reflects both the possibility for multiple traders to coexist in the market and the homogenous nature of the goods themselves.

Gas transport and storage

Hydrogen transport looks broadly similar to the arrangements in the High Hydrogen scenario, although there is no role in this scenario for the use of virtual pipelines for hydrogen, since transport is electrified and there is no network of hydrogen filling stations. As in High Hydrogen scenario, the transmission network **(4)** is a series of regulated CATOs. The distribution networks **(5)** are expected to be regulated monopolies. This reflects both the very similar functions these bodies provide to present-day networks, despite the change in the gas used, and the fact that, as natural monopoly assets, they cannot be completely deregulated.

It is worth noting that the conditions that made the deregulation of the methane transmission network seem conceivable in the High Hydrogen scenarios do not hold here. Specifically, SMR plants face no import competition that might act to restrain an unregulated network owner and the methane transmission network in this scenario is used to serve end-user consumers of methane, not SMR plants.

The hydrogen storage market **(6)** operates just like the methane storage market, as a competitive market charged based on injections, withdrawals and volumes stored. This reflects both the cost structures of the storage operation and the presence of a sufficient number of storage sites to foster competition.

Retail

Just as with the methane market described above, there are a variety of propositions ranging from simple fuel retail to more extensive energy service contracts **(7)**. The latter seeks to unlock value by using end-use technologies like hydrogen fuel cells to best effect.

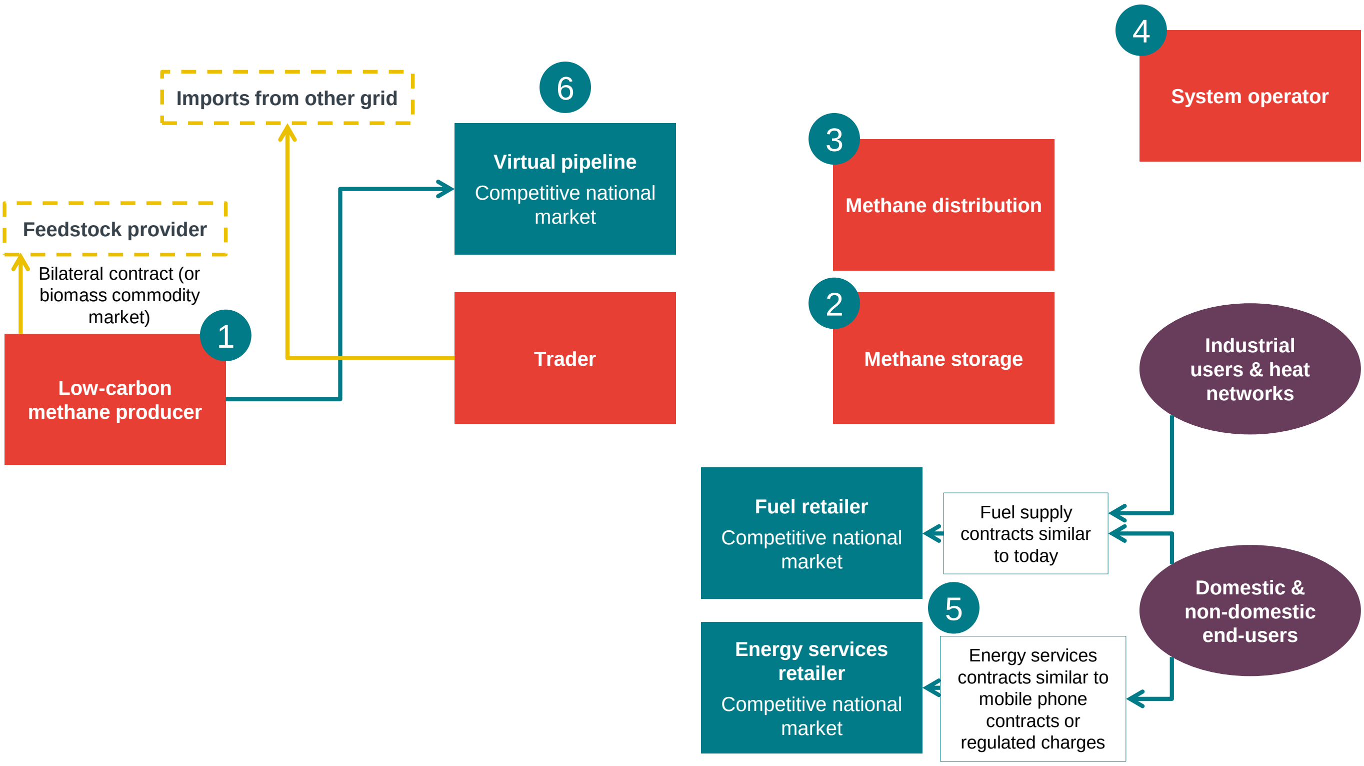
Trading and operations

As with the High Hydrogen scenario, traders play an important role in both of these models, given the use of tolling arrangements for hydrogen production. Some physical traders may take title to the methane or hydrogen right across the supply chain and organise the conversion of methane to hydrogen, though the establishment of the tolling arrangements. Traders also arrange for the storage of both gasses as needed and pay for transport, system operation and balancing. In practice, this function may well be integrated with a retailer, although independent traders, or traders linked to shale production may also exist to try and capture some of the value associated with providing this function.

As for all the models, a settlement agent **(8)** exists to help simplify the payment and contractual arrangements between the many parties involved. A system operator **(9)** is also required to manage real-time operations, and may well span both gases, given the similar skillset involved.

6.2.2 Islanded micro-grid model

Figure 26 Regional Gas Grids model for islanded micro-grids



Source: Frontier Economics

The islanded micro-grids are so small in scale that there are unlikely to be a sufficient number of independent producers **(1)** on them to enable effective upstream competition. The same is also true of storage **(2)**. Although the scope to import from elsewhere using a virtual pipeline provides an upper limit on the amount that producers or storage providers can charge, it is unlikely to provide sufficient protection to secure against the abuse of market power.

Given that the network **(3)** and system operation **(4)** functions must be set up as local monopolies in any event, we assume that a single integrated monopoly gas provider emerges to cover all elements of supply other than retail, bringing together all of the uncompetitive elements of the system in a single organisation.

One reason to favour this approach is the control that it gives to the system operator, which effectively owns all elements of the system. Shocks to supply and demand are likely to be larger in relative terms on a smaller network and the security of supply risks to consumers is significantly larger. Faced with these issues, it seems appropriate to opt for a model that maximises the tools available to the system operator.

Retail **(5)** remains competitive and, as is the case elsewhere, involves both fuel and energy services propositions. Given the additional operational challenges facing a micro-grid, energy services propositions may be even more valuable in this context where they allow for the provision of network management services.

The virtual pipeline services **(6)** used by the network are also competitively provided, since these are a part of the wider national market for this service and therefore benefit from the competitive pressure of numerous providers.

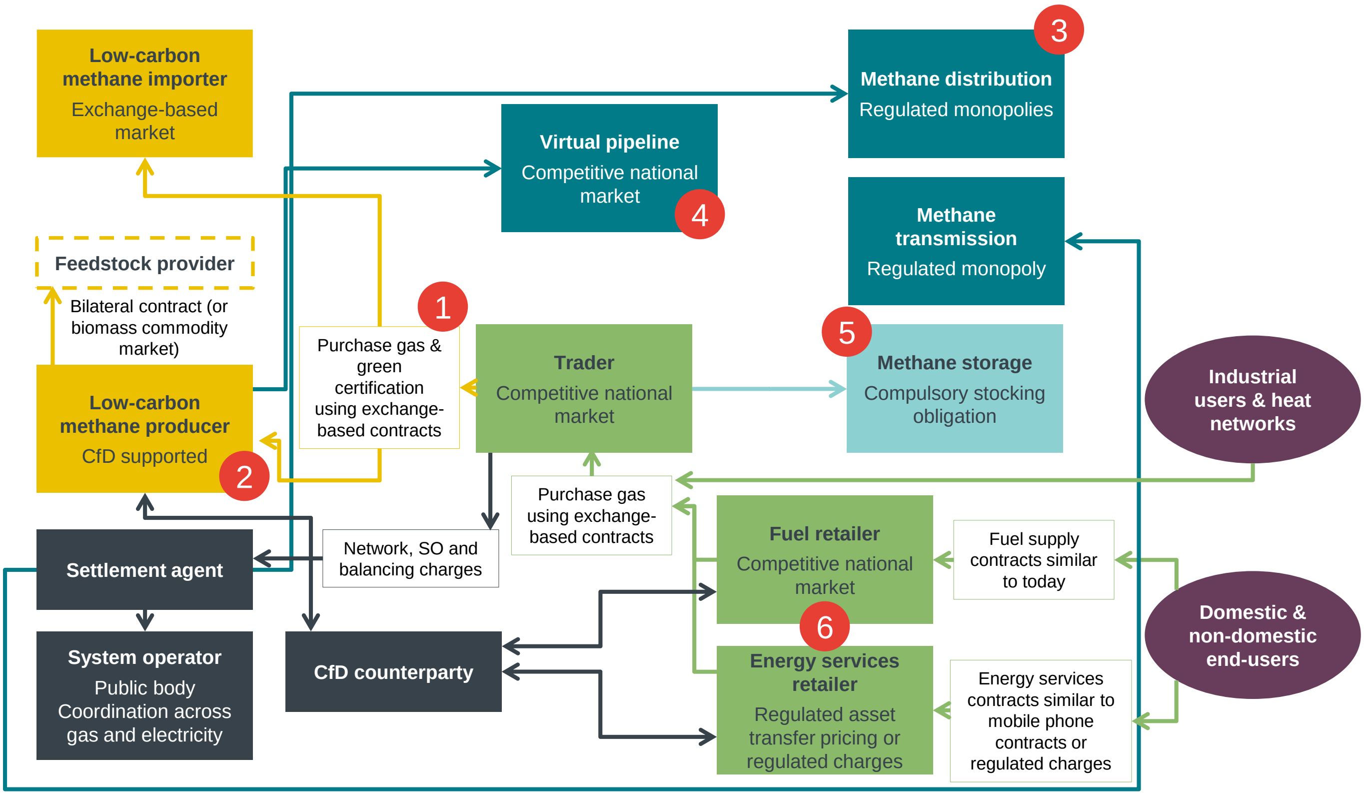
To control the significant power the monopoly provider has, this role could be carried out by a dedicated public body, possibly owned by the relevant local authorities. It is essential that the model does not create a body that is motivated to use its power to exploit its customers and that this body is accountable to its customers for the service that it provides.

Since this model lacks the prerequisites for effective competition, we do not consider the scope for an alternative market and regulatory model.

6.2.3 Additional-intervention models

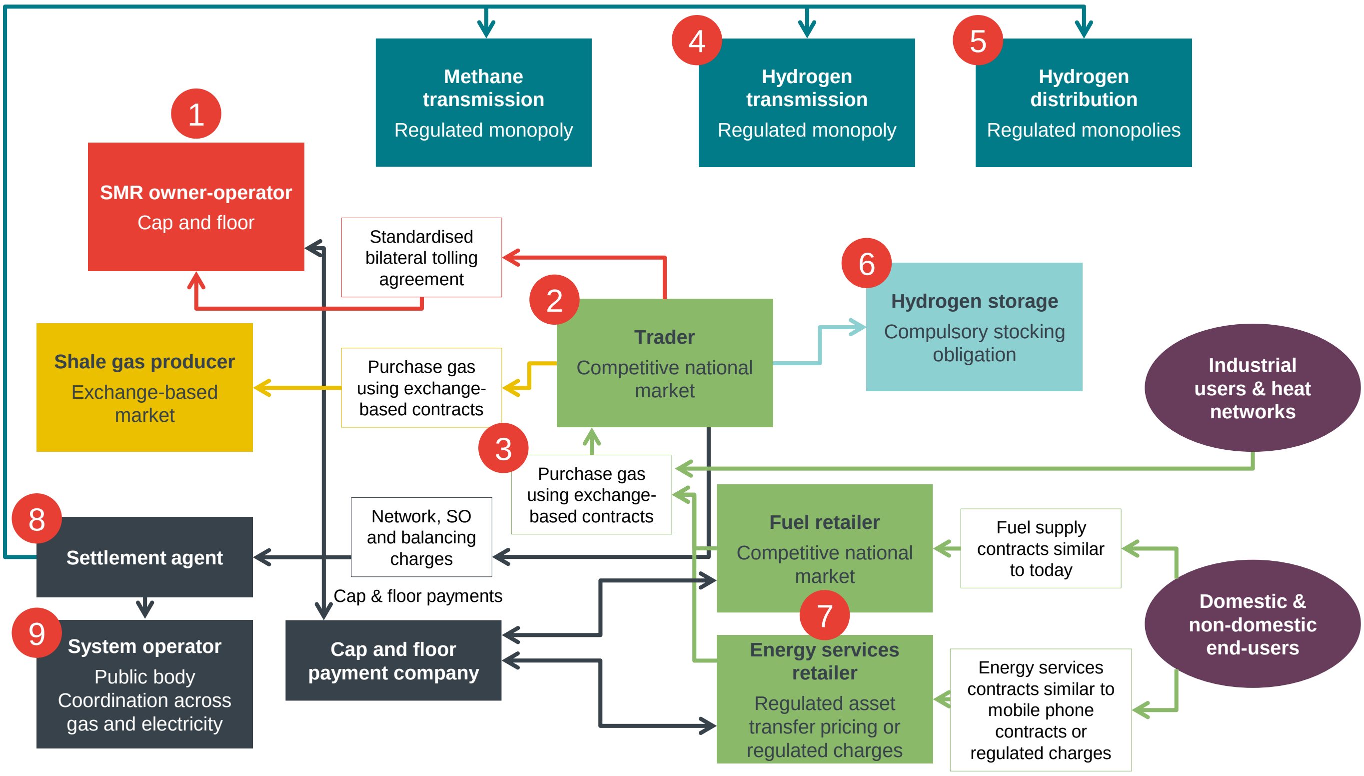
As described in Section 3, the two market models we have developed for each scenario have similar structures but differ in the extent of government intervention. Figure 27-Figure 28 below show the relevant additional-intervention models for the methane and hydrogen systems under the Regional Gas Grids scenario. In this case, the methane model is identical to that under the Methane Peaking scenario.

Figure 27 Regional Gas Grids additional-intervention model for low carbon methane



Source: Frontier Economics

Figure 28 Regional Gas Grids additional-intervention model for hydrogen



Source: Frontier Economics

The market-driven and additional-intervention models differ with respect to the interventions listed below. These differences have all been previously discussed in Sections 4-5 in relation to the High Hydrogen and Methane Peaking scenarios respectively. We therefore limit the discussion here to a brief reminder of the issue and, where relevant, to points that are specific to the Regional Gas Grids scenario.

- **Upstream investment support for hydrogen** – As in the High Hydrogen Scenario, the additional-intervention model bounds investors' potential revenues through investment support. For example, a cap and floor regime could be used to potentially reduce the financing costs of these projects, while transferring some risk to consumers or taxpayers. It is worth noting that the risks faced by SMR investors in this scenario are different from the High Hydrogen case, since they do not now compete directly with imports and electrolysis in the hydrogen market.

- **Upstream investment support for low carbon methane** – As in the Methane Peaking Scenario, the additional-intervention model offers further support to producers. For example, CfD support could be used to reduce investors' financing costs, while transferring some risk to consumers or taxpayers.

- **A single monopoly for the hydrogen transmission network** – As in the High Hydrogen Scenario, the hydrogen transmission system may have been built using a series of regional tenders. Where this is the case, it may make sense to preserve multiple distinct Transmission Owners within the same network. Alternatively, as in the additional-intervention model, the network could be owned and operated by a single regulated monopoly, as is the case with the NTS.

- **Incentives to investment in storage** – The Government could choose to stimulate additional stockpiling of gas, thereby enhancing security of supply at a cost to consumers. For example, the Government could impose a compulsory stocking obligation either low carbon methane or hydrogen, or on both.
- **Regulation of energy services providers** – Where energy services providers develop propositions that rely on a degree of customer lock-in, there may be value in additional government intervention that either facilitates switching for customers who are locked-in, or else protects them from excessive prices. In this scenario, the main technological driver of the new proposition development is the use of fuel cells or micro-CHP to provide distributed generation. A degree of lock-in may be required where suppliers are funding the installation of this equipment, or else providing related equipment designed to allow for the more effective use of the underlying heat and power system.
- **Further intervention on system operation** – The rationale for intervention in this case may be even greater than that discussed for the High Hydrogen scenario in Section 4. Planning a system that relies on the simultaneous use of both low carbon methane and hydrogen, and where islanded micro-grids exist, is likely to be especially challenging. Depending on the precise remit of the system operator(s) overseeing these markets, establishing efficient regulatory incentives may be more difficult and hence the attractiveness of further oversight, or a move to a publicly-owned body may increase.

6.2.4 Comparison to today's models

Once again, in the 2050 steady state, market models for Regional Gas Grids do not look radically different to today's market (Box 7).

BOX 7: COMPARISON OF THE 2050 MODELS AND TODAY'S MARKET MODEL

Upstream:

- Gas continues to be competitively exchange-traded. New exchanges exist for both low carbon certificates and hydrogen.
- The hydrogen supply chain is completely domestic, with few links to international markets. By comparison, the methane supply chain is heavily reliant on imported gas and feedstock.
- Both upstream markets are marked by and abundance of smaller-scale producers and sellers relative to the upstream market today.

Networks and storage:

- The subdivision of the national networks means there are multiple networks and operators.
- Networks continue to face revenue regulation, but there is scope for greater benchmarking across different network owners.
- The storage market works in a similar manner to present, but demand may be underpinned by Government stocking obligations.
- System operation increases in complexity, with a potential requirement to coordinate across the low carbon methane, hydrogen and electricity systems. Under the market-driven model, the system operator(s) are privately-owned regulated monopolies, as today. In contrast, under the additional intervention model, there is either increased oversight of the privately owned monopoly, or a move to a publicly-owned system operator.

Downstream:

- Energy services providers compete alongside fuel retailers by offering services linked to the use of distributed generation technologies (including aggregation of the flexible response that these technologies can provide). Unlike today, these propositions reflect a sizeable chunk of the total retail market.
- The diversity of networks and technologies mean that there may be marked disparities in heating costs across the country.

6.2.5 Uncertainties

Once again, it is useful to consider the impact on market models of relaxing the most significant scenario assumptions. Similar conclusions can be drawn from the discussion in the High Hydrogen and Methane Peaking scenarios for the elements of the scenarios that are common. We therefore focus here on the key element of difference between Regional Gas Grids and the High Hydrogen and Methane Peaking scenarios: the persistent regional disparity in vector fuel choice.

The market models described above are based on the assumption that persistent regional differences in vector fuels and end use technologies are largely accepted by consumers. These differences are generally accepted today, where consumers off the gas grid typically pay more (for example, for electric or oil-fired heating). To the extent that the public does not accept regional differences in the future, the market and regulatory models may need to be adjusted. For example, if the issue was one of more expensive technologies or vector fuels in particular areas, persistent redistribution of costs to ensure “fairness” to those customers could be required. However, such ongoing redistribution could have negative consequences for efficiency, by reducing the cost reflectivity of price signals and facilitating internal migration to areas that are more expensive to serve with low carbon gas.

7 MODEL INSIGHTS AND APPRAISAL

In this section we highlight some of the overarching insights from the model development work and appraise the models themselves.

7.1 Insights from the model development work

The overarching conclusion from the model development work is that none of the scenarios implies a radical reinvention of the market and regulatory structures currently in place. While significant regulatory changes may be required, for example to facilitate greater coordination between energy vectors, many aspects of the market and regulatory framework could remain similar to those in place today. Despite the sometimes far-reaching technological changes required during the transition to realise the scenarios (discussed in Section 8 below), the gas supply chain in 2050 is, with respect to its fundamental features, similar to today. Consequently, even when taking market design decisions on the basis of first principles, we frequently derive solutions that are broadly similar to the arrangements used now.

7.1.1 High level insights

Upstream production could be built around a competitive commodity market

In upstream production, our scenarios imply a situation in which there are many production facilities, with each of them small, relative to overall demand, producing a homogenous and easily commoditised product (Figure 29).

Figure 29 Drivers of upstream competition

High Hydrogen	Methane Peaking	Regional Gas Grids
Domestic production consisting of around 80 SMR and more than 10 electrolysis plants alongside competition from a liquid import market.	Domestic production consisting of around 250 AD plants and around 165 syngas plants alongside competition from a liquid import market.	For methane, domestic production from around 250 AD plants and 165 syngas plants competes with imports. For hydrogen, around 70 SMR plants compete in the market.

Source: Frontier Economics

The capital required for these facilities is, if anything, smaller than we see for natural gas production today, potentially reducing the barriers to entry for gas production. In those scenarios where imports are used, they are assumed to come from liquid, competitive international markets and to set the marginal price, providing both a source of competition and a limit on the ability of any domestic producer to manipulate prices. In these conditions, we would expect there to be multiple producers competing with one another. A competitive commodity market, much like the one that presently exists, would seem the most likely outcome.

Pipeline gas networks could be regulated natural monopolies

In the 2050 steady state, the role for the pipeline networks remains largely the same – to own and operate natural monopoly network assets that transport gas from place to place. Because these assets are natural monopolies, they require a degree of regulation to ensure that they are efficiently used (Figure 30).

Figure 30 Drivers of network regulation

High Hydrogen	Methane Peaking	Regional Gas Grids
Generally, networks remain a natural monopoly, with fixed costs dominating. However, elastic demand from SMR plants means that there is a limit on the price that the methane transmission network can charge. In this part of the network, some deregulation may be possible.	Networks remain a natural monopoly, with fixed costs dominating.	

Source: Frontier Economics

Though many changes to the detailed codes may be required throughout the transition, at a high level, regulatory arrangements similar to those currently in use should be able to incentivise efficient network use and bring forward any necessary investment, enabling the networks to efficiently carry out the functions required of them under all of the scenarios.

There are, however, some notable differences from today (Figure 31).

Figure 31 Drivers of differences in network models relative to today

High Hydrogen	Methane Peaking	Regional Gas Grids
Some hydrogen filling stations (for transport) may be off grid. Road transport of hydrogen could supply these.	Feedstock sources determine the location of gas production plants. Off grid transport of gas and an expanded gas system operator role may be required.	

Source: Frontier Economics

All the scenarios envision the potential transport of gas by road. In the Methane Peaking and Regional Gas Grid scenarios, this is to accommodate distributed gas production close to off-grid sources of feedstock. In the High Hydrogen scenario, this is to supply off-grid hydrogen filling stations. However, the presence of this road-based network is not likely to fundamentally alter the need or nature of network regulation for the pipeline networks.

The scenarios also suggest the possible need for an expanded system operator role for the distribution networks, particularly where they must deal with significant levels of injection onto their networks. These injections imply that gas flows, which are presently top-down from the high-pressure transmission system, potentially become bidirectional, with operators actively managing changing pressures on different parts of the system. The scenario also implies the need for distribution networks to ‘connect’ to the virtual pipelines, through the operation of dedicated injection sites for this purpose. Again however, it should be possible to effectively handle any necessary changes within a regulated monopoly framework.

Storage should be able to operate competitively, although some intervention may be desirable for security of supply reasons

Overall, the role of gas storage in 2050 is effectively the same as today. Although the precise profile of storage changes, according to the flexibility of imports, domestic production and demand, the fundamental service and its provision remains the same. There are multiple providers of a similarly capital-intensive service and it should be possible for this service to be competitively traded among market participants (Figure 32).

Figure 32 Drivers of competition in the storage market

High Hydrogen	Methane Peaking	Regional Gas Grids
Multiple providers of storage compete. Competition also comes from alternative providers of peak supply, such as gas producers.		

Source: Frontier Economics

The only potentially significant driver of additional intervention would be concern over the adequacy of storage for reasons of national security of supply. Although this would certainly not be a new debate, the appropriateness of intervention may be different when road transport is reliant on the availability of gas or when, nationally, we are largely dependent on energy imports.

Changes in end demand may stimulate the creation of new retail propositions

Changes to end use technologies may lead to the development of new retail propositions (Figure 33).

Figure 33 Drivers of retail propositions

High Hydrogen	Methane Peaking	Regional Gas Grids
Wholesale competition allows for a competitive retail gas market. Similar end use technologies and retail competition may mean propositions are similar to today. The main difference is that retail propositions may be developed to meet demand from both buildings and transport.	Alongside fuel retailers (selling gas by volume), energy services providers may emerge. These respond to the greater complexity and higher capital costs of end use technologies to sell bundles of services (which may include installation of the technologies). They also can optimise fuel switching with hybrid heat pumps, micro CHP or fuel cells, and aggregate these to sell back to the grid. Where retailers cover upfront costs of the end use technologies, regulation may be required to protect customers.	

Source: Frontier Economics

This is particularly likely to be the case where end use technologies span both gas and electricity, either by allowing a choice of input fuel (hybrid heat pumps) or through the use of distributed generation (micro-CHP and fuel cells). In such cases, optimising the decisions of these consumer units is likely to be somewhat complicated, but represent an opportunity for greater system efficiency. For example, effective switching of the input fuel for a hybrid heat pump can allow for lower-cost heat production. Alternatively, careful use of distributed generation might allow for better congestion management on the electricity distribution grid, while aggregated generation could be used to provide ancillary services to the system operator. Energy suppliers might develop retail services that try to capture some of this value by, for example, offering lower cost energy services in exchange for the control necessary to optimise the consumer unit's operation. In some respects this mirrors the sorts of innovative distributed energy services that are already being offered to businesses with behind-the-meter generation.

The higher capital costs of some end use technologies, the demand for consumer finance and the potential scale of the switch in heating technology could lead suppliers to combine traditional fuel supply contracts with financing for the actual heat production technologies (or for connection to heat networks). This could naturally be combined with the sorts of services described above. Encouraging the take up of heat pumps and boilers suitable for the provision of these services might be another motivating factor behind developing propositions of this type.

Greater coordination across the gas and electricity sectors may be desirable

The end use technologies described above, which span the gas and electricity networks, lead to greater interaction between the two markets and may unlock potential efficiencies (Figure 34).

Figure 34 Drivers of greater coordination between the gas and electricity systems

High Hydrogen	Methane Peaking	Regional Gas Grids
Electricity-using electrolysis plants mean some degree of coordination would be helpful.	Hybrid heat pumps allow some short term substitution between gas and electricity for heating buildings.	Micro-CHP and fuel cells allow production of electricity alongside heat.

Source: Frontier Economics

Given this, the system operator of either network, at the very least, needs to be more aware of what is happening with the other fuel, to understand the patterns of demand it observes on its own network. The greater coordination of system operation decisions across networks may also be beneficial. If such decisions are taken in isolation, they are more likely to be inefficient, potentially imposing unobserved costs on the other network. They may also be ineffective, if partially counteracted by activity on the other network[24]. To determine the best option for greater coordination, issues around information sharing, common ownership, the level of independence and the nature of ownership (public or private) will need to be explored. This is therefore one area where significant regulatory changes may be required.

7.2 Strengths and weaknesses of models

In Sections 4-6 above, we presented two market models for each scenario: a market-driven option and an additional-intervention option.

[24] We consider the pros and cons of different coordination options in the transition context, in Section 8.2.2 below.

Each of these models has been designed to meet the needs of market participants in a rational and efficient way, to be stable, and to deliver on policy priorities such as security of supply. However, there are trade-offs between the extent to which the models deliver against each of these aims.

Focussing on the differences between the market-driven and additional-intervention models, we now describe these trade-offs. This appraisal aims to allow the relative attractiveness of the market-driven options and the additional intervention options to be understood.

In particular, we focus on six key differences between the market-driven and additional intervention models:

- support for upstream investors (for example, cap- and floor support for hydrogen producers and CfD support for low carbon methane producers);
- regulation of the transmission network for methane in the High Hydrogen scenario;
- regulation of the hydrogen transmission network as a single monopoly, or a series of CATOs;
- interventions to incentivise storage (for example, compulsory stocking obligations);
- regulated transfer pricing for energy retailers and regulated retail charges; and
- further intervention in system operation.

As described in Section 3, we assess the different options in each of these six areas against a set of criteria agreed with BEIS (Figure 35).

Figure 35 Criteria

Efficiency	Investment environment	Consumer protection and welfare	Political and consumer acceptability	Security of supply	Timelines	Stability and flexibility
Are goods and services produced at minimum cost, and are the right goods and services produced and given to those who value them the most?	To what extent is the model likely to be able to secure investment in the necessary assets and infrastructure, at a cost of capital which minimises the cost to consumers?	To what extent are consumers able to choose freely and effectively among a wide variety of goods and services?	To what extent is the model likely to face marked political or public opposition, or to be politically infeasible?	To what extent is the model likely to ensure that end users do not face either interruptions to supply or costly supply shortages?	How quickly can the model be implemented and does it imply lock-in?	To what extent can the model adapt through changes to political priorities and objectives, technological costs and capabilities, and international market prices?

Source: Frontier Economics

7.2.1 Support for upstream investors

In the additional-intervention model for each scenario, we include an option for upstream investment support. Many options have been studied and demonstrated, particularly in the electricity sector context, and the benefits of certain features, such as including an auctioning element where practical, are well understood. Examples of investor support include the following.

- For hydrogen producers (in High Hydrogen and Regional Gas Grids) support could, include a mechanism which places a cap and floor on returns, to reduce risks faced by investors in the SMR conversion infrastructure. A regime of this type (without auctioning) is currently used to incentivise investment in interconnectors.

- For low carbon methane producers (in Methane Peaking and Regional Gas Grids) support could take the form of CfDs, which essentially guarantee the gas price received by producers. These are currently in place for low carbon generators in the electricity sector.

Figure 36 summarises the strengths and weaknesses of providing additional investor support.

Figure 36 Assessment of support for upstream investors

	Strengths	Weaknesses
Efficiency	Could increase efficiency where alternative options for providing a carbon price signal lack long term credibility.	Shields investors from market signals around the value of the gas they produce. This could lead to inefficient levels of investment.
Investment environment	Reduces revenue risks for investors.	Introduces another element of policy risk, until the contracts are allocated.
Consumer protection and welfare	Increases price stability for consumers.	Generally passes revenue risks from producers to consumers or tax payers, potentially leading to higher costs for consumers.
Political and consumer acceptability	Some consumers (e.g. vulnerable consumers) may value price stability.	May imply a persistent transfer from consumers to low carbon gas producers (though this is likely to be part of any regime to price carbon).
Security of supply	Provides a lever for incentivising further domestic investment.	Not designed to deliver an efficient level of security of supply.
Timelines	Regulatory precedent means investment support could be implemented relatively quickly.	
Stability and flexibility		Changes in external factors such as commodity price shocks could alter the cost of the support borne by taxpayers or consumers.

Source: Frontier Economics

Efficiency

Assuming the climate externality is accurately and credibly priced in the market, the market should deliver efficient investments in hydrogen or low carbon methane production. By tackling the externality directly, a credible carbon price signal would deliver the most efficient market outcome. However, there may be persistent problems with the credibility of the taxes or subsidies used to deliver a long-term carbon price that prevent efficient investments in low carbon gas production. For example, investment in SMR with CCS may be at an inefficiently low level, or priced at an inefficiently high level, if investors perceive that the value of their investment could be affected by a later decision to rely on hydrogen from unabated sources (either domestically or overseas).

Investment support could help bring investment to an efficient level by providing investors with confidence around the value of the low carbon gas they produce, and by shielding them from perceived or real stranding risks.

However by shielding investors from the revenue impacts of competition in the market for gas production there is a risk of over-incentivising investment. The ‘cap’ element of any cap and floor regime may also result in inefficiently low investment levels.

In addition, the use of a volume-linked subsidy helps to stimulate output, but domestic output may be incentivised to inefficient levels. For example, a CfD regime might stimulate excessive domestic production in cases where it would actually be more efficient to buy low carbon gas from abroad, or cause syngas inputs to be redirected from alternative potential uses, like the creation of biofuel.

Investment environment

An investor support regime would be explicitly designed to support investibility and could therefore outperform a purely market approach on this criterion. However, with regimes that involve a cap and floor, developers would still face uncertainty over the revenue they receive within the limits set by the cap and floor, while under most regimes, developers will still face uncertainty as to whether they can gain the support.

In addition under most support regimes, investors also still face operational risks, for example related to the availability of feedstock (for AD and syngas producers) and related to the efficient operation of their gas production plants. However, it would not be efficient to shield developers from these risks, as this would remove their incentive to manage them effectively.

Consumer protection and welfare

Investor support would usually mean that both producers and consumers are insulated from shocks in the actual market price, which is assumed to be set by imported supplies. Some consumers, for example vulnerable or fuel poor customers, may value the stability in final consumer bills that results.

At the same time, insulating producers from revenue risks mean that these risks are ultimately passed on to consumers or tax payers through higher prices or higher taxes. In addition, if any of the inefficiencies discussed above materialise, consumers would bear the resultant increase in costs.

Political and consumer acceptability

Most investor support regimes imply a persistent net transfer from consumers to producers. Where the transfers from consumers to producers are large and conspicuous this could be a source of public opposition. However, any measure to internalise the carbon price is likely to involve a transfer to low carbon energy producers from consumers, while low carbon options remain more expensive than the fossil fuel alternatives.

Such a regime also implies explicit Government support for specific named projects, and possibly for specific technologies. If any of these plants or technologies becomes unpopular, there is a risk that the support regime also faces opposition.

Security of supply

The reduction in risk for investors in gas production associated investor support regimes mean that they can help ensure that sufficient domestic gas production is in place.

An auction or gate process element can provide an additional lever by which the Government could help ensure sufficient production capacity, and the Government could choose to factor security of supply considerations into its assessment of the appropriate amount of capacity to support.

Timelines

Depending on the exact design of the regime, the time to establish it need not be that long given regulatory precedent (for example with the cap and floor regimes for electricity interconnectors and the electricity CfD regime).

Support regimes can be designed so that under 'normal' conditions, they do not imply the transfer of any money (for example a CfD that only tops up the price when it falls below a certain level). This should make it easier to remove if the risk level reduces, compared to some more interventionist options.

The use of auctioning arrangements also means that a regime can be relatively easy to close to new contracts if circumstances change such that the regime is no longer needed.

Stability and flexibility

Under most support regimes, a commodity price shock could significantly alter the implied transfer of funds from consumers to producers, or lead to a series of inefficient production outcomes, potentially undermining consumer support for the regime. The strength of any opposition this generates should be limited however by the fact that any increase in consumer support costs should be offset by falls in the underlying gas price (absent other distortions), such that consumers' bills are no higher overall.

A tax or subsidy in line with the carbon price could be an efficient and flexible support mechanism under these conditions; however, as noted above, there may be issues around the long term credibility of the signal associated with direct carbon pricing options.

7.2.2 Deregulation of the transmission networks for methane in the high hydrogen scenario

As described in Section 4, regulation of the methane network in High Hydrogen may not be required. This is because transmission exclusively feeds SMR plants in this scenario. Since these plants themselves face competition from several sources, the charges that the transmission can sustainably levy are limited by the need not to put the SMR plants out of business.

The strengths and weaknesses of a deregulation of the methane network are set out in Figure 37 and explained further below.

Figure 37 Assessment of regulation of methane network

	Strengths	Weaknesses
Efficiency	Reduces administration costs.	May not result in an efficient level of transmission network charges, as a network monopoly could still charge above efficient levels. Where vertical integration occurs, competition between vertically integrated entities would be possible, but new entities would face barriers to entry.
Investment environment	There is historical precedent of investment being delivered under a vertically integrated structure, in the absence of regulation.	
Consumer protection and welfare	Consumers or taxpayers would benefit from the reduction in administration costs.	Prices are likely to be above the efficient level, leading to higher than efficient prices for consumers.
Political and consumer acceptability		Where the impact of deregulation on prices is significant, this is not likely to be acceptable to consumers.
Security of supply		Higher transmission chargers are likely to have a negative impact on security of supply to the extent that they disincentivise investment in gas production. Vertical integration may create barriers to new entry.
Timelines	Deregulation could be introduced in a relatively timely manner.	It may be more difficult to reintroduce regulation.
Stability and flexibility		The costs and benefits of deregulation would vary in response to external shocks.

Source: Frontier Economics

Efficiency

Deregulation of the methane network may marginally increase efficiency by reducing administration costs and risks around inefficient regulation.

However, the net effect on efficiency is likely to be negative: it is unlikely to result in an efficient level of pricing for the transmission network, as the network would still have monopoly power and could abuse its position up to the limits imposed by the need to keep the SMR plants in business. To the extent that vertical integration can occur, this could introduce an element of competition between vertically integrated entities. However, there would still be barriers to entry for new SMR producers. This could also result in an inefficiently low level of production of hydrogen from SMR.

Investment environment

Historical experience of the roll out of the gas grid in continental north-western Europe suggests that an investment environment could be delivered without regulation of the network monopolies. In this case, competition from a substitute fuel (oil) capped prices for consumers, while investment across the value chain was rolled out under a vertically integrated structure.

If vertical integration is not in place, deregulation of the methane network could result in a less favourable investment environment for SMR plants, given the higher and potentially more uncertain transmission changes that would result from this intervention.

Consumer protection and welfare

To the extent that network deregulation could lead to transmission charges above efficient levels, this is likely to impact negatively on consumers. Higher hydrogen prices are likely to result from the higher costs faced by SMR plants.

These higher prices may be partially balanced by a reduction in tax or charges due to the savings in regulatory administration costs.

Political and consumer acceptability

The degree of political and consumer acceptability is likely to depend on the extent of the impact on hydrogen prices. Where this impact is significant, deregulation is unlikely to be politically attractive or acceptable to consumers, particularly given that many consumers use hydrogen to fuel their vehicles as well.

Security of supply

To the extent that higher transmission charges result, these are likely to have a negative impact on security of supply as at the margin, they may disincentivise investment in SMR production.

Timelines

Deregulating the transmission network could be done over a relatively short period. The reintroduction of regulation, if required, would be more challenging.

Stability and flexibility

The costs and benefits of deregulation to GB society would change in the face of external shocks, such as major changes in commodity prices. For example, in response to a fall in the price of natural gas, the network could increase its charging without putting SMR out of business. Any decision to deregulate the network should therefore look at a range of scenarios for commodity prices and other external factors.

7.2.3 Regulation of the hydrogen transmission network as a single monopoly, or a series of CATOs

In the High Hydrogen and Regional Gas Grid scenarios, the hydrogen transmission network would need to be regulated in a similar way to the methane transmission network today, given its natural monopoly characteristics. In the market driven models for each of these scenarios, we assume that the construction of the hydrogen transmission network in the transition was carried out by a series of CATOs, which own and operate distinct pieces of the network in the steady state. In the additional-intervention models we assume a single monopoly owns the network.

Figure 38 looks at the strengths and weaknesses of a transmission network owned by a series of CATOs, compared to one owned by a single monopoly.

Figure 38 Assessment of CATOs

	Strengths	Weaknesses
Efficiency	Positive impact on efficiency by allowing the regulator to benchmark performance. Tendered competition for new investments would also increase efficiency.	Negative impact on efficiency as the additional complexity could bring additional transaction costs, lost synergies and operational inefficiencies.
Investment environment	Operational risks could be mitigated by the use of long term (e.g. 20 year) contracts.	Inefficiencies could raise costs and introduce new operational risks.
Consumer protection and welfare and political and consumer acceptability	Positive impacts on competition would have benefits.	New operational risks could have a negative impact.
Security of supply		Imperfect coordination could introduce new security of supply risks.
Timelines	If CATOs have been used in the transition to construct the hydrogen transmission network, it may be simpler to stick with them.	
Stability and flexibility	Neutral.	Neutral.

Source: Frontier Economics

Efficiency

As described above, the CATO model has the potential to increase efficiency. This is because it would allow the regulator to benchmark performance between different transmission owners, and also could allow competitive regulatory rewards.

However, the presence of CATOs could also involve inefficiencies and additional transaction costs, including[25]:

- interface costs borne by the system operator (and other stakeholders) in working with a set of new CATO entities;
- lost synergies in construction or operation of assets, arising from lost scale and diversity of projects;
- inefficiencies in the operation of the transmission system due to communication barriers and/or imperfect incentives leading to certain failures of coordination.

Investment environment

The impact on the investment environment for gas producers is likely to depend mainly on the extent and nature of the impact of CATOs on efficiency, as described above. To the extent that the presence of CATOs results in inefficiencies and higher prices, the impact on the investment environment is likely to be negative.

On the other hand, competition for new network investments is likely to drive increases in efficiency, which would have a positive impact on the investment environment.

Inefficiencies in the operation of the transmission system could also have a negative impact on the investment environment, if they increase connection risks and operational risks for upstream investors.

Consumer protection and welfare and political and consumer acceptability

Once again, the impact on consumers and the degree of political and consumer acceptability is likely to depend on the extent and nature of the impact on efficiency, and therefore on the costs faced by consumers.

Security of supply

As described above, CATOs may impact on the operation of the transmission system, if communication barriers and/or imperfect incentives lead to failures of coordination. This could introduce additional security of supply risks.

Timelines

If CATOs have been employed to deliver investment in the transition, it may be simpler to stick to this model, rather than moving to a single monopoly.

Stability and flexibility

Both CATOs and a single national monopoly could be stable and flexible in the face of external shocks (such as a commodity price shock).

7.2.4 Intervention to incentivise storage

The market-driven models for each scenario assume that that storage is commercially provided through a competitive market, as it is today. In this case, the quantity of the quantity of low carbon gas that traders choose to store ultimately reflects the financial costs they face in the event of a shortfall.

[25] Frontier Economics (2016), *A cost benefit analysis of the potential introduction of CATOs*, https://www.ofgem.gov.uk/ofgem-publications/98418/ngresponseappendix2fronteireconomicsrpt-catocba-080116-final-pdf

However, market and regulatory failures may mean that a competitive market underprovides storage. Because of this, the Government may prefer to intervene to enhance security of supply by, for example, setting out a minimum amount of gas that must be stored. There are a range of options for this, including the use of compulsory stocking obligations like those that exist for petroleum products, with the storage obligation effectively dispersed among retailers and the cost passed ultimately to consumers (Figure 39).

Figure 39 Assessment of further intervention to incentivise storage

	Strengths	Weaknesses
Efficiency	Without intervention, market and regulatory failures may mean that investors are not fully compensated for the insurance, system and arbitrage value of storage, leading to underinvestment in the market.	An obligation set at the wrong level could reduce efficiency.
Investment environment	A stable and credible obligation is likely to improve the investment environment.	
Consumer protection and welfare	To the extent that the obligation increases efficiency, consumers benefit.	An obligation set at too high a level, would result in higher costs for consumers.
Political and consumer acceptability	Additional control of security of supply is likely to be attractive to consumers.	If costs are high, this would limit acceptability.
Security of supply	The intervention is designed to increase security of supply.	
Timelines	Regulatory precedent means that this could be introduced quickly.	
Stability and flexibility	The market should be able to respond flexibly to commodity and technology cost shocks.	

Source: Frontier Economics

Efficiency

Intervention may increase efficiency, given the presence of market and regulatory failures in the following areas:

- **Insurance value of storage.** Intervention could increase efficiency if in the absence of this intervention (i) traders do not face the wider social costs of shortages through regulated penalties for shortfalls (which is plausible, since even if price signals are in place, penalties may simply cause the traders to go bankrupt in the event of a shortage, without materially improving security of supply) and (ii) the traders are not capable of accurately assessing the risk of a shortfall (which again is plausible, since traders may not be able to suitably quantify the risks of extreme, unprecedented supply events. If the Government were better able to assess the costs and risks of a shortfall, it might be more efficient for it to determine the optimal aggregate level of storage. Ultimately, the efficiency trade-off in this area comes down to whether the Government can impose credible penalties on traders in the event of a shortage and who is best placed to determine the genuinely efficient social level of storage.

- **System value of storage.** Storage can increase usable system capacity at key bottlenecks and help to manage congestion. In this way, it can be a substitute for network investment. However, given uncompetitive markets in network capacity, investors in storage may not receive full compensation associated with this value, and therefore the competitive market may under deliver relative to the efficient level.
- **Arbitrage value of storage.** If wholesale markets are illiquid over some or all of the forward market (as they are today), investors in storage may not be able to gain the full arbitrage value of storage. Once again, this means underinvestment in storage, relative to the efficient level.

Provided secure and flexible arrangements are in place for meeting the obligation, the effect of the intervention would simply be to boost aggregate demand for storage to the efficient level, with delivery still achieved through competitive market processes.

Security of supply could potentially also be enhanced through other means, like building additional production, network and import capacity. The ideal approach in terms of efficiency would therefore be to develop a security product that could be arbitraged across all these potential sources of security. However, this approach is untested and would require significant policy development to ensure its effectiveness.

Investment environment

To the extent that the intervention regime is stable and credible, with an established track record, it is likely to encourage investor certainty and support the investment environment for storage.

Consumer protection and welfare

Consumers' welfare is supported by the provision of an efficient level of security of supply, which they ultimately pay for. Therefore consumers' interests are fully aligned with the delivery of an efficient level of security, as discussed above.

Political and consumer acceptability

Interventions already exist for petroleum products and Ministers may like the additional control this gives over security of supply.

Security of supply

This is designed to deliver enhanced security of supply relative to a market-driven approach.

Timelines

The regulatory arrangements underpinning an intervention such as a compulsory stocking obligation could be delivered fairly quickly, borrowing on regulatory precedent for petroleum products. In practice, the real constraints to achieving enhanced security of supply are physical and linked to whether investment in new storage capacity is needed and how quickly reserves can be built up. The implementation of a new obligation would need to allow for these practical constraints, which themselves depend on the scale of the change in stocking behaviour that is required.

Stability and flexibility

Since an intervention could be designed to still give parties flexibility as to how storage increases (for example, by building or contracting third parties for storage capacity), the market should still be appropriately responding to commodity and technology cost shocks. Provided the target-setting process is insulated from excessive political interference, the regime should be reasonably stable and provide investor confidence.

7.2.5 Regulated transfer pricing for energy retailers

A degree of lock-in to retail contracts may be required where suppliers are offering propositions that fund the installation of end use equipment, or are providing related equipment designed to allow for the more effective use of the underlying heat and power system. This is particularly relevant for two of the scenarios, which include more complex and capital-intensive technologies that interact with both the gas and electricity systems:

- in Methane Peaking, the main driver is the use of hybrid heat pumps; and
- in Regional Gas Grids, the main driver is the use of fuel cells or micro-CHP to provide distributed generation.

Where energy services providers develop propositions that rely on a degree of customer lock-in, there may be value in additional government intervention that either facilitates switching for customers who are locked-in, or else protects them from excessive prices. Our appraisal of this intervention is set out in Figure 40.

Figure 40 Assessment of regulated transfer pricing for energy retailers

	Strengths	Weaknesses
Efficiency	Could be required to facilitate retail competition, where funding of end use technologies implies lock-in to long term contracts.	There is a risk that asset prices are not set at the right level, This would undermine competition and efficiency.
Investment environment		Investments in innovative new retail propositions may be curtailed.
Consumer protection and welfare	If lock-in to long term contracts is reducing competition, then these measures increase consumer protection.	
Political and consumer acceptability		Developing transfer pricing could cause controversy, given the relatively high value of the kit.
Security of supply	No impact expected.	
Timelines		Estimating the appropriate prices could take time.
Stability and flexibility	No impact expected.	

Source: Frontier Economics

Efficiency

The efficiency benefit of these interventions depend on whether or not the changes to the retail market that are triggered by the scenarios undermine retail competition.

Developing regulated prices for the end use technologies in people's homes may be complex and subject to regulatory failure, given the variety of models likely to be on the market. However, retailers would have an incentive to work with the Government to ensure that any transfer prices are appropriate, since they may be on either side of the customer switch.

If asset transfer prices are not set appropriately, they would fail to facilitate competition. If regulated charges were set too high, consumers would end up paying too much. Too low, by comparison, and there would be insufficient investment in energy services packages and unexploited efficiencies that these services could bring.

Investment environment

The presence of regulated returns in retail could dissuade retail investments in, for example the development of new propositions and business models, since the retailer could not be certain that the regulatory charges would adapt to allow for a return on these investments.

Consumer protection and welfare

Where lock-in to energy service tariffs is leading to the exploitation of consumers, consumer protection would be enhanced by these measures, relative to the market-driven approach. The regulated transfer pricing approach attempts to override the need for contract lock-ins and to allow for effective competition. If it works, it should be fairly effective at maximising consumer welfare.

Political and consumer acceptability

Developing regulated charging may be complex, given the relatively high value of the kit and the number of models likely to be on the market.

Timelines

There is precedent for regulated transfer pricing which should allow the necessary regulation to be developed fairly rapidly. However, before the policy can be implemented, the transfer prices themselves need to be set. Though the industry should be able to support the development of these prices, they cannot be developed before it is clear what the relevant assets are. This price list would also need to be kept under review to account for the use of new technologies or for changes in the value of existing asset types.

Stability and flexibility

Regulation for the purpose of asset transfers is unlikely to be affected by external price shocks.

7.2.6 Further intervention on system operation

Since the system operator’s role involves overseeing the system as a whole, it needs to be a single body for reasons of operational necessity. Therefore a fully market driven approach is not possible, and a minimum level of regulation is required if it is to be privately-owned.

Under the market-driven models for each scenario, the system operator is assumed to be a privately-owned regulated monopoly, as it is today. However, as the complexity of the system increases (for example requiring coordination across multiple energy vectors), the Government may conclude that regulation cannot provide a privately-owned system operator with fully efficient incentives and that the system operator function requires much closer oversight, or is even conducted by public body. This is particularly relevant for the Methane Peaking and Regional Gas Grids scenarios, both of which involve end use technologies which lead to greater interactions between the electricity and gas sectors.

We now assess further intervention. For illustration and to draw out the most differences between potential approaches, we use the relatively extreme case of public ownership as an example (Figure 41).

Figure 41 Assessment of further intervention on system operation

	Strengths	Weaknesses
Efficiency	Avoid the risks of designing inefficient regulatory incentives.	Inefficiencies may result from political influence, inability to pay and attract top staff, linkages to the political cycle, including periods of inability to make and public decisions.
Investment environment	Direct management of regulatory risk could reduce the cost of capital.	Bureaucratic hurdles may reduce the ability to get approval for investments.
Consumer protection and welfare	Depends on the impact on efficiency.	
Political and consumer acceptability		
Security of supply	Either option could delivery security of supply.	
Timelines		Would require time to establish governance arrangements.
Stability and flexibility	Either option is likely to be robust to shocks.	

Source: Frontier Economics

Efficiency

The efficiency merits of public or private ownership depends on whether or not regulatory incentives can be effectively designed to motivate efficient system operator behaviour. Where this is possible, private ownership is likely to help drive low-cost provision. Where it is not possible, public ownership could increase efficiency. However, there are likely to be operational inefficiencies associated with public ownership. These would include the risk of political influence, linkages to the political cycle (which may result in periods of inertia), and inability to pay and attract top staff.

Investment environment

A publically owned system operator may be able to borrow more cheaply, to the extent that it can directly manage regulatory risk associated with its investment decisions. However a public body may also face additional bureaucratic hurdles to get approval for genuinely efficient investments.

If large investments are required in system operation, private ownership could be preferred as the necessary capital could be raised without seriously affecting the Government's balance sheet. However, the scale of investments required in system operation is not expected to be so large that the effect on the public balance sheet is likely to be an issue.

The impacts on investment across the value chain depend on the extent to which a publically owned system operator increases efficiency, and the effect that this has on charges.

Political and consumer acceptability

Consumer acceptability depends on the cost of achieving public control and the way that this public cost is funded.

Security of supply

It is not clear that either option is inherently better at delivering security of supply. Ultimately, it depends on the extent to which the regulatory or organisational incentives on the system operator accurately reflect the value of security of supply.

Timelines

Changing the ownership of the system operator would take time to realise given the need to establish appropriate governance structures for a public body. The key driver of any change is likely to be the transition rather than the steady state, since it is at this point that the system operator's planning role is at its most challenging and critical, conflicts of interest in planning become most severe, and the rapid pace of change make establishing efficient long-term regulatory incentives the most difficult. These issues are therefore likely to be the most important trigger points for any change.

Stability and flexibility

The choice of system operator structure is likely to be fairly robust to technology and commodity costs.

8 TRANSITION PATHWAYS

We have established that in the 2050 steady state, markets for a low carbon gas system could function in similar ways to energy markets today, though some significant new regulatory intervention may be required, depending on policy preferences around risk (Section 7).

However, while market and regulatory models do not need to be fundamentally altered by 2050, the infrastructure and technologies across the value chain will need to be radically transformed.

This section looks at this transformation, with the aim of identifying actions that could help manage the associated challenges, risks and uncertainties and deliver the investment required.

- In Section 8.1, we look at the investment pathways required to achieve each low carbon gas scenario, to identify key issues that arise in the transition.
- Having understood the key issues, we then set out potential actions in Section 8.2.
- Finally, we provide a summary in Section 8.3.

8.1 Investment pathways

To understand the challenges, risks and uncertainties in the transition to a low carbon gas system, we first need to identify the investment pathways associated with each scenario.

For each 2050 scenario[26], Aqua Consultants has developed illustrative pathways for the investments required. These pathways are not based on detailed analysis of the least-cost pathway. Rather they are meant to provide a high-level illustration of the timing, scale and interdependencies of the investment required to move to each low carbon gas scenario.

We now describe the key features of the pathway to each scenario, looking at the following elements:

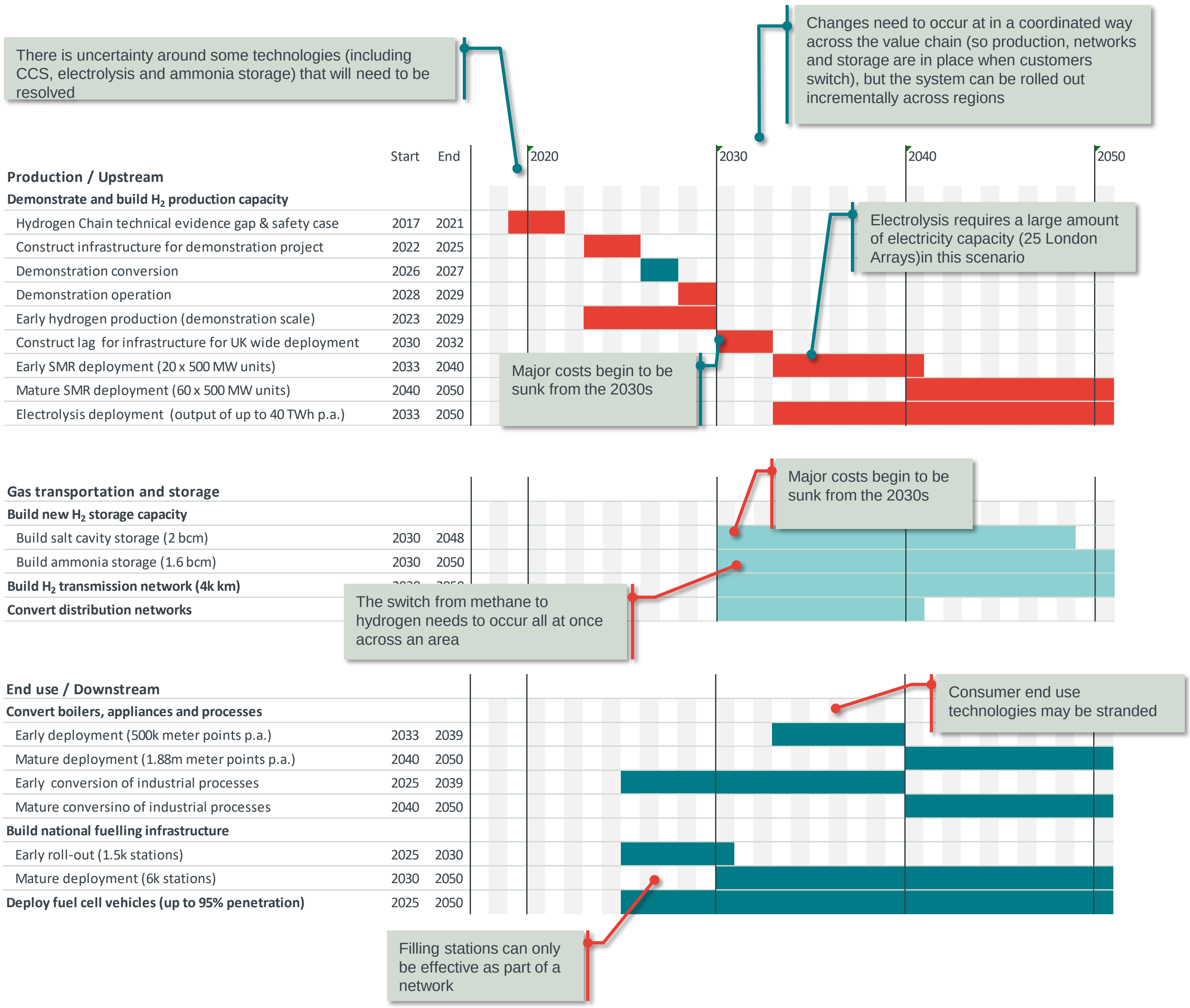
- required investment;
- interdependencies;
- key decision points;
- impacts on consumers; and
- key areas of uncertainty.

[26] As set out in Section 2, these scenarios should not be construed as reflecting an attempt to forecast the most likely target-consistent outcomes, or even the most desirable 2050 outcomes. Rather they have been developed specifically to stimulate and test thinking on the appropriate market and regulatory models in 2050.

8.1.1 High Hydrogen

Figure 42 describes the gas system investment pathway for the High Hydrogen scenario[27]. This illustrates the physical investments required to move from the current gas system to a system where hydrogen meets demand for heat in buildings and industry and provides a fuel for road transport (see Section 4 for more details on the scenario). Crucially, Figure 42 does not cover the time needed to develop any policy instruments, regulatory certainty, consumer buy-in or investor confidence required to achieve these physical investments. As discussed below, these may take several years to realise.

Figure 42 High Hydrogen: gas sector investment pathway



Source: Frontier Economics and Aqua Consultants

[27] Complementary investments required in the electricity and CCS sectors are not shown in Figure 42.

What investment is required?

Figure 42 illustrates that major investment is required to realise this scenario.

- **Near term** – Investment begins with an end-to-end demonstration of a hydrogen system. To lay the groundwork for the large-scale investments needed in production and transmission, it is likely that demonstration work would need to be completed in advance of any decision to start building a national transmission network or to convert multiple cities. Assuming that scale demonstration would take at least six years to plan and commission, and that it would be valuable to run it for more than a year, a decision on demonstration would need to be taken in the near term. To realise a significant hydrogen demonstration project, the UK would need to demonstrate the safety case, close some technical evidence gaps and develop a funding mechanism to support work of this type. In addition, before starting to build the hydrogen transmission infrastructure around 2030, it would be useful to have more information on the costs and viability of CCS, electrolysis and hydrogen storage. This implies that progress will have been made on the feasibility and costs of these technologies by 2030. Research programmes to provide this information would need to be established several years earlier.
- **2030-2040** – Two new 500 MW SMR plants could be required per year from 2030-2040, alongside initial investment in electrolysis. Stimulating first-mover investments of this type is likely to require the prior development of policy mechanisms to shelter investors from some of the associated policy risk and possibly even the creation of an explicit support/subsidy regime. Work on the hydrogen NTS also will have to begin in this period[28] - even assuming efficient design, the seasonal nature of construction means that building a new NTS could take around 20 years. Where this construction work is tendered, the associated process would need to be developed and run in advance of this. Investment in storage capacity also starts in this period. Mass end user conversions would begin and average about 11,000 households a week. By this point therefore, a coordinated conversion process would need to be in place, bringing together the fitters, networks, equipment manufactures and possibly the financiers and regulator/government. The conversion requires work within people's homes and some investment in distribution networks. Roll out of hydrogen filling stations continues at an increased pace. This could either be driven by incentives to drive the take-up of vehicles or direct support for the creation of the filling station network.
- **2040-2050** – Investment intensifies in this period. Upstream investment in gas production increases to six 500 MW SMR plants built a year, alongside further investment in electrolysis, the construction of hydrogen import terminals and increased investment in storage. At this point, there would be viable commercial businesses involved in the production of hydrogen that provide solid evidence to the investor community of the commercial viability

[28] A new hydrogen NTS is required because the existing NTS is generally constructed of steel, and is therefore unsuitable for transporting hydrogen due to risk of hydrogen embrittlement. It is also likely that the existing NTS capacity will be required to supply natural gas for hydrogen production.

of investments in the hydrogen supply chain. End use and distribution network conversions accelerate to average about 37,500 households a week.

There are no obvious physical constraints to realising this scenario in the time to 2050. There is precedent for major transformations of infrastructure (such as the switch to North Sea gas) and given the characteristics of SMR, electrolysis and pipeline technologies there is no obvious reason why petro-chemical supply chains should not be able to expand to deliver the required build rates.

However, the feasibility of delivering this scenario is, of course, not certain. As discussed below, there are still major uncertainties around the costs and feasibilities of some of the key technologies, such as CCS. In addition, a build rate of this intensity will require strong consumer and investor buy-in. We discuss the risks and challenges associated with gaining this buy in in Section 8.2.

Where are the interdependencies?

There are several important interdependencies in this investment path.

- **Value chain coordination** – Changes need to occur in a coordinated way across the value chain. The value to parties upstream and downstream largely depends on networks being in place. End use conversions cannot take place until hydrogen production capacity is in place. Without end use conversions and action in gas transport, the value of the hydrogen produced may be limited (though there are some alternative uses, such as in electricity storage).
- **Simultaneous switching** – Since the same pipe infrastructure cannot transport both hydrogen and methane to customers simultaneously[29], at least one or two thousand customers will need to be switched from natural gas to hydrogen at the same time (unless hydrogen boilers are available – see Section 8.2.1).
- **Coordination with other sectors** – CCS is required for this scenario to be viable in a low carbon world. Coordination will therefore be required with the CCS sector, in particular to ensure that SMR plants are located where it is feasible and cost-effective to transport the carbon produced. Coordination is also required with the electricity sector. The scale of electrolysis[30] in this scenario implies the need for a lot of low carbon generation capacity to be developed in parallel (c. 3 nuclear stations or 25 London Arrays).

Are there key decision points?

It is important to consider lead times, sequencing and optionality when thinking about the decision points.

- **Lead times** – The major capital investments associated with this scenario are likely to have investment lead times of between 2-5 years. In advance of this, further time may be required to achieve customer buy in and to

[29] While it may be technically possible to mix hydrogen and methane, it would not be possible to transport high concentrations of each gas to consumers simultaneously

[30] Electrolysis is assumed to be c. 75% efficient.

prepare regulatory and policy frameworks, potentially including major stakeholder engagement.

- **Sequencing** – While a number of activities can happen in parallel – e.g. preparation, planning and early deployment of technologies, the sequence is important in other areas. For example, consumers will not be able to switch to hydrogen until upstream production or import capability is in place. Similarly, upstream investors may not wish to commit funds until they can be assured of some final demand. To overcome this problem, the Government may to choose to effectively guarantee some level of hydrogen conversion to potential investors in upstream production. This guarantee could take the form or an implementation agreement as discussed further in Section 8.
- **Optionality** – To some extent, incremental roll out is possible in this scenario[31]. Roll out of end use conversion and production is reasonably granular and so could be stopped partway in response to changes in, for example, technology costs. Where roll out is stopped part way, there may be distributional issue – for example a set of customers already connected to hydrogen who end up paying substantially more. These issues could be addressed through transfers to help with ongoing costs, or socialisation of costs that have already been sunk (through network charging or through the taxation system). The least granular part of investment relates to the transmission infrastructure. This is harder to roll out incrementally, although even this could be scaled back to give sub-national coverage where conversion was already complete.

Given investment lead times, it is unlikely that multiple pathways can be followed much beyond the mid to late 2020s while still allowing for the completion of a full hydrogen conversion by 2050. This is because large hydrogen investments begin to be sunk from around 2030. However, the strategy could be adjusted as new information comes through over the next decades.

Up until 2030 those investments that do occur are largely around demonstration. While these investments could still end up being stranded, they can at least be justified because of their value in terms of informing the critical decisions made in the early 2020s.

How might consumers be impacted?

Hydrogen end use technologies are likely to provide a similar level of functionality to standard methane boilers. However, there may be important issues around choice, asset stranding, cost, as well as disruption during the switchover to new end use technologies.

- **Change in the set of available technologies** – When an area switches to hydrogen, the option to remain on the methane network will no longer be available as the same pipe infrastructure cannot transport both gases simultaneously. Consumers will therefore face a change in the set of

31 The H21 Leeds City Gate project provides an example of this.

technologies that they can choose from (though we recognise they may be indifferent to the change in vector gas).

- **The risk of asset stranding and disruption** – The need for simultaneous switching means that it may also not be possible to allow consumers to switch when their existing assets have reached the end of their lives. This could lead to the stranding of existing assets, and disruption for consumers, since it may not be possible for consumers to switch over end use technologies at a time of their choosing. We discuss some technical options for mitigating this, for example hydrogen-ready boilers or the provision of bottled gas in Section 8.2.1. Significant disruption could also occur where service pipework within homes needs checking for leaks and then potentially upgrading (due the smaller molecular size of hydrogen relative to methane).
- **Costs** – Customers will face different upfront and running costs. While the long-term costs of hydrogen and hydrogen boilers are highly uncertain, hydrogen is likely to be more expensive than natural gas, at least at the start of the transition. The costs of hydrogen produced from SMR will necessarily be higher than methane alone, since methane is the feedstock used, but, over time, electrolysis has the potential to reduce the costs.
- **Fairness** – Incremental roll out by region means that the impact of the transition to hydrogen on consumers is likely to vary by geography as well as across time. Early in the transition, hydrogen will cost more than methane, if, as expected, hydrogen is produced from SMR, although this may change over time. In addition, hydrogen boilers in the short run are likely to cost more than gas boilers (for reasons of technology maturity and economies of scale), but the costs could be expected to fall over time as the technology matures. These differences in costs will result in both temporal and regional inequalities in the costs faced by consumers.
- **Safety** – The combustion risk from natural gas or hydrogen leaks in the house are estimated to be broadly similar despite the differing properties of both gases[32]. However, a move to hydrogen will improve some aspects of safety since carbon monoxide poisoning will no longer be a risk. On the other hand, colouring hydrogen to ensure flames are visible may not be feasible. Even if hydrogen is as safe or safer than natural gas, given its novelty in the heating context, any accidents that occur early in the conversion process could have a major impact on public acceptability.

What are the key areas of uncertainty?

There is a huge degree of uncertainty around the transition, around costs, technological feasibility, and consumer preferences, all of which could be affected by economic, technical and political developments as well as unforeseen events.

- **Feasibility** – A hydrogen gas system has not yet been demonstrated from end to end. There is also uncertainty around some specific technologies that have not yet been demonstrated at scale. The most important of these is likely to be CCS, as without the availability of CCS, hydrogen production

[32] Evidence cited in Sustainable Gas Institute and Imperial College London (2017), *A greener gas grid:what are the options?*

from SMR will not be consistent with meeting carbon budgets. Ammonia storage also needs to be demonstrated at scale.

- **Costs** – There is a large degree of uncertainty about the absolute and relative costs of technologies across the value chain. For example, while SMR at present looks like it might be the most cost-effective technology for hydrogen production, imports or electrolysis may turn out to be more competitive. It is also not clear whether pursuing a hydrogen strategy would be more cost-effective than, for example, an electrification strategy.
- **Disruptive technologies** – There is also the potential for disruptive technologies to enter the mix – for example heating technologies such as smart clothing[33] could reduce the value of low carbon gas.
- **Consumer preferences** – The degree of consumer acceptance of new technologies and vector fuels is also not yet clear.

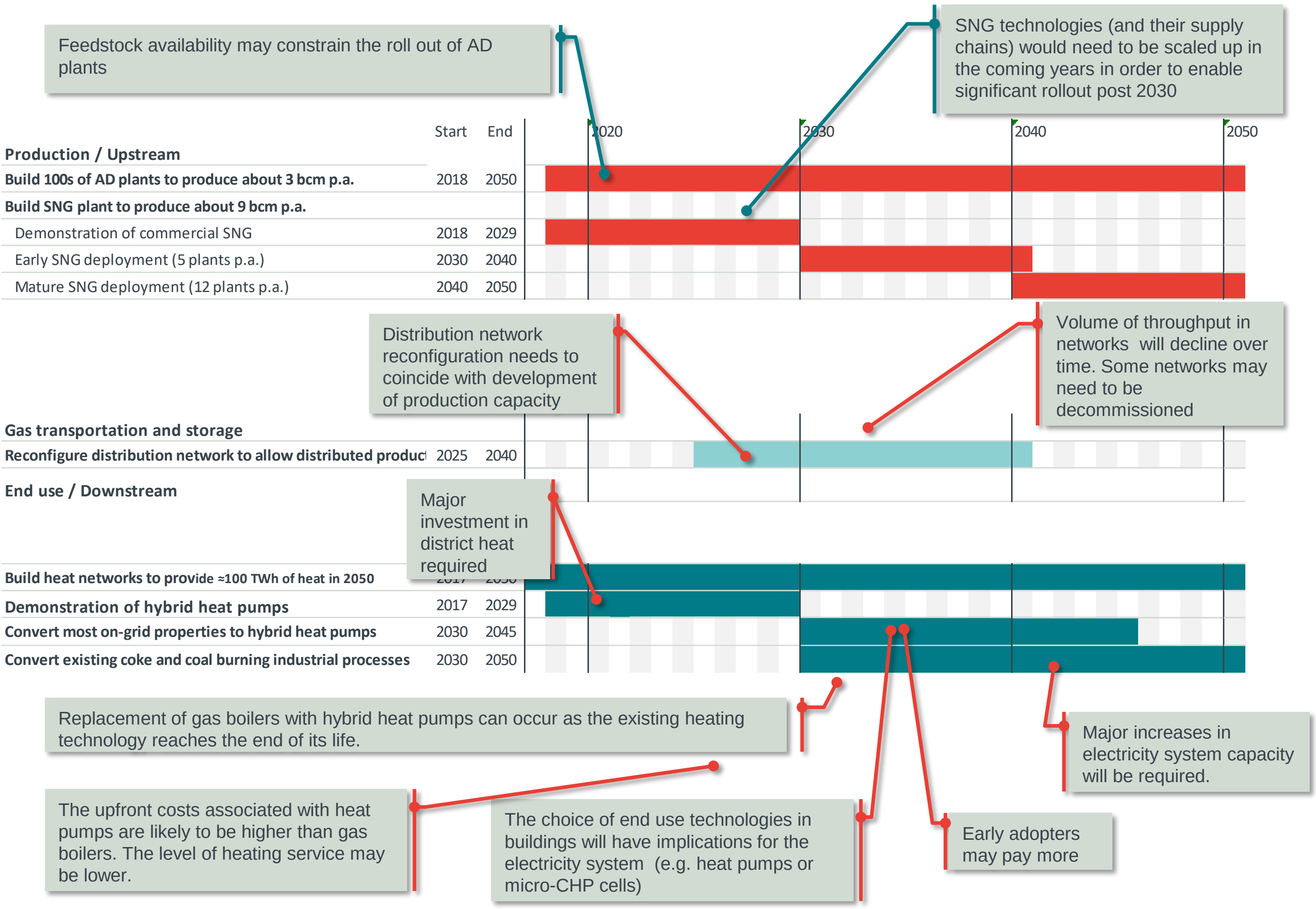
We discuss the consequences of these areas of uncertainty in Section 8.2.1 below.

8.1.2 Methane Peaking

Figure 43 shows the gas sector investment pathway for Methane Peaking. This illustrates the physical investments required to move from the current gas system to a system where low carbon methane meets peak heat demand in buildings via hybrid heat pumps as well as the demand for gas in industry. Once again, it does not cover the time needed to develop any policy instruments, regulatory certainty, consumer buy in or investor confidence that might be required to achieve these physical investments.

[33] http://www.pocket-lint.com/news/132392-future-clothing-is-here-nanowires-used-to-keep-heat-in-and-even-generate-warmth

Figure 43 Methane Peaking: gas sector investment pathway



Source: Frontier Economics and Aqua Consultants

What investment is required?

The scenario is characterised by the following.

- Deployment of capital-intensive technologies like AD and heat networks continues incrementally throughout the period to 2050, accelerating over time, with major costs sunk from the 2030s.
- From 2030, comparatively large-scale syngas facilities also start to be deployed and gas distribution networks start to be reconfigured to allow for significantly greater bi-directional gas flows. For this to happen, more work on the commercial viability of syngas will need to be undertaken in advance, Since the initial deployment of these plants may be subsidised initially, it will also be important that the sustainability case of different forms of syngas are properly understand and that clear and credible sustainability standards are put in place
- Demonstration and further development of hybrid heat pumps continues from now. The installation of hybrid heat pumps occurs over a period of about 20 years as people replace existing systems that reach the end of their useful lives. For this end use transition to occur, policies will need to be implemented to either drive take-up, or else to mandate it. It may also be necessary to facilitate

changes to the supply chain that prepare existing and future boiler engineers for the work of changing end use heating technologies.

Once again, there are no obvious physical constraints to realising this scenario in the time to 2050. This scenario involves far less significant infrastructure investments within the gas system than High Hydrogen, and allows greater scope for delay. However, there is a corresponding increase in the need to deploy low carbon generation capacity and electricity network upgrades to support the greater use of electricity in heat generation. The required electricity sector investment is outside the scope of this project. However, the fact that electricity sector investment is likely to impose major costs and challenges for the energy system in this scenario should not be disregarded.

Within the gas and heat sector, the biggest investments relate to the rollout of heat networks and to the conversion of end-use heating.

Again, even just looking within the gas sector, the feasibility of delivering this scenario is not certain. As set out below, there are still major uncertainties, for example around the availability of sustainable feedstock as well as major risks and challenges around gaining consumer and investor buy-in (discussed in Section 8.2).

Where are the interdependencies?

As there is no limit to the extent to which low carbon methane can be blended with natural gas, and since end use technologies do not need to be adjusted, the coordination required within the gas system for this scenario is less significant than for the high hydrogen scenario. However, there will be a need for coordination between network investment and investment in gas production, as distribution network reconfiguration is a prerequisite for the significant development of distributed production capacity.

In addition, the use of hybrid heat pumps means that coordination requirements with the electricity sector are highly significant. In particular, electricity grid and generation capacity will need to be in place to enable roll out of heat pumps, and links between the electricity and gas sectors will be required to ensure efficient use of these technologies. For example, to facilitate efficient switching consumers must be able to see cost-reflective electricity and gas price signals. These signals will also need to be relatively granular (for example time of use signals based on hourly or daily prices – see Box 4, Section 5)

Coordination will also be required with the district heating sector, to ensure that investment in network upgrades takes account of the likely development of district heating in localities where it is cost-effective.

Are there key decision points?

The nature of the changes involved to the gas system is more continual and gradual in this scenario compared to High Hydrogen, with no points where option value diminishes suddenly.

However, given the scale of change required in the electricity sector, and the lead times for this investment, decisions to pursue this strategy may be required in the late 2020s.

To keep the option of pursuing this scenario open, early investment in demonstration of syngas will also be required.

As is true across all of the scenarios, it is unlikely that multiple pathways can be followed much beyond the mid to late 2020s while still allowing for the completion of a full hydrogen conversion by 2050. In addition, in order to follow multiple pathways it would be necessary to begin the process of scale hydrogen demonstration included in the other scenarios but excluded from Figure 43 above.

How might consumers be impacted?

Because simultaneous switching is not required in this scenario, consumers may have a greater choice over when they move to the low carbon technologies. To some extent, the installation of hybrid heat pumps could occur as people replace existing systems that reach the end of their useful lives. However, requirements to upgrade the electricity grid may impact on the extent to which this is possible.

In terms of functionality and customer experience, hybrid heat pumps are likely to represent a more significant change for customers than hydrogen boilers. Compared to gas boilers, heat pumps may take up more space, they may be noisier, and they may provide lower grade heat, meaning that they are less responsive. Hybrid heat pumps are also likely to entail higher upfront costs, and significant insulation and changes to radiators may be required alongside their installation, leading to potentially high levels of disruption for consumers.

What are the key areas of uncertainty

As with the High Hydrogen scenario, there is a huge degree of uncertainty around the transition, around costs, technological feasibility, and consumer preferences. As discussed above, all of these may be affected by unforeseen events or the entry into the market of disruptive technologies.

There is particular uncertainty around the costs and feasibility of different syngas production technologies, and on the relative cost of imports of low carbon methane. Key risks also relate to feedstock availability for the production of low carbon methane. Given the scale of the production of gas, it is likely that biomass is being imported in order to create sustainable gas.

There are also significant uncertainties around the cost and feasibility of hybrid heat pumps, with only one major trial currently underway to demonstrate these in the UK[34].

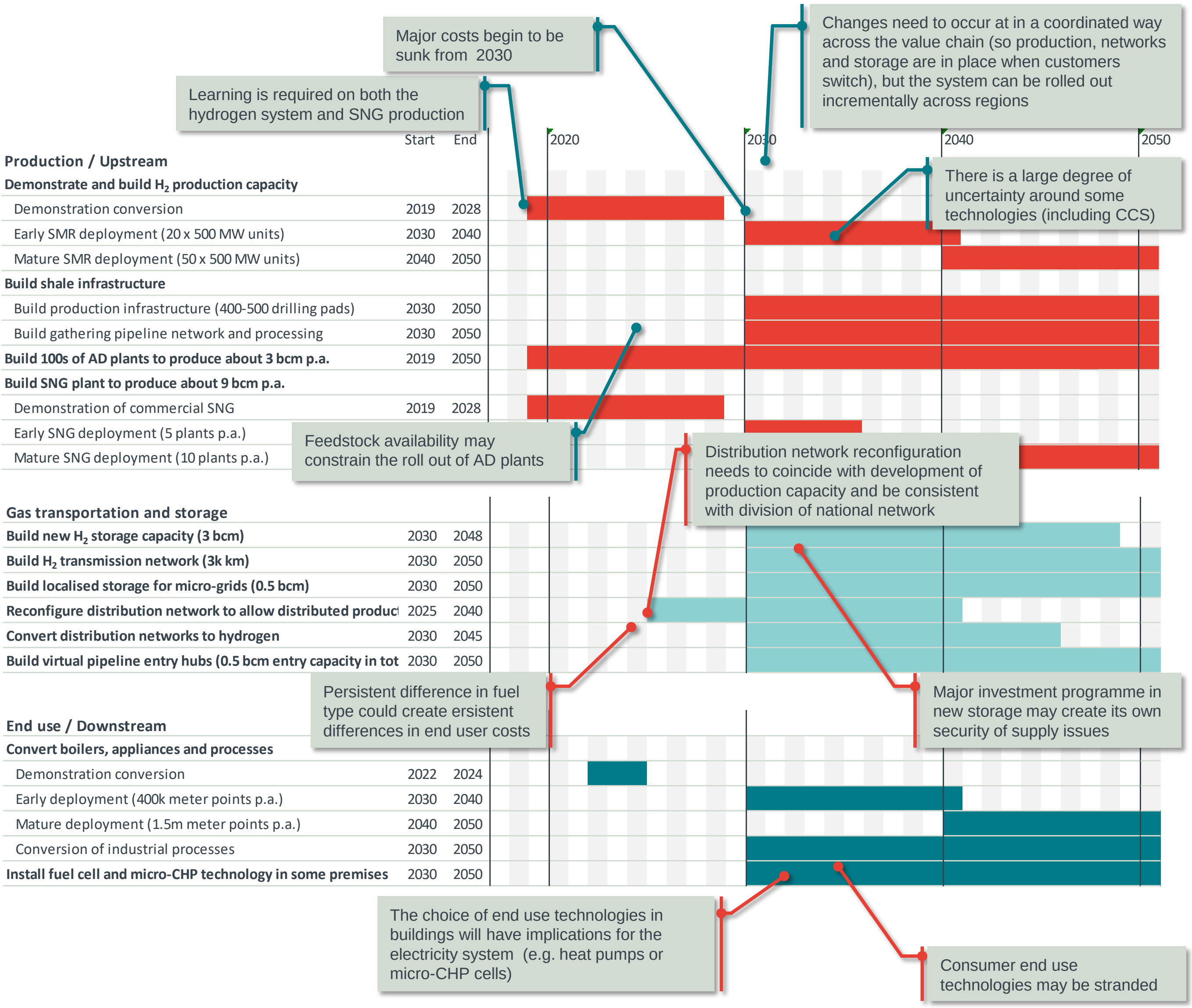
Once again, consumer preferences are another area of major uncertainty, in particular the likely acceptability of hybrid heat pumps, for example, in terms of their functionality, and the space they take up.

34 https://www.westernpowerinnovation.co.uk/Projects/Current-Projects/FREEDOM.aspx

8.1.3 Regional Gas Grids

Our third scenario is based around dividing the distribution network between areas that use hydrogen and others that use low carbon methane and electricity (Figure 44). Again, this shows the physical pathway only and does not cover the time needed to develop any policy instruments, regulatory certainty, consumer buy in or investor confidence required to achieve these physical investments.

Figure 44 Regional Gas Grids: Investment Pathway



Source: Frontier Economics and Aqua Consultants

Regional Gas Grids combines many elements from the High Hydrogen and Methane Peaking scenarios. We therefore focus here on the areas where there are differences.

What investment is required?

The Regional Gas Grids scenario spreads the burden of physical infrastructure across both methane and hydrogen, allowing for more gradual deployment in later years. However, delaying the start of the investment is unlikely to be possible as both the methane and hydrogen infrastructure projects are likely to compete for some common resources, like construction workers, and so opting to use both types of gas does not double the effective build out rate.

Early action is similar to the other scenarios, demonstration of both hydrogen and syngas technologies is assumed to proceed until around 2030.

As in the High Hydrogen scenario, key prerequisites for the scale demonstration of hydrogen include demonstrating the safety case, closing some technical evidence gaps and developing a funding mechanism to support large-scale demonstration work. Thereafter early deployment of hydrogen and syngas production begin to be rolled out. This will require the development of policy mechanisms capable of managing policy risk for potential investors and may even require a support mechanism in place to subsidise the first wave of investment.

An accelerated period of conversions and construction occurs from 2040-2050. It is assumed that commercial projects are operational before this date, provide practical evidence and comfort for subsequent investors in the sector.

Where are the interdependencies?

Coordination requirements are in line with those discussed for High Hydrogen and Methane Peaking. Changes need to occur in a coordinated way across the value chain to enable the hydrogen conversions, and simultaneous switching will drive a need for coordination. Coordination with other sectors will also be crucial: CCS is required for this scenario, and coordination with the electricity sector will be important to enable the use of fuel cells and hybrid heat pumps.

Are there key decision points?

Given the lead times, sequencing and optionality requirements for a hydrogen or low carbon methane roll out, decisions to begin incremental roll out of hydrogen investments across the value chain may need to be taken in the mid to late 2020s. Again, the strategy could be adjusted as new information comes through over the next decades- that is hydrogen conversion could be curtailed or expanded.

Although the Regional Gas Grids scenario effectively entails the pursuit of multiple scenarios, again, after 2030, the scale of investments in the hydrogen supply chain implies the need to decide whether or not hydrogen is going to be used in the 2050 end state or not. As such, there is limited scope to genuinely pursue multiple paths at reasonable cost beyond this point, when construction of upstream hydrogen production capacity and the hydrogen transmission system begin in earnest.

How might consumers be impacted?

As well as the issues discussed around choice, costs and heating quality in the Methane Peaking and High Hydrogen scenarios, this scenario will also involve local differences in energy systems. This means that the costs of providing gas to consumers is likely to vary by region, as well as over time. The functionality of heating systems may also vary.

What are the key areas of uncertainty?

The scenario is more exposed to technology uncertainty than the other two scenarios – both CCS and the mass deployment of syngas production are required. Though using multiple technologies might imply some diversification benefit, in practice it would be difficult to respond to material problems with CCS by increased focus on low carbon methane technologies given the feedstock constraints on sustainable gas supply. As with the High Hydrogen scenario, the decisions on building hydrogen transmission infrastructure are associated with the largest stranding risk (a half-built pipeline has effectively no residual value and the transmission investments are inherently very lumpy).

8.2 Approaches for the transition

Each low carbon gas system scenario poses specific challenges in the transition. However across these scenarios, three particularly significant themes set this transition apart from other major changes that have been implemented in the UK.

- **Uncertainty and keeping options open** – There is a large degree of uncertainty over which is the best scenario to pursue, given limited information on the future relative costs of technologies, their feasibility and consumer preferences, as well as the potential for disruptive technologies and unforeseen events.
- **Coordination requirements and policy risk** – While the degree and nature of required coordination varies across the scenarios, coordination will be an essential part of all scenarios[35]. Interdependences and the need for simultaneous switching mean that coordination across the gas value chain is particularly important where hydrogen is being rolled out. However, increased coordination between the gas, electricity and district heat sectors are important in all scenarios. The fact that the transition is driven by the need to mitigate against climate change, also means investors face significant policy risk, including a much greater risk of assets being stranded, absent a clear policy direction.
- **Consumer experience and protection** – In all scenarios, the set of technologies consumers can choose from changes, with consequences for the cost and quality of the heating service and the disruption faced by consumers. Consumer experience may also vary by area and over time, and vulnerable consumers may need additional protection.

While the scale of the investment described for each scenario is not necessarily a reason to intervene in itself, it magnifies all of the challenges associated with the transition.

In the rest of this section we discuss potential approaches that could enable the transition related to each of these themes.

[35] We note that either markets or the public sector have the potential to drive this coordination, depending on the situation.

8.2.1 Uncertainty and keeping options open

Broadly speaking there are two types of actions that could be taken to help decision making in the face of uncertainty.

- **Investing in keeping options open –** This would involve either actively trying to keep multiple options open or encouraging investments that are robust to a broad range of outcomes.
- **Investing in information** – Investing to keep options open provides optionality, but doesn't imply that this optionality is used to best effect. Therefore, in addition to investing to keep options open, it makes sense to invest in gathering the information needed to support decisions on when it does or does not makes sense to close down or pursue specific outcomes.

Investing in keeping options open

The Government can maximise its flexibility by deferring decisions and by supporting multi-use investments, which remain valuable under a variety of outcomes.

The value of **deferral** comes from back-loading capital-intensive investments (such as networks and upstream production facilities) so that investors can benefit from future information.

Deferral is not costless. In particular, it shortens the time available between now and 2050, requiring more rapid deployment to meet the 2050 target. It therefore may increase the costs of that deployment. The potential for higher costs need to be weighed against the potential benefit of taking a more informed decision later on.

In the High Hydrogen and Regional Gas Grids scenarios, a back-loaded rollout strategy could be used to allow some investment to proceed, while deferring major sunk costs in networks and end use conversions. For example, this could be based on developing a relatively low-cost initial anchor load for hydrogen demand, targeting sources of demand needing only relatively small additional investments. Potential approaches for realising such back-loaded deployment include targeting:

- fleet transport networks, where end-use asset lifetimes may be low and supply by road-based tankers is likely to be an option;
- clusters of industrial demand, where the network topography means they can be switched comparatively easily and production can be established nearby; and
- customers using bottled LPG, where again road transport is an option and there is already some space for local storage.

Establishing an anchor demand for upstream production could facilitate technical and commercial learning upstream while delaying the need to sink capital into networks and end use conversions. On top of the general costs of deferral mentioned above, there are also likely to be a set of specific challenges. Establishing a hydrogen fuelling system for a bus network, for example, imposes various technical constraints, including the need to locate hydrogen storage close to where the buses operate, storage that may later be stranded. Converting industrial demand may actually result in higher industrial emissions if the initial source of hydrogen is unabated and would also require very close cooperation with the relevant industrial users. These users may well need to be subsidised, at least initially, which could have knock-on impacts on competitiveness in their product markets.

In all three scenarios, it may also be possible to defer upstream investment by relying more on imports. Cons from this approach include potentially funding investment overseas (rather than domestically) and failing to generate useful learning at home (though if investment is being driven by the UK, at least some of the learning should be transferrable). There is also a risk that overseas production crowds out domestic investment in the long term, which may be an issue if there is a value in having domestic sources of hydrogen or low carbon methane for security of supply reasons.

Another approach would be to apply phased environmental or sustainability standards for upstream producers that reduced the cost of initial investments. For example, in High Hydrogen and Regional Gas Grids, early SMR investors might not have to use CCS. In Methane Peaking and Regional Gas Grids, early syngas producers could be allowed to use feedstock supply chains that might not be deemed acceptable by 2050 in terms of their sustainability. In both cases, the potential benefit to deferring any costs would have to be weighed against the associated environmental cost, as well as the potentially higher long term costs of this strategy.

An alternative approach for increasing flexibility is to actively pursue **multi-use investments** that are robust to a range of outcomes even where these investments are more expensive than their less flexible counterparts. Projects that are flexible in terms of their output or their market are at lower risk of becoming stranded and are not tied to the timing of a decision on the future of heat. This has the benefit that deployment can begin sooner (and potentially with less support from Government), which in turn provides earlier learning to help inform decision making and allows for a slower (and potentially less costly) rollout of production capacity.

An important example of a multi-use investment would be the use of so-called hydrogen-ready boilers that could easily be switched from using natural gas to using hydrogen. Such appliances could increase optionality in the High Hydrogen and Regional Gas Grid scenarios. In addition, since they would not become stranded in a hydrogen conversion scenario; they would also greatly simplify the conversion process, giving consumers far greater choice on when to switch appliances and necessitating far less coordination between end users and any conversion delivery body (though we note that home visits at the time of conversion may still be required).

Dual fuel vehicles are also available[36]. These could also help in the transition, as use of hydrogen in vehicles could potentially begin before the full network of filling stations is in place.

The concept of mixed-use investments is also relevant to upstream production projects that are mixed in terms of either their potential output or output market. For example, syngas technologies can produce either methane or hydrogen, and

[36] For example hydrogen-diesel commercial vehicles: http://ulemco.com/

projects that can produce either would be potentially valuable in any scenario in which we do not fully electrify demand. Similarly, hydrogen production that can be used not just to meet heating demand, but also as a means to store excess energy from renewable generation, or to power transport projects or to sell overseas is inherently more flexible. Output flexibility for hydrogen production projects could similarly be supported by regulatory interventions to allow for the blending of hydrogen into mains gas, providing it a potential roll even in the absence of a full hydrogen conversion.

These approaches are summarised in Figure 45 below.

Figure 45 Issue: the value in keeping options open

Approaches	Pros	Cons
Options for deferral: • focussing on anchor load such as fleet transport networks, industry or customers using bottled LPG • delaying the application of emissions constraints • relying on imports in the short term.	Backloads costly investment until greater information is available, to reduce the risk of stranding	May increase long run costs if temporary investment is required which is later stranded Shortens the time available for the transition and may involve diverging from the most cost-effective investment path (for example requiring higher intensity, and therefore potentially more costly investment at a later stage)
Pursue multi-use investments, for example hydrogen ready boilers and syngas plants that can produce low carbon methane or hydrogen	Allows greater flexibility to change strategy as more information comes in	Higher upfront costs

Source: Frontier Economics

Investing in information

As noted above, keeping options open provides a degree of flexibility, but ultimately the value of that flexibility is only fully realised by taking better decisions. To realise that value, it therefore makes sense to invest in information in a way that supports effective decision-making.

Industry can play a major role in this investment. However, there is therefore a trade-off between setting the direction early, and potentially securing greater private innovation spending, and keeping options open, but needing to spend more on publically funded research.

Potential approaches for such investment include direct efforts to demonstrate technologies and to fund R&D and pilots. For example Ofgem's Network Innovation Competitions are already driving innovation in the low carbon gas space. There is also a potentially important role for establishing the UK and international groups needed to help ensure that the right research gets done and that information is gathered and disseminated as required (see Box 8).

BOX 8: COOPERATION ON INTERNATIONAL RESEARCH

Internationally, there are two important drivers for cooperation. First, for some topics, research in a specific country is likely to have a value beyond that nation's borders. The UK has higher levels of piped gas and lower levels of district heat than many other European countries and our research priorities will therefore be different, but the use of hydrogen and CCS are still of wider interest. By sharing information and, where appropriate, splitting the costs of research, more cost-effective projects can be identified and wasteful duplication can be avoided. This increases the cost-effectiveness of public funding, albeit at the cost of reducing UK government control. However, we note that some research will need to be focussed on the particular conditions of the UK and cannot benefit from this effect – for example, research on the storage element of CCS, and its impact on long term liabilities. Second, there are strategic considerations that may hinder research progress in absence of international coordination. To better understand this consideration it's worth reflecting on the experience of Germany with respect to the development of solar PV. Germany invested heavily in this technology as part of an industrial strategy designed to make it a technology leader and support the creation of an associated domestic industry. However, after progress was made, the associated manufacturing base moved to low-cost centres in Asia undercutting any long-term economic gains. In the case of capital-intensive research projects on hydrogen, and linked to the discussion on the value of deferral above, the optimal strategy may instead be to wait and see, in the hopes that other nations will undertake the more speculative research projects at their own cost. Clearly if this strategy is widely used, the result will be a situation in which critical research is not undertaken in a timely manner and all nations bear the costs of inefficiently deferring decisions on the future of heat. This obvious coordination problem requires international cooperation to resolve.

Some research questions in particular will be pivotal to future decision making on heat, since their answers may effectively close down possible approaches to decarbonising heat. For example, answering questions on the feasibility of CCS and hydrogen storage and on the availability and sustainability of syngas feedstock will almost certainly be a prerequisite for taking appropriate decisions on the future of heat. As a result, identifying and pursuing such research areas are likely to be no regrets actions. It may also be useful to pursue questions in the social sciences (for example, around consumer acceptability) and also to undertake research which could demonstrate the economic fact base for subsequent commercial investment.

In addition to these, there are some associated questions that, while not ruling out options for 2050, significantly transform the optimal transition pathway by establishing different intermediate options or shedding light on the relative costs of different transition strategies. These would include, for example, consideration of the practicalities of a domestic hydrogen switchover and, in particular, the feasibility and cost of hydrogen-ready appliances. Again, these questions are fundamental to future decision-making.

8.2.2 Policy intervention

Policy intervention may be required to ensure coordinated investment is delivered in the transition. The degree and nature of required coordination varies across the scenarios, coordination will be an essential part of all scenarios. Interdependences and the need for simultaneous switching mean that coordination across the gas value chain is particularly important where hydrogen is being rolled out. However, increased coordination between the gas, electricity and district heat sectors is important in all scenarios.

Markets generally undertake coordination very effectively, with many participants interacting to produce and consume products across complex value chains. However, markets alone may not deliver the coordination required for the transition to a low carbon gas system. This is because of two major market failures:

- **Emissions externality.** The transition in this case is not being driven by consumer demand for better products, or supply side innovation, rather it is driven by the need to mitigate climate change. The climate externality means that to enter the market, investors across the value chain have to believe that there is long-term political will to tackle climate change. There are challenges to using carbon price signals to show this political will, linked to long-term credibility and distributional impacts. Therefore the transition is likely to involve a broad degree of government intervention.
- **Natural monopolies**. Gas and electricity networks are central to the delivery of low carbon gas. Since these are natural monopolies, regulatory intervention in these areas will continue to be needed. In addition, the difficulty in sending optimal price signals through the regulatory systems mean that individual consumers or individual localities may make decisions which are optimal for themselves, but are not optimal for GB as a whole (due to the wider costs these decisions place on the energy system).

Market failures therefore mean that markets alone are unlikely to deliver the coordinated investment required in the transition. In particular, a public body may need to take action in the following areas.

- **Decide on the strategy that is likely to be optimal for the UK (or a region within the UK) to pursue –** This does not necessarily mean fixing a gas sector-specific target for 2050. Rather it may include for example, deciding that it is worth pursuing the incremental roll out of hydrogen or hybrid heat pumps across the UK, with planned decision points where the strategy could be altered. Or a decision could be made that the optimal outcome is likely to involve more bottom-up locally-driven solutions. As described in Section 8.1, these decisions would need to by the late 2020s across all scenarios.
- **Set and apply a framework for achieving this strategy –** Setting a framework may involve sending long-term policy signals around the carbon externality (for example through contracts, price signals or regulation), and ensuring that planning decisions across different geographic areas, and different energy vectors are consistent and efficient. It could also involve ensuring national infrastructure (such as new hydrogen NTS) is planned in an efficient way.

Policy intervention could be driven from central government (which could unlock scale efficiencies and facilitate rational planning of national assets like a new hydrogen NTS) or at a more local level, for example via Local Authorities (which could benefit from a greater understanding of local issues, and potentially facilitate greater public acceptance).A mix of local and national coordination could be possible.

We now describe how Government could set and apply a framework for achieving a low carbon heat strategy. Action is likely to be particularly important in three areas.

- **Delivering investment in the presence of policy risk**. As described in Section 8.1, this is likely to be particularly important in the High Hydrogen and Regional Gas Grids scenarios, given the potential need for simultaneous switching and coordination across the value chain to deliver a hydrogen system, all in the presence of policy risk associated with the emissions externality. However, it is also potentially important in the Methane Peaking scenario: for example, investors in syngas plants may need to believe that Government will continue to value low carbon methane more highly than methane from fossil sources.
- **Managing the impact of stranding of existing assets.** Stranding of existing assets is likely to be an issues in all scenarios (Section 8.1), given the changes in the use of networks implied in the transition. Parts of the methane transmission network may be stranded in the transition to a hydrogen system, and parts of the methane distribution may be stranded under the increased electrification associated with Methane Peaking. Stranding of consumer assets may also be an issue in Regional Gas Grids and High Hydrogen. These are discussed in Section 8.2.3.
- **Coordinating between energy vectors.** As described in Section 8.1, this is likely to be particularly important in Methane Peaking and Regional Gas Grid scenarios, where end use technologies interact with both the gas and electricity systems.

Delivering investment in the presence of policy risk

The presence of the emissions externality and natural monopolies in networks means that some decisions affecting investment will ultimately rest with the Government. This does not necessarily imply the need for public delivery. However, it does mean that private investors are likely to be exposed to a significant degree of policy risk. Allocating these risks to the party that can manage them most effectively will be an important determinant of the feasibility and cost of securing private investment.

For example, the conversion to hydrogen in the High Hydrogen and Regional Gas Grids scenarios will require large capital investments in hydrogen production capacity. The returns to a potential investor in a SMR facility will depend on decisions about the drive to convert heat and transport end-users, the regulatory scope for the blending of hydrogen and methane and the regulatory and economic support given to future domestic methane production. Similarly, in Methane Peaking and Regional Gas Grids, the returns to an investor in a syngas plant will depend on government's commitment to promoting the use of low carbon methane, instead of the fossil-fuel alternative.

In this section we therefore consider the nature of the risks facing investors in both new and existing assets, and potential approaches that might be appropriate for dealing with them.

Large-scale investments in new assets are unlikely to take place before a clear and credible decision has been made on the long-term direction for the decarbonisation of heat. But even after this decision has been made, in the absence of contractual protection, potential investors may still be concerned by the threat of a future watering down of public commitments or a change of policy direction. There are limits to which the Government can credibly bind its hands to instil confidence in specific strategy.

Government could commit to directly delivering some of the investment (as is the case for example with Crossrail). This has the benefit of allowing greater predictability and control for policy-makers, and potentially allowing a lower cost of capital to be secured. However there are risks associated with this approach: private investors, facing market signals, may be better placed to manage wider risks associated, for example, with future commodity prices and construction costs. They are also likely to have greater experience in delivering major infrastructure projects.

Alternatively, delivery could be left to the market, once the coordinating body has set an appropriate carbon price and planning framework. This however, may not result in an efficient outcome, given the difficulties in setting a long term, credible carbon price and the fact that private investors are not best placed to manage the policy risks associated with the potential for a change in strategy.

There are also approaches which would transfer policy risk facing investors back to the decision-making body. This is likely to be an efficient solution, since the coordinating body that takes the decision is in full control of the relevant risk. It is exactly the rationale for the change of law clauses in public contracts, which protect the contracting party from subsequent changes in policy, and transfer the risk back to the Government itself. One possible solution would be the use of an implementation agreement that covers investors in the event that explicit political outcomes occur or do not occur. The approach is inspired by the types of commercial arrangements used to attract infrastructure investment in emerging markets (Box 9).

BOX 9: IMPLEMENTATION AGREEMENTS

An implementation agreement would effectively act as a form of insurance for investors exposed to significant policy risk. As such, it could potentially be sold by the Government to interested investors. It would be designed to transfer risks within the Government's control back to the Government, where they can be managed directly. To understand how they would operate in practice, we describe an example for the case of an SMR plant. The relevant contract would provide the investor with an option to sell the plant to the Government in the event that certain explicit conditions pertained. The contract would set out the price the Government would be obliged to pay, probably formulaically, and the conditions under which the option could be exercised. These might include, for example, a failure to impose a specific regulated price of carbon for methane users, or the failure to hit certain regulatory milestones necessary for the blending of hydrogen into mains gas. The price at which the plant could be sold could be set so as to protect debt finance and a minimal level of equity return and therefore support relatively low-cost borrowing. The conditions under which the option to sell could be exercised could be set so that the Government retained effective control on whether or not the contracts would be exercised. Finally, the fact that the contract is structured as an option means that if the plant owner was able to make a reasonable return even in the event the Government failed to meet the specified conditions, it is unlikely that the contract would be triggered. Consequently, the Government would not be penalised for policy or regulatory changes that left the relevant investment commercially viable.

Other potential approaches would include the underwriting of third-party debt for major infrastructure works, similar to the Infrastructure and Projects Authority's Guarantee programme. However, these guarantees could, like the implementation agreements, be made conditional on the failure to meet political or regulatory commitments, ensuring that the Government does not take on excessive risk and is able to provide the guarantees at low cost. The main advantage of both these approaches is that policy risk is transferred back to the Government, ensuring the most efficient possible allocation of risk, since Government is most able to manage that risk.

It is worth noting that though these approaches are well-targeted mechanisms for dealing with the policy risks facing new investment, they may nevertheless be insufficient to trigger commercial investment where the relevant investments face significant other risks, such as the risk of technological change, or the risk of import competition. Where these risks are so significant as to preclude commercial investment at the pace required by the transition, it is conceivable that further interventions, or contracts that transfer a greater proportion of risk to taxpayers or consumers, may be required to bring forward investment.

There is already considerable precedent on how government intervention can bring forward private investments through, for example, cap and floor regimes, like that for interconnectors, or CfDs, like those for low carbon generators. There are many options for the design of such mechanisms that go beyond the specific examples currently in use in the electricity sector. For example, auctioning could be brought into a cap and floor process to maximise price discovery, while banding around the price received could be brought into a CfD design. Generally, cap and floor- type mechanisms may also be better suited to infrastructure investments like SMR plants on the assumption that they sell the associated conversion process through tolling agreements, rather than the actual commodity, hydrogen. This is because cap and floor mechanisms focus on banding the return investors can gain on their infrastructure investment. In the case that the gas production plant owners were directly involved in the hydrogen market, a CfD-type mechanism for hydrogen might be more relevant, since this is focussed on guaranteeing a price for the gas produced.

Figure 46 summarises these options.

Figure 46 Issue: Options for delivery of investment

Approach	Pro	Con
Private sector delivery, with policy risk transferred to taxpayers	Cost of capital should be at an efficient level, with investors managing the risks that they are best placed to manage.	
Private sector delivery with policy risk managed by investors		Higher cost of capital leads to higher costs of consumers. Potential that investment will not proceed at the pace required for the transition.
Further investment support (E.g. CfDs, cap and floor)	Government can increase the pace of roll out to meet the challenging timetable required to deliver the transition by 2050. As described in Section 7, consumers may gain from additional price stability.	Transfer of further risks to consumers or taxpayers may not be efficient, and may lead to higher costs.
Direct Government delivery	Coordination body can produce a plan that optimises the heating system for UK plc. Cost of capital for Government is likely to be lower.	Lack of market signals means that there is a risk that public investment programme will be less efficient than market driven outcome – e.g. with the possibility of overinvestment, gold plating etc. The market may also be more efficient and bringing in skills.

Source: Frontier Economics

Managing the impact of stranding existing assets

The transition is not just about building new assets, but also about ensuring the continued efficient management of those assets already in existence, notably the network and storage assets.

Most approaches for the decarbonisation of heat involve the stranding of some of these assets. For example, in High Hydrogen and Regional Gas Grids, part of the methane transmission network may be stranded. In Methane Peaking, there are stranding risks around parts of the methane distribution network.

The cost implications of stranding are subject to significant uncertainty[37] and the decommissioning process for assets is unknown. A coordinating body could make it clear whether investors will be fully exposed to the costs of stranding, in which case they may be discouraged from beneficial intermediate investments, or whether this risk might be borne by consumers or taxpayers, with potential negative impacts on investor incentives to manage their assets efficiently.

We have previously recommended, as part of our work for the CCC, that Ofgem seek to set out an approach for the treatment of stranding costs as part of the next gas distribution price control. It is likely that this approach will seek to shield investors from stranding costs that arise for reasons beyond their control and for which there is little or no advanced warning. In these cases, the regulator may wish to provide a credible guarantee that the asset owner will be compensated, with the costs socialised across all network users or via the tax system. Where it is deemed appropriate for the stranding risk to be shared with consumers, this could be achieved by accelerating the rate of recovery allowed in the price control. Conversely, where new risks arise, but they are deemed to sit with the asset's shareholders, provision may have to be made for this in the assumed WACC. Setting out an approach for dealing with asset stranding should help to clarify investors' incentives as the risks of stranding become more material over time.

Coordination across energy vectors

One of the conclusions from looking at a range of scenarios for the decarbonisation of heat is the need for greater coordination across the affected fuel vectors.[38] Specifically, there is a need for:

- coordinated planning, to ensure efficient investment across the gas, electricity and heat vectors (in all scenarios); and
- greater operational coordination, if end-use heating and distributed generation technologies, as well as the possible use of electrolysis, lead to greater operational interactions between the use of gas and power (particularly in Methane Peaking and Regional Gas Grids).

With regards to coordinated planning, because multiple fuel vectors could potentially be used to supply heat, there are fairly direct trade-offs between investing in the networks and production capacity required to support electrification, versus the equivalent investments required to support methane or hydrogen. There may also be trade-offs between the use of waste heat, or with the creation of heat networks. Efficient investment, which avoids duplication across multiple vectors or else results in delays to necessary investment, requires that

[37] There may even be instances where gas networks have residual value, for example as a means to run cabling.

[38] This conclusion is shared by the recent IET and the Energy Systems Catapult in their phase two Future Power System Architecture project report.

planning and investment signals are properly coordinated across all the affected vectors.

In practice, achieving this coordination is likely to mean that, for regulated network investments, gas, electricity and heat networks are using consistent planning assumptions and that the incentives and uncertainty mechanisms applied across these different networks are consistent and complementary. We summarise potential approaches in Figure 47, and discuss them in more detail below.

Figure 47 Issue: Coordination planning between energy vectors

Approach	Pro	Con
Shorten price control periods	Allows closer alignment of planning assumptions.	Reduces the focus on longer term thinking in investment decisions, which was Ofgem's original rationale for longer price controls[39].
Align price control periods	Allows consistent information and assumptions be used in planning.	Increases peaks and troughs in terms of pressure on the regulator's resources.
Regulatory incentives to encourage networks to invest efficiently in other networks	In theory could achieve an optimal outcome across vectors.	Difficult to implement in practice.
Requirement for cross vector consultation as part of well-justified business plans	Light tough and easy to implement.	May have limited effectiveness.

Source: Frontier Economics

Practical suggestions to help achieve this include the shortening of price control periods, to facilitate the closer alignment of planning assumptions. This has the added benefit of facilitating faster adjustments to new information (for example on the costs and feasibility of different decarbonisation strategies). The alignment of price control periods across electricity and gas, would similarly enable consistency of assumptions (although might not be necessary to achieve this end). While this would require a licence modification, this would be straightforward in the context of undertaking a price control review. In addition, a requirement that business plans are created in collaboration with the other relevant networks could be introduced, though without additional regulatory measures, this could have limited impact.

It was also suggested that regulatory incentives might be created that encourage the networks to invest efficiently across both the gas and electricity networks, for example by rewarding an electricity network that identifies a more cost-effective solution to a problem using gas network investment. In practice however, it is likely to be very difficult to create effective incentives to encourage such behaviour while the networks remain under separate ownership.

On the need for operational coordination, the scenarios we have considered include the use of heating technologies that can use either gas or electricity (hybrid

[39] https://www.ofgem.gov.uk/sites/default/files/docs/2010/10/decision-doc_0.pdf

heat pumps), or for the widespread use of gas for distributed power generation (fuel cells or micro-CHP).

At this stage, the main issues for Government to consider in relation to operational coordination are likely to be around aligning tax and policy costs, metering and the potential for greater coordination between the gas and electricity system operators (Figure 48).

Figure 48 Issue: Operational coordination between energy vectors

Approach	Pros	Cons
Align tax and policy costs across heat, gas and electricity	Facilitate efficient fuel switching.	Potential for negative impacts on wellbeing (since more customers use gas for heating).
Ensure decisions on metering support consistent signalling across vectors	Facilitate efficient price signals.	Additional costs to ensure functionality is aligned.
Coordination between gas and electricity System Operators	Allow management of complex flows between networks.	These entities are currently separate, due to a perceived risk of gaming.
Set up processes to enable faster and more coordinated changing of codes	Facilitate timely and coordinated changes.	Administration costs Faster processes may result in less optimal decisions.

Source: Frontier Economics

In this context, it will be particularly important that the price signals (including taxes and policy costs) on which these decisions are made are accurate and consistent across the fuels so as to avoid perverse behaviour. Poor price signals at the consumer level may well lead to inefficient behaviours. At present, policy costs are disproportionately recovered from electricity bills. It will be important to consider reforming this, particularly where fuel switching for heating between gas and electricity becomes more feasible for domestic customers. We discuss this more in Section 8.2.3 below.

Changes to metering can be costly and require long lead times and so it is worth consideration even now that decisions on metering will support consistent signalling across the different energy vectors in future. This should help avoid a situation where, for example, it is not possible to meter both fuels over consistent time periods.

With respect to system operation, we note that the Utilities Act currently prevents the gas and electricity system operators from close cooperation for fear that this might allow National Grid to game operational decisions to its advantage. Provided that the system operators can base their decisions on independently observable market conditions, such as the relative price of different heating options, there may be no need to change the current regulations. However, where more complex flows or higher loads on either network imply the need for one or other system operator to take additional unobserved network actions that impact the other operator, it may be necessary to revisit whether scope for greater collaboration is desirable.

It may also be necessary to more closely align the industry codes governing different fuel vectors in order to ensure that even decentralised operations work in unison. As the IET and Energy Catapult's recent work on the Future Power System Architecture makes clear,[40] changes to the current network codes may not be possible given the existing industry governance processes. In particular, these processes are unlikely to be sufficiently agile given the expected pace of change, with even minor changes requiring months or even years to implement. They are also unable to deal with issues that range beyond the relatively narrow membership of the relevant governance processes. At present, the arrangements are segmented across the supply chain and lack a remit to consider wider issues. In light of these problems, the Government may wish to establish mechanisms capable of realising code changes in response to issues that span multiple energy vectors and multiple existing governance processes. Ofgem is already exploring some of these issues following the CMA recommendation on code governance[41].

8.2.3 Consumer experience and protection

The transition to a low carbon gas grid, and particularly to low carbon heating, would have a major impact on consumers, given the number of households that need to switch end use technology. This impact would depend on how the new technologies differ from the incumbent technologies, how these differences are perceived by consumers, and on the way in which the transition is managed.

- **The set of technologies consumers will be able to choose from would change** – The ease of transition, and the interventions required to assist it, will depend on consumers' views on whether the changes are positive or negative. These differences span many features:
  - Functionality – The technologies may be more complex (for example in the case of hybrid heat pumps, fuel cells and micro-CHP), provide a different quality of heating service, or deliver increased functionality that consumers value.
  - Upfront cost – Any increase in the upfront cost of a technology (even if ongoing running costs are lower) is likely to be met with resistance.
  - Ongoing cost (and its volatility) – As well as the upfront cost, consumers will be conscious of any increase in running costs that follows a change in technology. There may also be differences in the volatility of prices faced by customers over time depending on the input energy source and the mix of upfront to ongoing costs.
  - Disruption of changeover – Some solutions will require more change to be made within people's homes (for example a need to change the radiator system or to install insulation).

  Differences that are perceived as negative will make the transition harder. It is possible that innovation could drive a better product at a lower price, making

[40] See, for example, the Future Power System Architecture Project 2 Policy Briefing Paper available at: http://www.theiet.org/sectors/energy/resources/fpsa/fpsa-future-system-challenges.cfm.

[41] Ofgem (2017), *Update on the implementation of the code governance remedies.* https://www.ofgem.gov.uk/system/files/docs/2017/07/update_on_the_implementation_of_the_code_governance_remedies.pdf

the transition easier. However, given that consumers are generally happy with the incumbent gas boiler technology, this may be less likely..

- **Regional differences emerge** – In Regional Gas Grids, different regional solutions emerge. Therefore any differences between the set of technologies that remain after the transition, may also be important.
- **Temporal differences emerge** – Even if everyone ends up on the same technology, differences may emerge because the roll out takes place incrementally, with those switching earlier potentially incurring higher costs. For example NEA research has found that those converting first to low carbon heating could pay between £4-16k more over the whole period to 2050, than those converting at the end of the period.[42]
- **There may be stranding of consumer assets** – Since the switch from methane to hydrogen in High Hydrogen and Regional Gas Grids needs to happen simultaneously across an area, there is a risk that consumers' existing methane assets will be stranded before the end of their lives if they cannot work with the alternative fuel (discussed below).

In this section, we look at some of the transitional policy options that may be needed to motivate and protect consumers during the transition. Certain policy goals, such as reducing fuel poverty or promoting competition, are likely to remain whatever the transition path (although the level of intervention required may differ). We therefore focus less on these existing policy questions[43], and instead consider the additional consumer issues that arise.

We now discuss options for measures to:

- impact on the costs faced by consumers;
- deliver public buy in;
- manage the costs of stranded assets; and
- make take-up mandatory.

Measures to impact on consumer costs

A variety of policies focussed on cost can be used to affect the incentive of consumers to transition to new technologies, and manage regional and temporal inequities. The pros and cons of measures to affect costs are set out in (Figure 49).

[42] NEA (2017), *Heat Decarbonisation: Potential impacts on social equity and fuel poverty*. http://www.nea.org.uk/resources/publications-and-resources/heat-decarbonisation-potential-impacts-social-equity-fuel-poverty/

Figure 49 Issue: Consumer costs in the transition

Approach	Pros	Cons
Levy a carbon price on emissions from gas use in line with marginal costs of meeting the GHG target	Efficient incentive for use of low carbon gas Could reduce regional and temporal inequities during the transition.	Impact on gas prices could have negative impacts on health and wellbeing – particularly for the fuel poor.
Upfront technology subsidy- in line with carbon price	May be effective, given consumers' focus on nearer term costs and benefits in their purchasing decisions. Could result in an efficient outcome. Could reduce regional and temporal inequities.	Cost to Government. May not result in efficient use of fossil fuel gas.
Ongoing fuel subsidy - in line with carbon price	Could result in efficient take up and use of low carbon technologies. Could reduce regional and temporal inequities.	May be less effective than an upfront subsidy, given consumers' focus on nearer term costs and benefits.

Source: Frontier Economics

Discussions around these options are well rehearsed. However there are some interesting questions around how the recovery of costs associated with the transition could affect consumers. In the discussion below we consider how three types of costs could be recovered.

- **Energy system costs resulting from an individual consumer's choice** – An example here could be the system costs resulting from a consumer's choice to take up and use a heat pump instead of connecting to an available low carbon gas grid.
- **Energy system costs resulting from the cost of enabling all consumers in a given region to access low carbon gas** – An example here could be the costs associated with building a new hydrogen NTS.
- **The costs of subsidising early adopters –** An example here could be the costs of subsidising upfront or ongoing costs for households who switch to hybrid heat pumps early in the transition.

To help ensure an efficient outcome, it will be important that consumers face the whole system costs of their decisions, where their decisions can impact on these costs. For example, if an individual consumer on the hydrogen grid wishes to choose a heat pump instead of taking up a hydrogen connection, it will be important that that consumer faces the full electricity and gas system costs of that decision for an efficient outcome to be delivered. This would mean, for example, that the costs of electricity network upgrades required to connect that heat pump should be borne by the consumer.

On the other hand, where consumer decisions cannot influence costs, it may be more appropriate to socialise these costs. For example, any individual consumer decision won't influence the overall costs associated with constructing a hydrogen

NTS in the High Hydrogen scenario. Therefore it may be both efficient and equitable to spread these investment costs across all consumers on the hydrogen network. However if consumers on the hydrogen network are paying more than those on methane networks, (and assuming that this outcome is driven by the decarbonisation strategy that is most cost-effective for the UK as a whole) it may make sense to spread the NTS costs over all energy users, to help manage regional inequities. This could be achieved by levying a charge on bills for all energy users, including those who are not connected to the hydrogen system. While this would also rebalance the costs of different fuels, it could embed cost differences in a manner that may ultimately turn out to be inappropriate, given the uncertainty over the relative price of low carbon gas in the transition (driven in part by uncertainty over the cost of processes like electrolysis).[44] This type of socialisation of cost could also be achieved by funding the NTS through the tax system. This may be less regressive, and could allow greater flexibility to changing costs over time. Similar arguments would apply to the cost of funding subsidies.

The pros and cons of potential approaches to recover costs in these areas are summarised in Figure 50.

[44] For example, a decision could be taken that the hydrogen NTS should be funded by all energy users on the basis that hydrogen was a more expensive option. If the cost of producing hydrogen were to subsequently fall, consumers who heat their homes with electricity would find that they were both paying for the higher cost fuel, as well as continuing to provide a subsidy to hydrogen consumers.

Figure 50 Issue: Need for cost recovery

Approach	System costs resulting from individual consumer's choice	System costs based on enabling a region to access low carbon gas	Costs of subsiding early adopters who bear higher costs
Household's individual network charges	Efficient and fair if households face full system costs of their choice.		
Network charges for all households on the low carbon grid	Could lead to inefficient consumer choices, and unfair costs to all consumers.	Likely to make sense from an equity point of view only if the low carbon option is cheaper than the incumbent option.	Could help overcome upfront costs and temporal inequities, but will not help manage regional inequities if the low carbon option is more expensive than the incumbent option.
Network charges for all households on gas and electricity grid		Could help manage regional and temporal inequities if low carbon option is more expensive.	
General taxation		Likely to make sense from an equity point of view if the low carbon option is more expensive than the incumbent option. Also less regressive and more flexible than network charging.	

Source: Frontier Economics

Public buy-in

Securing public support may pose the single biggest barrier to a successful transition across all scenarios. Without public support, the conversion of end use technologies may not happen and cross-party political support for the decarbonisation project may falter, thereby undermining the certainty and stability needed for effective delivery.

This is an area where precedents for successful intervention are few and thinking about the options available is comparatively undeveloped. Further, the transition itself will be a difficult "sell": many consumers are happy with their existing heating systems; some low carbon interventions will not make them better off, either financially or in terms of the heating service they receive; and potentially invasive action will be required in their homes to effect the transition.

This is not to say that it cannot be done, but merely to highlight that for a programme of this scale, with potentially significant interventions inside people's homes, the need to build public support goes beyond even examples like the digital switchover, the delivery of the Olympics or the construction of Crossrail.

Potential approaches for engendering public support include the following (Figure 51).

- **Create customer “pull” for the new technologies** – Innovation into low carbon heat technologies could help secure public buy in. Competition in the market for end use technologies may be particularly important for delivering improvements in aspects of the technology such as aesthetics and functionality. This argues towards ensuring that any subsidies in place on end use technologies are technology and model neutral. It also argues against roll out options that involve standardised models (such as fitting of a standard boiler by a network company as part of the network conversion).
- **National or local pride** – Linking the decarbonisation programme to a sense of national or local pride, following the example of Scotland’s strategy of seeking status as an international climate change leader could help.
- **Near term benefits** – Emphasising nearer term benefits such as the impact on air quality and health may make the benefits seem more tangible.
- **Measures to reduce disruption** – The disruption associated with the transition may prove to be as important a barrier to consumer acceptance as the relative attractiveness of the new technology. This disruption could result from the hassle associated with switching appliances in people’s homes (including retrofitting new insulation and radiators where required), as well as street works required to install new pipes or wires that could affect traffic and cause disturbance. Options to mitigate disruption include properly evaluating disruption impacts when making decisions, incentivising parties involved in the switchover to minimise disruption, and careful (co-ordinated) local planning of road works.

Although it may not engender public or cross-party support in its own right, it is worth mentioning the potential value of an Act of Parliament as a means of enshrining that support if and when it is achieved. In terms of the length of the transition and the scale of the challenge, there are clear parallels to the UK’s overall 2050 climate ambitions. These also cannot be achieved in the absence of cross-party political support. Unlike the Climate Act however, a decarbonisation programme for heat will relate more closely to issues of direct implementation, and therefore come with more tangible costs and practical difficulties. An Act of Parliament that is able to provide an expression of common purpose despite these issues and which can be referred to over the course of the decarbonisation programme might help all the parties involved stay the course and act as a useful motivator when things get difficult[45].

[45] The Scottish Government’s plans for a Climate Change Bill provide another example of this.

Figure 51 Issue: Need for public buy-in

Approach	Pros	Cons
Encourage innovation to find the added value for consumers associated with the new technologies	Improvements in products increase consumer welfare.	Results of innovation are uncertain.
Position UK or a specific region as a leader in this area	May engender national pride – for example Scottish drive for climate change mitigation.	Difficult to achieve. Some actions that are best for local areas may not be best for the UK as a whole (and vice versa).
Emphasise near term benefits such as impacts on air quality and health	These benefits may be more tangible for consumers.	Decarbonisation of the gas system may not be the most effective way of delivering these benefits.
Ensure disruption is minimised	Will not secure public buy in by itself, but reduces the risk of public disenchantment.	Cost.

Source: Frontier Economics

Action to manage the impact of stranding

There is a risk of stranding of consumers' existing technologies in the High Hydrogen and Regional Gas Grids scenarios, given the need to switch all consumers in a given area at once. Figure 52 describes some potential approaches for mitigating this risk.

Figure 52 Issue: Risk of asset stranding

Approach	Pros	Cons
Develop technologies that allow multiple input fuels (hydrogen ready boilers)	Reduce risk of asset stranding. Reduce the complexity of the work required at home visits (these may still be required for cookers and to prepare hydrogen-ready boilers for the switchover).	Not yet clear if these are feasible or cost-effective. Costs of R&D. Technology costs may be higher .
Second hand boiler market	Allows stranded boilers to be reused, and provides an option for short term solutions.	Safety issues may need to be resolved. Installation costs for short term solutions still need to be incurred – these make up a significant proportion of the total costs of purchasing a new boiler.
Alternative heating solutions in the short run	Helps avoid the cost of installing a new boiler.	Feasibility of electric solutions may be limited, given grid constraints.
Compensation	Manages costs of the transition for consumers.	Very high costs. Difficult to design an compensation scheme that is fair, and that doesn't provide perverse incentives to replace boilers.

Source: Frontier Economics

The first best solution will be to develop cost-effective technologies that can work with multiple input fuels, thus avoiding stranding risk. One way of delivering this certainty would be to make hydrogen readiness a required part of the standards for new boilers, in areas where a hydrogen network is planned. Alternatively consumers could be given clear information on when the switchover will occur sufficiently ahead of time, and left to choose whether or not to take up the hydrogen-ready option.

If hydrogen-ready boilers turn out to be too costly, or not feasible, the next best option would be to find a solution that will reduce the costs of stranding. Two types of option could help.

- A second-hand boiler market could be encouraged. At present, there is no significant second hand boiler market as consumers tend to keep their existing boilers until the end of the technology lifetime. The hydrogen switchover has the potential to increase both the supply of second hand boilers (as they are removed before the end of their lives), and the demand for them as consumers seek short term solutions when their existing boiler breaks in the months and years before a planned switchover. Given safety concerns associated with second hand boilers, this market may need to be appropriately regulated and also potentially delivered by "trusted" parties (such as local authorities, gas network companies or other licenced operators).

- To tide people over for very short periods of time (for example if their boiler breaks down in the months before the switch over), it may be most cost-effective to supply an alternative heating technology, such as electric heating, where grid capacity allows it. Bottled methane could also be useful to cover short term gaps in the transition.

If neither of these solutions prove possible, it may then be necessary to pay some compensation to consumers whose existing boilers need to be scrapped. This compensation could be delivered as a flat rate per household (which would mean that some people would be overcompensated, and some people undercompensated), or it could be linked to the remaining lifetime of the boiler (though care would need to be taken to ensure it didn't lead to an inefficient level of boiler replacement in advance of the switchover). Given this has the potential to be very expensive, it provides additional onus on working to find a solution to the first or second best options.

Mandating take-up

Mandating may have a role in the transition, particularly where existing effective regulations are in place or where there are barriers to applying price signals. In addition, it can also provide the supply chain with greater certainty, and in this way stimulate the development of innovative products and services (Figure 53).

Figure 53 Issue: Price signals cannot drive take up

Approach	Pros	Cons
Mandating take up of certain technologies	Provides an alternative where price signals would be ineffective. Ensures take up Provides certainty to investors .	Impacts on consumer choice. Potential for negative impact on consumer buy-in Risk of locking in suboptimal technology

Source: Frontier Economics

For example, the construction industry is used to complying with building regulations in the construction and renovation of properties. Expanding on these regulations to ensure properties are hydrogen- or heat pump-ready may be a more practical option than designing complex price signals.

Mandating may have a role where consumers are not likely to respond to price signals. This may be the case where a technology has lower lifetime costs, but consumers may be put off by higher upfront costs (for example some types of insulation or hydrogen-ready boilers). Mandating is, by its nature, good at delivering the transition at low cost to the tax payer. However, if mandating were to put the cost of the transition on individual consumers, consideration would need to be given to the affordability of the enforced change that is being required. It may therefore need to be accompanied by subsidies for certain consumers. Removing choice from consumers may also have a negative impact on consumers buy in to the transition – particularly where they are being compelled to take up a higher cost option.

There will also be a requirement for additional checks, balances and help during any compulsory switchover of technologies to ensure that no one is left without a viable means of heating their homes. An inventory of all properties and occupants may be necessary to provide the information to facilitate this process, alongside a programme of additional help for vulnerable consumers to help them to manage the process.

8.3 Summary

This section has described how a transition to a low carbon gas system would require a radical transformation of technology and infrastructure across the value chain. Action would likely to be required to manage this transition, particularly in three areas:

- **Uncertainty and keeping options open** – There is a large degree of uncertainty over which is the best scenario to pursue, given limited information on the feasibility of some key technologies, future relative costs and consumer preferences, as well as the potential for disruptive technologies and unforeseen events. Approaches for managing this uncertainty fall in two main areas: investing in keeping options open and investing in information. There is also a trade-off between the benefit of keeping options open and the cost of perpetuating uncertainty and requiring a faster build rate as the 2050 target approaches.
- **Coordination and policy risk** – While markets are generally good at delivering coordination across complex value chains, major market failures in this area mean that decisions that are best for an individual or locality may not be best for the UK as a whole. Government intervention to set a framework for the transition is therefore likely to be useful. There could therefore be a role for Government intervention to set a framework for the transition. There are range options for the extent of actions in this area, with trade-offs between the increased certainty around a publicly coordinated programme and the efficiency that markets might bring to this delivery.
- **Consumer experience and protection –** The success of decarbonisation relies on public support. Potential approaches for protecting consumers include measures to impact on consumer costs, including managing the costs of stranded assets, measures specifically aimed at delivering public buy-in and measures to require take up. While financial incentives or compensation may have a role in some cases, there are a range of alternative options which could also be explored. For example hydrogen-ready boilers or a second hand boiler market could help manage the impact of asset stranding.

9 CONCLUSIONS

This report aims to objectively describe challenges likely to be associated with a low carbon gas system and to present a wide range of strategies for overcoming these challenges.

We now summarise the analysis in the following areas:

- the 2050 scenarios;
- the 2050 market models; and
- the challenges in the transition.

We considered three low carbon gas system scenarios for 2050 in this work. These scenarios were developed specifically to stimulate and test thinking on the appropriate market and regulatory models for a low carbon gas system in 2050. While they have been designed to be technically feasible and internally consistent, they do not reflect an attempt to forecast the most likely or most desirable 2050 outcomes.

- **Methane Peaking** describes a system where hydrogen is not available and where the cost of producing low carbon methane (both nationally and internationally) rises sharply as production increases.[46] The resultant scarcity of low cost low carbon gas means that its use in the energy system is focussed on supplying high-temperature industrial processes, where few low carbon substitutes are available, and for meeting peak heat demand via hybrid heat pumps.
- **High Hydrogen** involves the conversion of all gas supply to hydrogen. In addition most of road transport switches to use electric vehicles powered by hydrogen fuel cells (alongside some use of plug in electric vehicles), significantly increasing total national demand for gas. Overall, transport demand makes up almost a third of total hydrogen demand under the scenario. End use in buildings is predominantly made up of the use of hydrogen boilers that are not dissimilar to today's gas boilers.
- **Regional Gas Grids** involves the separation of the existing national grid into a multiple separate pipeline grids. About 70% of total gas demand met from hydrogen; the rest is met by low carbon methane. Buildings end-use remains similar to today, with methane or hydrogen boilers used to heat water and provide space heating. The electrification of transport creates localised grid reinforcement issues, which creates new demand for the deployment of distributed electricity generation using fuel cells or micro-CHP.

2050 market models

The models developed in this project describe the market conditions and regulatory structures that could emerge in response to different scenarios for the decarbonisation of the gas system in 2050. Looking across the whole value chain, from upstream production to consumption, they set out how markets could operate to meet the needs of consumers, investors and industry participants. They also

[46] Produced from waste or biomass via anaerobic digestion or syngas production plants.

describe the role of government and other regulatory stakeholders in providing different levels of market intervention, regulation and centralised coordination.

The overarching conclusion from this model development work is that none of the scenarios implies a radical reinvention of the market and regulatory structures currently in place. While significant regulatory changes may be required, for example to facilitate greater coordination between energy vectors, many aspects of the market and regulatory framework could remain similar to those in place today. Despite the technological transformation implied by the scenarios, in the 2050 steady state and under the assumptions made in our scenario the gas system is similar to today with respect to its fundamental features.

Section 7 highlighted some of the overarching insights from the model development work.

- **Upstream production could be built around a competitive commodity market**
  - The scale of gas production plants is relatively modest (for example, around 500 MW for SMR units) The capital required for low carbon gas production facilities may be smaller than that required for natural gas production today, potentially reducing the barriers to entry for gas production.
  - All of our scenarios include many production facilities (domestically and potentially overseas) producing homogenous products. In High Hydrogen, over 80 SMR plants compete with multiple electrolysis plants and imports on the production of hydrogen. In Methane Peaking, hundreds of AD and syngas plants compete with imports. In these two scenarios, the gas that is produced is homogenous and can be traded in a competitive commodity market. Even in Regional Gas Grids, where imports play a smaller role, and two separate markets exist for hydrogen and low carbon methane, the number and scale of plants on the production side in each market imply competition would be possible.
- **Pipeline gas networks could remain regulated natural monopolies** – The role for the pipeline networks remains largely the same as today across all three scenarios. These assets retain the characteristics of natural monopolies in a low carbon gas system (high fixed costs), so they require a degree of regulation to ensure that they are efficiently used. While changes to the detailed codes would be required, regulatory arrangements similar to those currently in use should be able to incentivise efficient network use and bring forward any necessary investment, enabling the networks to efficiently carry out the functions required of them under all of the scenarios.
- **Storage should be able to operate competitively, although some intervention may be desirable for security of supply reasons** – Although the precise profile of gas demand will change, storage as a service will not differ markedly from what we see today. There will be multiple providers and the business will be similarly capital-intensive. As such, it should be possible for this service to be competitively traded among market participants. The only potentially significant driver of additional intervention would be concern over national security of supply. Concerns about security of supply may be more acute where low carbon gas also serves the transport sector.

- **Changes in end demand may stimulate the creation of new retail propositions** – This is particularly likely to be the case where end use technologies span both gas and electricity (as they do with hybrid heat pumps, fuel cells and micro-CHP in the Methane Peaking and Regional Gas Grid scenarios). In such cases, optimising the decisions of these consumer units is likely to be complex, but also to represent an opportunity for greater system efficiency. Energy suppliers might develop retail services that try to capture some of this value by, for example, offering lower cost energy services in exchange for the control necessary to optimise the consumer unit's operation.
- **Greater coordination across the gas and electricity sectors may be desirable** – The end use technologies used in the Methane Peaking and Regional Gas Grid scenarios (hybrid heat pumps, fuel cells and micro-CHP), which span the gas and electricity networks, will lead to greater interaction between the two markets and may unlock potential efficiencies, like new mechanisms for network congestion management. Given this, it is likely that the system operator of either network will, at the very least, want to be more aware of what is happening with the other fuel, in order to understand the patterns of demand it observes on its own network. It may also benefit from the greater coordination of system operation decisions across networks. This need for greater coordination may require significant regulatory changes.
- **The gas transport system may be more complex** – Alongside natural monopoly pipelines, all the scenarios also envision the potential transport of gas by road – either to accommodate distributed low carbon methane production (in Methane Peaking and Regional Gas Grids) or to supply off-grid hydrogen filling stations (in High Hydrogen). The scenarios also suggest the possible need for an expanded system operator role for the distribution networks, particularly where they must deal with significant levels of injection onto their networks (for example, from distributed AD plants in the Methane Peaking and Regional Gas Grids scenarios and from electrolysis plants in the High Hydrogen scenario).

Challenges in the transition

While market and regulatory models do not need to be fundamentally altered by 2050, the infrastructure and technologies used across the value chain will need to be radically transformed in the transition to a low carbon gas system. As described in Section 8, there are issues in the following areas:

- **Uncertainty and keeping options open** – There is a large degree of uncertainty over which is the best scenario to pursue, given limited information on the feasibility of some key technologies, future relative costs and consumer preferences, as well as the potential for disruptive technologies and unforeseen events. Options for managing this uncertainty fall into two main areas: investing in information and investing in keeping options open.
    - **Investing in information.** To keep options open, investment in demonstration will be required in the near term. To allow 2050 targets to be met, information on technology feasibility and cost will need to be collected by the late 2020s. This is particularly important where hydrogen plays a role (in High Hydrogen and Regional Gas Grids) since further work

on the technical evidence gap and safety case, as well as an end to end demonstration (including CCS), will be required before roll out begins. There is also a need to further demonstrate hybrid heat pumps and syngas production plants if the Methane Peaking scenario is to be pursued.

 - **Investing in keeping options open.** Whichever scenario is being pursued, roll out of capital investment is required from 2030. To some extent, incremental roll out (with the possibility of changing strategy if new information comes in after 2030) is possible in all scenarios. However, changing strategy is likely to be the most difficult and costly if High Hydrogen is being pursued, since the transition to this scenario involves coordinated changes across the value chain, and the need to construct a new national hydrogen NTS. There is also of course a trade-off between the benefit of keeping options open and the cost of perpetuating uncertainty, particularly in terms of the impact this may have on investment.

- **Coordination requirements and policy risk** – There are a large number of interdependencies involved in the transition to all of the scenarios. While markets are generally good at dealing with interdependencies and delivering coordination across complex value chains, market failures in the transition to a low carbon gas grid mean that there is likely to be an important role for Government intervention. In particular, the transition will be driven by the need to mitigate climate change. This means investors across the value chain have to believe that there is long-term political will to tackle the emissions externality and decarbonise the gas sector.

  - **Coordination framework.** Interdependences and the need for simultaneous switching mean that coordination is likely to be particularly important where hydrogen is being rolled out (in the High Hydrogen and Regional Gas Grids scenarios). At a minimum this is likely to involve deciding on the strategy that is likely to be optimal for the UK (or a region within the UK) to pursue. Setting a framework for achieving this strategy may involve sending long-term policy signals around the carbon externality (for example through contracts, price signals or regulation), and ensuring that planning decisions across different geographic areas, and different energy vectors are consistent and efficient. It could also involve ensuring national infrastructure (such as a new hydrogen NTS) is planned in an efficient way.

  - **Coordination between energy vectors.** Increased coordination between the gas, electricity and district heat sectors are important in all scenarios in the transition. In practice, achieving this coordination is likely to mean that, for regulated network investments, gas, electricity and heat networks are using consistent planning assumptions and that the incentives and uncertainty mechanisms applied across these different networks are consistent and complementary.

- **Dealing with policy risk.** The presence of the emissions externality and natural monopolies in networks means that some decisions affecting investment will ultimately rest with the Government. This means that private investors are likely to be exposed to a significant degree of policy risk. Allocating these risks to the party that can manage them most effectively will be an important determinant of the feasibility and cost of securing private investment in all scenarios. There are a range of options for allocating these risks, including implementation agreements, as well as more options for increased investor support such as CfDs and cap and floor.

- **Consumer experience and protection** – In all scenarios, the set of technologies consumers can choose from will change. Impacts on the functionality of heating are likely to be the greatest in Methane Peaking, where hybrid heat pumps are used. On the other hand, the transition to a hydrogen system, may require simultaneous switching, and service pipes within the home may need upgrading. Consumer experience may also vary by region and over time, and vulnerable consumers may need additional protection. The success of decarbonisation relies on public support, so the management of consumers' experience is crucial. Options for protecting and incentivising consumers include measures to impact on consumer costs (including the costs of stranded assets), measures specifically aimed at delivering public buy-in and measures to require take-up. While financial incentives or compensation may have a role in some cases, there are a range of alternative options which could also be explored. For example hydrogen-ready boilers or a second-hand boiler market could both help manage the impact of asset stranding.

ANNEX A INSTITUTIONS AND ENTITIES

This annex sets out tables for each of the scenarios in the following areas:

- significant risks and risk management options; and
- institutions and entities.

A.1 High hydrogen

A.1.1 Significant risks and management options

Figure 54 High hydrogen: major risks, issues and management options

Issue or risk	Market management options	Options for additional intervention	Notes
SMR and electrolysis plants may face volume risk (e.g. because of risk of cheap imports or alternative production technologies).	▪ Where this risk is fairly limited, production infrastructure could potentially be financed using standard merchant financing arrangements. ▪ Horizontal integration across hydrogen production/import infrastructure would help diversify commercial risk.	▪ Where commercial finance cannot be raised at reasonable cost, a cap and floor arrangement similar to that for interconnection assets could be used.	▪ The financing risk to hydrogen production is expected to be higher in this scenario relatively to Regional Gas Grids, since multiple technologies and imports are already all commercially competitive.
Storage capacity may not reflect public good of system security of supply.	▪ Storage continues to be commercially financed and investment only reflects need to meet typical seasonal fluctuations.	▪ Government imposes a compulsory stocking obligation on retailers to drive additional demand for storage. Cost is passed to end users.	▪ Strategic security of supply risk is likely to be significantly increased by the extensive use of hydrogen for critical transport links, increasing case for intervention.
Methane transmission network is now used exclusively to feed SMR.	▪ Provided SMR producers face a competitive constraint from other production technologies and/or imports, the methane network may be effectively prevented from increasing charges for fear of putting these SMR plants out of business. This constraint could potentially remove the need for price regulation.	▪ A regulated monopoly model may be preferable however, especially where the government is keen to secure returns for SMR investors.	

Source: Frontier Economics

A.1.2 Institutions and entities

Figure 55 High Hydrogen: Institutions and entities – market model

Institution	Functions	Market structure	Infrastructure funding	Important features
Methane import infrastructure owner-operator	Own & operate import terminal / interconnector	Existing market arrangements	Merchant (possibly supported by cap and floor)	
SMR owner-operator	Own & operate SMR conversion	Sells conversion services through tolling agreements	Project finance using toll model	Sells conversion only through tolling agreements
Electrolysis owner-operator	Own & operate electrolysis plant	Sells conversion services through tolling agreements	Project finance using toll model	
Hydrogen import infrastructure owner-operator	Own & operate import terminal / interconnector	Analogous to existing market arrangements for methane	Merchant (possibly supported by cap and floor)	
Methane transmission	Own & operate methane transmission infrastructure	Unregulated, commercial arrangements with SMR consumers	Infrastructure investors	Removal of regulation assumes that economics of SMR are sufficient to constrain pricing
Hydrogen distribution - pipes	Own & operate hydrogen distribution infrastructure	Regional monopolies with regulated returns	Regulated infrastructure investors	
Hydrogen distribution - lorries	Own & operate virtual pipeline infrastructure, primarily to fuelling stations	Competitive specialised logistics companies	N/A	
Hydrogen transmission	Own & operate hydrogen transmission infrastructure	Regional monopolies with regulated returns	Regulated infrastructure investors	
Hydrogen storage	Own & operate storage sites	Competitive market (as today)	Merchant	
Methane/hydrogen importer	Source methane or hydrogen from abroad	Buys from some exchange-based markets abroad	N/A	
Trader	Own gas during transit, optimise gas procurement, conversion and storage behaviour	Competitive national market, likely to be integrated with retail functions but may operate as stand-alone trader role	N/A	Contracts for SMR conversion using tolling agreements
System operator	System planning, operation and balancing	Regulated monopoly	N/A	Likely to be closely integrated across different gas networks
Retailer	Retails fuel to end users via direct pipeline connection, hedging gas prices and providing single billing point	Competitive national market with regulated supplier switching (as today)	N/A	

Source: Frontier Economics

Figure 56 High Hydrogen: Institutions and entities – additional-intervention model

Institution	Functions	Market structure	Infrastructure funding	Important features
Methane import infrastructure owner-operator	Own & operate import terminal / interconnector	Existing market arrangements	Merchant (possibly supported by cap and floor)	
SMR owner-operator	Own & operate SMR conversion	Sells conversion services through tolling agreements	Cap and floor supported	Sells conversion only through tolling agreements
Electrolysis owner-operator	Own & operate electrolysis plant	Sells conversion services through tolling agreements	Cap and floor supported	
Hydrogen import infrastructure owner-operator	Own & operate import terminal / interconnector	Analogous to existing market arrangements for methane	Merchant (possibly supported by cap and floor)	
Methane transmission	Own & operate methane transmission infrastructure	National monopoly with regulated returns	Regulated infrastructure investors	
Hydrogen distribution - pipes	Own & operate hydrogen distribution infrastructure	Regional monopolies with regulated returns	Regulated infrastructure investors	
Hydrogen distribution - lorries	Own & operate virtual pipeline infrastructure, primarily to fuelling stations	Competitive specialised logistics companies	N/A	
Fuelling station owner-operator and retailer	Own & operate fuelling stations, retail to private transport customers	Competitive market for fuelling, not dissimilar to today	Merchant	A fleet vehicle model does not change the market model, but may change bargaining dynamics
Hydrogen transmission	Own & operate hydrogen transmission infrastructure	National monopoly with regulated returns	Regulated infrastructure investors	
Hydrogen storage	Own & operate storage sites	Competitive market (as today)	Merchant	Additional demand driven by compulsory stocking obligation on retailers
Methane/hydrogen importer	Source methane or hydrogen from abroad	Buys from some exchange-based markets abroad	N/A	
Trader	Own gas during transit, optimise gas procurement, conversion and storage behaviour	Competitive national market, likely to be integrated with retail functions but may operate as stand-alone trader role	N/A	Contracts for SMR conversion using tolling agreements
System operator	System planning, operation and balancing	Public body	N/A	Likely to be closely integrated across different gas networks

Source: Frontier Economics

A.2 Methane Peaking

A.2.1 Significant risks and management options

Figure 57 Methane Peaking: Major issues and risks and management options

Issue or risk	Market management options	Options for additional intervention	Notes
Supply chain risk for AD	▪ Portfolio owner-operators to diversify risk. ▪ Long-term supply contracts (although today's market suggests this may be hard).		▪ Although this risk could be solved through vertical integration, this implies the feedstock businesses getting involved in relatively complex energy markets, which we think unlikely.
AD and syngas plants face risk around demand	▪ Long term offtake contracts.	▪ Contract for differences (similar to today's market models).	▪ Risk will depend on scope for output to be displaced by imports (or competing production technologies – which are likely to be constrained by feedstock availability). ▪ Vertical integration with demand is not likely to be a solution, since there is no long term guaranteed source of demand.
To maximise cost-effectiveness, buildings consumers need to switch between gas and electricity in response to price fluctuations	▪ Retail market offers contracts for heat (rather than gas or electricity) to minimise hassle for consumers. Limited retailer investment to provide this functionality allows for competitive market (a bit like mobile phone contract market).	▪ Where these retailers need or choose to invest in significant in-home assets (e.g. smart hybrid heat pump systems), regulated asset transfer pricing may be needed to allow retailer switching. ▪ Alternatively Government regulate final pricing (similar to heat networks).	▪ Government intervention is principally required to overcome increased barriers to retail competition in this segment of the market.
Gas and electricity become closer substitutes and demand patterns become more intertwined.		▪ Coordination between gas and electricity SO.	
Networks, particularly the distribution network, are used less than at present.	▪ Regulated charges to network users are based mainly on capacity.	▪ Regulated charges to network users are based mainly on capacity.	

Source: Frontier Economics

A.2.2 Institutions and entities

Figure 58 Methane Peaking: Institutions and entities – market model

Institution	Functions	Market structure	Infrastructure funding	Important features
AD methane producer	Own & operate AD production	100s of individual plants but portfolio owner-operators	Merchant	Bilateral feedstock contracts, ideally long-term with penalties for non-delivery
Syngas producer	Own & operate syngas production	30-40 syngas plants but portfolio owner-operators	Merchant	Biomass-fed plant are likely to source from biomass commodity markets
Low carbon methane importer	Source methane from abroad	Buys from some exchange-based markets abroad	N/A	
Import terminal	Own & operate methane import terminal	Existing market arrangements	Merchant	
Virtual pipeline	Own & operate gas trucking	Competitive national market of truckers	N/A	Grid connection infrastructure is owned by relevant grid
Methane distribution	Own & operate methane distribution infrastructure	Regional monopolies with regulated returns	Regulated infrastructure investors	
Methane transmission	Own & operate methane transmission infrastructure	National monopoly with regulated returns	Regulated infrastructure investors	
Methane storage	Own & operate storage sites	Competitive market (as today)	Merchant	
Trader	Own gas during transit to distribution network; optimise gas procurement and storage behaviour.	Competitive national market, likely to be integrated with retail functions but may operate as stand-alone trader role.	N/A	
System operator	System planning, operation and balancing.	Regulated monopoly	N/A	Likely to be closely integrated with electricity system operation given degree of interaction.
Fuel retailer	Retails fuel to end users, hedging gas prices and providing single billing point.	Competitive national market with regulated supplier switching (as today).	N/A	
Energy services retailer	Retails package of energy services (e.g. power, space heating/cooling, hot water) to end users, hedging energy prices, optimising energy use and providing single billing point.	Competitive national market with regulated supplier switching (as today).	N/A	Merges retailer and aggregator roles, enabling consumers to better optimise more complex heating system. May provide ancillary services to power networks. Contracts may be similar to mobile phones today with some optimisation kit in-house.

Source: Frontier Economics

Figure 59 Methane Peaking: Institutions and entities: additional-intervention model

Institution	Functions	Market structure	Infrastructure funding	Important features
AD methane producer	Own & operate AD production	100s of individual plants but portfolio owner-operators	CfD-supported commercial funding	Bilateral feedstock contracts, ideally long-term with penalties for non-delivery
Syngas producer	Own & operate syngas production	30-40 syngas plants but portfolio owner-operators	CfD-supported commercial funding	Biomass-fed plant are likely to source from biomass commodity markets
Low carbon methane importer	Source methane from abroad	Buys from some exchange-based markets abroad	N/A	
Import terminal	Own & operate methane import terminal	Existing market arrangements	Merchant	
Virtual pipeline	Own & operate gas trucking	Competitive national market of truckers	N/A	Grid connection infrastructure is owned by relevant grid
Methane distribution	Own & operate methane distribution infrastructure	Regional monopolies with regulated returns	Regulated infrastructure investors	
Methane transmission	Own & operate methane transmission infrastructure	National monopoly with regulated returns	Regulated infrastructure investors	
Methane storage	Own & operate storage sites	Competitive market (as today)	Merchant	
Trader	Own gas during transit to distribution network; optimise gas procurement and storage behaviour.	Competitive national market, likely to be integrated with retail functions but may operate as stand-alone trader role.	N/A	
System operator	System planning, operation and balancing.	Public body.	N/A	Likely to be closely integrated with electricity system operation given degree of interaction.
Fuel retailer	Retails fuel to end users, hedging gas prices and providing single billing point	Competitive national market with regulated supplier switching (as today).	N/A	

Institution	Functions	Market structure	Infrastructure funding	Important features
Energy services retailer	Retails package of energy services (e.g. power, space heating/cooling, hot water) to end users, hedging energy prices, optimising energy use and providing single billing point. May additionally install and own heating equipment.	Competitive national market with regulated supplier switching (as today). Where assets are owned, it may be necessary to have regulated asset transfer prices to facilitate a change of retailer. Alternatively price regulation could be used (as with heat networks).	N/A	Merges retailer and aggregator roles, enabling consumers to better optimise more complex heating system. May provide ancillary services to power networks. Contracts may be similar to mobile phones today with some optimisation kit in-house.
Body to deliver investment support (could be part of an existing entity)	Acts as creditworthy counterparty and therefore supports investment with low-financing cost.	Regulated body.	N/A	Separate from government but created to effect regulatory financial flows.

Source: Frontier Economics

A.3 Regional Gas Grids

A.3.1 Significant risks and management options

Figure 60 Regional Gas Grids: Major risks, issues and management options

Issue or risk	Market management options	Options for additional intervention	Notes
Supply chain risk for AD	▪ Portfolio owner-operators to diversify risk. ▪ Long-term supply contracts (although today's market suggests this may be hard).		▪ Although this risk could be solved through vertical integration, this implies the feedstock businesses getting involved in relatively complex energy markets, which we think unlikely.
AD and syngas plants face risk around demand	▪ Long term offtake contracts.	▪ Contract for differences (similar to today's market models).	▪ Risk will depend on scope for output to be displaced by imports (or competing production technologies – which are likely to be constrained by feedstock availability). ▪ Vertical integration with demand is not likely to be a solution, since there is no long term guaranteed source of demand.
Greater scope to generate electricity at the distribution level will create an opportunity to optimise this generation capacity	▪ Retail market offers contracts for combined energy services to minimise hassle for consumers and capture other sources of potential revenues (e.g. network and ancillary services). Limited retailer investment to provide this functionality allows for competitive market (a bit like mobile phone contract market).	▪ Where these retailers need or choose to invest in significant in-home assets (e.g. micro-CHP), regulated asset transfer pricing may be need to allow retailer switching. ▪ Alternatively Government regulates final pricing (similar to heat networks).	▪ Government intervention is principally required to overcome increased barriers to retail competition in this segment of the market.
Gas and electricity become closer substitutes and demand patterns become more intertwined.		▪ Coordination between gas and electricity SO.	

Issue or risk	Market management options	Options for additional intervention	Notes
SMR plants may face volume risk (e.g. because of risk of cheap imports or alternative production technologies, such as gasification and electrolysis).	▪ Where this risk is fairly limited, SMR can be financed using standard merchant financing arrangements.	▪ Where commercial finance cannot be raised at reasonable cost, a cap and floor arrangement similar to that for interconnection assets could be used.	▪ The financing risk to SMR is expected to be lower in this scenario compared with High Hydrogen, where electrolysis and imports are already commercially competitive.
Storage capacity may not reflect public good of system security of supply.	▪ Storage continues to be commercially financed and investment only reflects need to meet typical seasonal fluctuations.	▪ Government imposes a compulsory stocking obligation on retailers to drive additional demand for storage. Cost is passed to end users.	
New hydrogen infrastructure may imply different ownership arrangements (as established in transition).	▪ Hydrogen transmission infrastructure was built through series of regional CATO tenders and continues to have regionally-split ownership and maintenance.	▪ Regulated monopoly model like current NTS.	▪ These options are likely to reflect the mechanisms used to build hydrogen transmission infrastructure in the transition.
Micro-grids are likely to be so small as to prevent the use of a competitive market. The additional operational challenges may also benefit from integrated provision of storage and supply.	▪ Have a regulated monopoly supplier for these markets (this role could potentially be tendered for like a rail franchise).	▪ Have a public body, like a local authority-owned energy supplier, own and operate the local gas supply chain.	

Source: Frontier Economics

A.3.2 Institutions and entities

Figure 61 Regional Gas Grids- methane– market model

Institution	Functions	Market structure	Infrastructure funding	Important features
AD methane producer	Own & operate AD production	100s of individual plants but portfolio owner-operators	Merchant	Bilateral feedstock contracts, ideally long-term with penalties for non-delivery
Syngas producer	Own & operate syngas production	30-40 syngas plants but portfolio owner-operators	Merchant	Biomass-fed plant are likely to source from biomass commodity markets
Low carbon methane importer	Source methane from abroad	Buys from some exchange-based markets abroad	N/A	
Import terminal	Own & operate methane import terminal	Existing market arrangements	Merchant	
Virtual pipeline	Own & operate gas trucking	Competitive national market of truckers	N/A	Grid connection infrastructure is owned by relevant grid
Methane distribution	Own & operate methane distribution infrastructure	Regional monopolies with regulated returns	Regulated infrastructure investors	
Methane transmission	Own & operate methane transmission infrastructure	National monopoly with regulated returns	Regulated infrastructure investors	
Methane storage	Own & operate storage sites	Competitive market (as today)	Merchant	
Trader	Own gas during transit to distribution network, optimise gas procurement, conversion and storage behaviour	Competitive national market, likely to be integrated with retail functions but may operate as stand-alone trader role	N/A	Contracts for SMR conversion using tolling agreements
System operator	System planning, operation and balancing	Regulated monopoly	N/A	Likely to be closely integrated with electricity system operation given degree of interaction, as well as across different gas networks
Fuel retailer	Retails fuel to end users, hedging gas prices and providing single billing point	Competitive national market with regulated supplier switching (as today)	N/A	
Energy services retailer	Retails package of energy services (e.g. power, space heating/cooling, hot water) to end users, hedging energy prices, optimising energy use and providing single billing point	Competitive national market with regulated supplier switching (as today)	N/A	Merges retailer and aggregator roles, enabling consumers to better optimise more complex heating/generation system. May provide ancillary services to power networks. Contracts may be similar to mobile phones today with some optimisation kit in-house.

Source: Frontier Economics

Figure 62 Regional Gas Grids – hydrogen: market model

Institution	Functions	Market structure	Infrastructure funding	Important features
Shale gas producer	Own & operate shale production	Competitive exchange-based national market for methane	Merchant	
SMR owner-operator	Own & operate SMR conversion	≈80 SMR plants but portfolio owner-operators	Merchant	Sells conversion only through tolling agreements
Hydrogen distribution	Own & operate hydrogen distribution infrastructure	Regional monopolies with regulated returns	Regulated infrastructure investors	
Hydrogen transmission	Own & operate hydrogen transmission infrastructure	Regional monopolies with regulated returns	Regulated infrastructure investors	
Hydrogen storage	Own & operate storage sites	Competitive market (as today)	Merchant	

Source: Frontier Economics

Figure 63 Regional Gas Grids – micro grids: market model

Institution	Functions	Market structure	Infrastructure funding	Important features
AD methane producer	Own & operate AD production	All of these functions are provided by a single integrated, regulated monopoly provider (possibly following a tender for the market)	Regulated infrastructure investors	Bilateral feedstock contracts, ideally long-term with penalties for non-delivery
Syngas producer	Own & operate syngas production			Biomass-fed plant are likely to source from biomass commodity markets
Low carbon methane importer	Source methane from other grids			
Import infrastructure	Own & operate methane import infrastructure			
Methane distribution	Own & operate methane distribution infrastructure			
Methane storage	Own & operate storage sites			
Trader	Own gas during transit to distribution network, optimise gas procurement, conversion and storage behaviour			
Local system operator	System planning, operation and balancing			
Fuel retailer	Retails fuel to end users, hedging gas prices and providing single billing point			
Energy services retailer	Retails package of energy services (e.g. power, space heating/cooling, hot water) to end users, hedging energy prices, optimising energy use and providing single billing point			Merges retailer and aggregator roles, enabling consumers to better optimise more complex heating/generation system. May provide ancillary services to power networks. Contracts may be similar to mobile phones today with some optimisation kit in-house.
Virtual pipeline	Own & operate gas trucking	Competitive national market of truckers	N/A	Grid connection infrastructure is owned by relevant grid

Source: Frontier Economics

Figure 64 Regional Gas Grids – methane: Additional intervention model

Institution	Functions	Market structure	Infrastructure funding	Important features
AD methane producer	Own & operate AD production	100s of individual plants but portfolio owner-operators	CfD-supported commercial funding	Bilateral feedstock contracts, ideally long-term with penalties for non-delivery
Syngas producer	Own & operate syngas production	30-40 syngas plants but portfolio owner-operators	CfD-supported commercial funding	Biomass-fed plant are likely to source from biomass commodity markets
Low carbon methane importer	Source methane from abroad	Buys from some exchange-based markets abroad	N/A	
Import terminal	Own & operate methane import terminal	Existing market arrangements	Merchant	
Virtual pipeline	Own & operate gas trucking	Competitive national market of truckers	N/A	Grid connection infrastructure is owned by relevant grid
Methane distribution	Own & operate methane distribution infrastructure	Regional monopolies with regulated returns	Regulated infrastructure investors	
Methane transmission	Own & operate methane transmission infrastructure	National monopoly with regulated returns	Regulated infrastructure investors	
Methane storage	Own & operate storage sites	Competitive market (as today)	Merchant	
CfD counterparty	Acts as creditworthy counterparty and therefore supports investment with low-financing cost	Regulated body	N/A	Separate from government but created to effect regulatory financial flows. Credit underpinning could be similar to the current electricity generation CfD.
Trader	Own gas during transit to distribution network; optimise gas procurement, conversion and storage behaviour.	Competitive national market, likely to be integrated with retail functions but may operate as stand-alone trader role.	N/A	Contracts for SMR conversion using tolling agreements.
System operator	System planning, operation and balancing.	Public body.	N/A	Likely to be closely integrated with electricity system operation given degree of interaction, as well as across different gas networks.

Institution	Functions	Market structure	Infrastructure funding	Important features
Fuel retailer	Retails fuel to end users, hedging gas prices and providing single billing point	Competitive national market with regulated supplier switching (as today).	N/A	
Energy services retailer	Retails package of energy services (e.g. power, space heating/cooling, hot water) to end users, hedging energy prices, optimising energy use and providing single billing point. May additionally install and own heating equipment.	Competitive national market with regulated supplier switching (as today). Where assets are owned, it may be necessary to have regulated asset transfer prices to facilitate a change of retailer. Alternatively price regulation could be used (as with heat networks).	N/A	Merges retailer and aggregator roles, enabling consumers to better optimise more complex heating/generation system. May provide ancillary services to power networks. Contracts may be similar to mobile phones today with some optimisation kit in-house.
Body to deliver investment support (could be part of an existing entity)	Acts as creditworthy counterparty and therefore supports investment with low-financing cost.	Regulated body.	N/A	Separate from government but created to effect regulatory financial flows.

Source: Frontier Economics

Figure 65 Regional Gas Grids – hydrogen: Additional intervention model

Institution	Functions	Market structure	Infrastructure funding	Important features
Shale gas producer	Own & operate shale production	Competitive exchange-based national market for methane	Merchant	
SMR owner-operator	Own & operate SMR conversion	≈80 SMR plants but portfolio owner-operators	Cap and floor supported	Sells conversion only through tolling agreements
Hydrogen distribution	Own & operate hydrogen distribution infrastructure	Regional monopolies with regulated returns	Regulated infrastructure investors	
Hydrogen transmission	Own & operate hydrogen transmission infrastructure	National monopoly with regulated returns	Regulated infrastructure investors	
Hydrogen storage	Own & operate storage sites	Competitive market (as today)	Merchant	Additional demand driven by compulsory stocking obligation on retailers
Body to deliver investment support (could be part of an existing entity)	Acts as creditworthy counterparty, funnelling payments under the cap and floor regime	Regulated body, possibly integrated with SO	N/A	Separate from government but created to effect regulatory financial flows

Source: Frontier Economics

Figure 66 Regional Gas Grid – micro-grid – additional intervention model

Institution	Functions	Market structure	Infrastructure funding	Important features
AD methane producer	Own & operate AD production	All of these functions are provided by a single integrated public company, potentially owned by the relevant local authority	Regulated infrastructure investors	Bilateral feedstock contracts, ideally long-term with penalties for non-delivery
Syngas producer	Own & operate syngas production			Biomass-fed plant are likely to source from biomass commodity markets
Low carbon methane importer	Source methane from other grids			
Import infrastructure	Own & operate methane import infrastructure			
Methane distribution	Own & operate methane distribution infrastructure			
Methane storage	Own & operate storage sites			
Trader	Own gas during transit to distribution network, optimise gas procurement, conversion and storage behaviour			
Local system operator	System planning, operation and balancing			
Fuel retailer	Retails fuel to end users, hedging gas prices and providing single billing point			
Energy services retailer	Retails package of energy services (e.g. power, space heating/cooling, hot water) to end users, hedging energy prices, optimising energy use and providing single billing point			Merges retailer and aggregator roles, enabling consumers to better optimise more complex heating/generation system. May provide ancillary services to power networks. Contracts may be similar to mobile phones today with some optimisation kit in-house.
Virtual pipeline	Own & operate gas trucking	Competitive national market of truckers	N/A	Grid connection infrastructure is owned by relevant grid

Source: Frontier Economics

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