Hydrogen Transportation and Storage Infrastructure

Annex: Commercial Arrangements

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Contents

1 Introduction

This annex provides supporting information for the report Hydrogen Transportation and Storage Infrastructure: Assessment of Requirements up to 2035. It comprises three main sections:

- Section 2 provides information on the regulatory aspects of hydrogen transport and storage, including licensing and permitting.
- Section 3 investigates commercial arrangements from existing infrastructure sectors and explores how these could be applied to hydrogen transport and storage infrastructure.
- Section 4 presents the findings of Section 3 in a summary table.

2 Hydrogen transport and storage regulations

This section examines the existing regulation, planning and permitting regime for hydrogen developments, and how they might change in future. This includes licenses and exemptions, the level of application of the rules, and regulation of the wider natural gas industry to hydrogen provided as a fuel.

2.1 Development of a market regime

The production, distribution, storage and sale of hydrogen gas is not currently subject to specific legislation and is instead addressed through a combination of wider measures. The current gas market and supporting regulatory regime is well-established, with the modern market having been developed over several decades.

The principal legislation for the gas industry is the Gas Act 1986[1], which set the groundwork for privatisation of the gas industry. At the time, the industry was run as an effective fully integrated monopoly by British Gas Corporation, with the company's different functions progressively separated and opened to competition, e.g. in gas retail and distribution. This in turn required repeated amendments to the Gas Act and the introduction of new legislation.

Given the parallels between gas and hydrogen and our expectation of a phased market introduction, it is not expected that a fully realised hydrogen market will emerge in the short term, and that it may be necessary to accept pathways that offer a relatively limited degree of competition in the initial stages of the establishment of a hydrogen system.

2.2 Licensing

2.2.1 Ofgem and the Gas Act

The Gas Act and energy industry codes do not yet cover other forms of hydrogen transport (e.g., transportation by tanker or by barge), storage, or production. The Gas Act designates five gas industry activities as licensable:

- Gas transportation – conveying gas via pipeline, typically by operating a gas network but more rarely a gas storage site or through an interconnector.
- Gas shipping – arranging the physical delivery of gas by a transporter to a premises.
- Gas supply – supplying gas to a premises in terms of non-physical service (e.g. customer service, meter reading, billing customers etc).
- Gas interconnector – operating a gas interconnector.
- Providing a smart communication service.

These licences require holders to accede to industry codes, such as the Uniform Network Code (UNC) and the Retail Energy Code (REC). Requirements are designed for natural gas distribution and sale, although initial considerations have already been made as to how these will need to be amended to account for the delivery of hydrogen in pipelines, such as Cadent's Future Billing Methodology[2].

[1] Gas Act 1986: https://www.legislation.gov.uk/ukpga/1986/44/contents
[2] https://futurebillingmethodology.co.uk/wp-content/uploads/2022/05/FBM-Project-Progress-Report-Dec-21-Final-v1.2.pdf

Licences are issued by Ofgem, which also oversees modifications to the industry codes under a "living governance" regime. Part of the requirement of licenses is for "unbundling" – i.e., for transportation and shipping/supply to be undertaken by separate parties.

2.2.2 Exemptions

Schedule 2A[3] of the Gas Act and the Gas (Exemptions) Order[4] set out circumstances where parties do not have to obtain licenses to carry out otherwise licensable activities[5] – these generally being for small-scale and/or onsite activities. Exemptions include supply not connected to the gas networks, for very large users, and over short distances.

Under Section 8S[6] of the Gas Act 1986, owners of gas storage operators can apply for exemptions from the requirements contained in Section 19B (third party access) and Section 8R (independence of storage facilities) of the act.

Note also that gas storage is defined in the Gas Act as "storage in, or in a facility which is connected (directly or indirectly) to, a pipe-line system operated by a gas transporter". This means storage not linked to the transmission network or a distribution system (such as purely for on-site use) does not qualify as storage in the regulatory sense.

2.2.3 North Sea Transition Authority regulation

The North Sea Transition Authority[7] (NDTA) regulates other parts of the industry. These include offshore gas pipelines, carbon capture pipelines and offshore storage assets.

2.2.4 Applicability to hydrogen

Hydrogen production is not currently licensed, although there are strict health and safety requirements relating to the fuel which are covered in Section 2.3.2.

A low carbon hydrogen standard[8] has been published which refers to the amount of carbon that has been emitted in its production and perhaps a certification of the "greenness" could also be required in order to track carbon emissions from hydrogen production through to consumers. This would aid the transparency in the use of low carbon hydrogen production as opposed to other production methods. The UK currently does not have an official green gas certification scheme, although two schemes (the Biomethane Certification Scheme[9] and the Green Gas Certification Scheme[10]) have been recognised by BEIS[11] as of sufficient quality for use in offsetting Green Gas Levy payments.

The operators of these certificate schemes have expressed an interest in expanding their offering to include hydrogen, as well as the current biomethane and will create guidance as this market develops. However,

[3] https://www.legislation.gov.uk/ukpga/1986/44/schedule/2A
[4] https://www.legislation.gov.uk/uksi/2011/232/made
[5] Defined in the Gas Act as those where use by third parties is not necessary for operation of an efficient gas market
[6] https://www.legislation.gov.uk/ukpga/1986/44/section/8S
[7] Until March 2022, the Oil and Gas Authority
[8] https://www.gov.uk/government/publications/uk-low-carbon-hydrogen-standard-emissions-reporting-and-sustainability-criteria
[9] https://www.greengastrading.co.uk/certification-scheme/
[10] https://www.greengas.org.uk/
[11] https://www.gov.uk/government/publications/green-gas-levy-ggl-rates-and-exemptions/exemptions-from-the-green-gas-levy-ggl-approved-biomethane-certification-schemes

neither scheme enables the direct matching of certificates with the physical component of energy delivery, and government will have to decide whether it wishes to link certificates with wholesale delivery or maintain separation as is seen in existing certificate schemes to tackle market user concerns on greenwashing.

The EU's CertifHy[12] scheme – currently a voluntary hydrogen certification scheme – may therefore represent a potential comparator. The scheme provides Green or Low Carbon accreditation, with the former having a limit of 36.4gCO_2e/MJ or 131mtCO_2e/MWh[13]. Certificates are offered separately to the underlying physical delivery and have a lifetime of 12 months from production to be surrendered.

2.3 Permitting

Two key sets of permits must be achieved to commission hydrogen projects in the UK – planning permission and health and safety requirements.

2.3.1 Planning permission

Large hydrogen projects – particularly industrial-scale projects – are currently covered under the Nationally Significant Infrastructure Projects[14] (NSIP) process. This applies to generation projects over 50MW; pipelines over 800mm in diameter, over 40km long, operating at pressure over seven bar and supplying over 50,000 consumers; and underground storage projects over 43mn cubic meters or able to flow over 4.5mn cubic meters/day. For projects under this size, as well as elements including hydrogen pipelines, the Local Authority (LA) process under the Town & Country Planning Act[15] will apply.

The NSIP process leads to approval by the Secretary of State and is longer overall, but offers fewer opportunities for local appeal challenge and protest compared to the LA process – although both can be subject to Judicial Review.

In addition to planning permission, an Environmental Impact Assessment (EIA) must be completed in accordance with the Town & Country Planning (Environmental Impact Assessment) Regulations[16] or the Infrastructure Planning (Environmental Impact Assessment) Regulations[17] for the local and nationally significant infrastructure planning regimes respectively. This impact assessment is required for all storage of 200,000 tonnes or more of chemical products and production facilities making basic inorganic chemicals (which include hydrogen).

An assessment is also required at the planning authority's discretion for underground storage of combustible gases where the area of the structure exceeds 500m^2 or it is to be sited within 100 metres of controlled waters, or where a chemical storage facility exceeds 0.05 hectares, or 200 tonnes of products will be stored at any time. Pipelines will also generally require EIAs, while carbon capture pipelines and storage facilities universally require an EIA.

[12] https://www.certifhy.eu/

[13] This is set as 60% lower than the benchmark for hydrogen production
Hydrogen can be certified green, as opposed to low carbon, in relation to the proportion of renewable energy used in primary production

[14] https://infrastructure.planninginspectorate.gov.uk/

[15] https://www.legislation.gov.uk/ukpga/1990/8/contents

[16] http://www.legislation.gov.uk/uksi/2017/571/introduction/made

[17] https://www.legislation.gov.uk/uksi/2017/572/contents/made

A Town & Country application should take no more than six months and a NSIP around 12-15 months, while an EIA will take around a year to complete. In practice, appeals and reviews can add significantly to this timeline, particularly for large or controversial projects, with multi-year application and appeal processes not uncommon. We note, however, that it remains to be seen how accepting the public will be of large-scale hydrogen storage, recognising the concerns around fracking and grid-scale Li-ion batteries.

2.3.2 Health and Safety

The UK Health and Safety Executive (HSE) controls relevant requirements in this area. These are stricter for hydrogen than for natural gas, as hydrogen is both more explosive and - in the UK - less well understood than natural gas. These are as follows:

- The Gas Safety (Management) Regulations[18] (GSMR), which control the quality of natural gas injected into the public gas networks. Among other requirements, the GSMR restricts hydrogen content in the gas mixture to under 0.1%
  - Various hydrogen innovation projects, including HyNet[19] and HyDeploy[20], are working with HSE to understand how GSMR can be revised to permit higher levels of hydrogen in the public gas networks, to either 20% or 100%
- The Pipeline Safety Regulations[21], which set engineering standards for gas pipelines in terms of design, construction, operation and maintenance, and decommissioning
- The Planning (Hazardous Substances) Regulations[22] and Control of Major Accident Hazards Regulations[23] (COMAH), which cover hydrogen storage in different quantities and which require strategies and safety plans
  - Consent is required to store more than two tonnes of hydrogen (67.2MWh) and further consent for over five tonnes (168MWh)
- The Dangerous Substances and Explosive Atmosphere Regulations[24], which set requirements for equipment and protective systems from storage and processing of chemicals including hydrogen
- The International Carriage of Dangerous Goods by Road Regulations[25], which cover transportation of hydrogen by road and set standards for pressure vessels used
  - This regulation is commonly abbreviated to ADR referring to the French “Accord Européen Relatif au Transport international des marchandises dangereuses par route”
  - A study completed in 2018 by HyLAW[26] concluded that existing standards have been developed for relatively small market volumes and short delivery distances. These will require revision and

[18] https://www.hse.gov.uk/pubns/priced/l80.pdf
[19] https://hynet.co.uk/
[20] https://hydeploy.co.uk/
[21] https://www.hse.gov.uk/pubns/priced/l82.pdf
[22] https://www.legislation.gov.uk/uksi/2015/627/contents/made
[23] https://www.hse.gov.uk/comah/background/comah15.htm#:~:text=COMAH%20aims%20to%20prevent%20and,seriously%20as%20those%20to%20people.
[24] https://www.hse.gov.uk/fireandexplosion/dsear.htm
[25] https://www.hse.gov.uk/cdg/#:~:text=Carrying%20goods%20by%20road%20or,chemical%20burn%20or%20environmental%20damage.
[26] https://www.hylaw.eu/

adaption in light of new materials for increasing capacities, improving payload of hydrogen trailers and allowing hydrogen delivery at larger scales.

The current HSE structure is designed for the current hydrogen use-cases: typically, large-scale use in industrial and chemical processes. The suitability of these for small-scale commercial and domestic uses like domestic appliances and vehicle fuelling has not been established, and considerable revision of rules and regulations will be required – as is already being seen in the GSMR via real-world innovation demonstration projects.

Key take-aways

While hydrogen is produced, traded and consumed in large quantities in the GB market, it is not currently explicitly regulated as a fuel distinct from natural gas or as a consumer commodity for the mass market recognising the market maturity for hydrogen is in a different place to natural gas. Both are key gaps which will need to be met before hydrogen can reach the necessary scale to have broad decarbonising impacts.

Further, the health and safety implications of wide usage are not yet well understood, and therefore careful research is being undertaken in advance of widespread transportation and storage of hydrogen given its chemical properties.

3 Description of commercial arrangements in similar sectors

The main report discusses four potential *commercial configurations* that could be applied to hydrogen:

- ***Commercial Configuration* #1** Small users, with decentralised local electrolysers suitable to meet demand with local production, and limited above-ground storage to mitigate production/ demand mismatch risk.
- ***Commercial Configuration* #2** Small users, with semi-decentralised electrolyser production, with local distribution and above-ground storage to mitigate production/ distribution/ demand mismatch risk.
- ***Commercial Configuration* #3** Clusters of medium and large users, with designated regional hydrogen pipelines, large electrolysers or CCUS-enabled steam methane reformation (SMR) or bioenergy with carbon capture and storage (BECCS) production of hydrogen, salt-cavern or linepack storage.
- ***Commercial Configuration* #3b (extension of *Commercial Configuration* #3 to consider hydrogen for heat)** Heating use, either with a designated regional or national pipeline or blending of up to 20% into existing gas networks, storage in salt caverns, linepack or disused oil and gas fields. Production assets would include large electrolysers, CCUS-enabled SMR or BECCS.

This section discusses commercial arrangements from existing similar sectors to understand if and how these could be applied to the above *commercial configurations*. Five existing sectors are considered as follows:

- Large systems serving regional or national markets (Section 3.1)
- Small distribution systems (Section 3.2)
- Energy storage systems (Section 3.3)
- Electricity interconnectors (Section 3.4)
- Refined petroleum products (Section 3.5)

3.1 Large systems serving regional or national markets

Key take-aways

The market for Natural Gas is a mature and liquid, with rules that are well defined and developed over time.

However, these did not evolve "naturally", being layered onto an existing well-established public industry.

Price controls are fundamental to governance of monopoly networks, with regular reviews of funding mechanisms.

Network planning and price control reviews are expensive and lengthy processes.

In large systems, transportation roles are typically segmented in transmission (high volume, long distance) and distribution (lower volume, shorter distance) activities, as described below for the current Natural Gas arrangements. These arrangements are broadly replicated in the electricity industry for transmission and distribution systems.

3.1.1 Natural gas transmission

The GB gas industry is served by the National Transmission System (NTS), which moves large volumes of gas at high pressure up and down the country, connecting major points of demand (power stations, centres and industrial clusters) with supply sources (North Sea and other beach terminals, interconnectors, Liquified Natural Gas (LNG) terminals, storage facilities, and Distribution Networks (DNs)).

3.1.1.1 Ownership

The NTS is operated by National Grid Gas Transmission (NGGT), one of the members of the National Grid group. It is responsible both for owning and maintaining the NTS assets (the transmission owner role), and for operating the gas system to maintain pressure and ensure there is sufficient supply to meet demand (the system operator role). National Grid is a publicly traded company on the London Stock Exchange.

3.1.1.2 Operation

NGGT holds a gas transporter licence[27], granted by Ofgem. A transporter licence authorises its holder to convey gas through pipelines, with NGGT's being supplemented by numerous special licence conditions given its central role within the gas industry. This includes the requirement to meet domestic customer supply security standards which requires the transporter to make available a supply of gas which would equal the peak aggregate daily demand seen in at least the previous fifty years and is likely to be exceeded only in one in every twenty years.

It is subject to price controls to prevent it abusing its monopoly positions, and these are periodically recalculated. The current price control is called RIIO-GT2 and run from April 2021 to March 2026. This sets maximum allowed revenue that NGGT may recover each year, allowing it to charge consumers enough to maintain its assets, expand to meet future demand, and make a reasonable return.

As a transporter, NGGT is bound by the UNC, which is the gas industry's primary rulebook for gas transporters and shippers. This sets out the obligations on industry trading parties for operating within the market, many of which fall on NGGT due to its system operation role. These include monitoring and reporting the average calorific value (CV) of the gas in the system each day. NGGT is also responsible for maintaining gas quality in accordance with the GSMR limit and preventing off-specification gas from entering the system.

At each supply point NGGT has a Network Entry Agreement with the terminal operators which govern when and how gas is input into the network. Amongst other items this includes the exact gas specification, the rate at which volumes can be input, the communication protocols in notification of input volumes, any metering obligations including maintenance and testing and how off-specification gas will be handled should any be detected. Where there are adjacent beach terminal points these are handled as Aggregated System Entry Points (ASEPs) to allow for optimal use of these beach terminals and ease the purchase process for gas shippers of entry capacity at these points. For example the St Fergus ASEP is a combination of St Fergus Shell, St Fergus Mobil and St Fergus North Sea Midstream Partners gas terminals.

[27] https://epr.ofgem.gov.uk/Content/Documents/Gas_transporter_SLCs_consolidated%20-%20Current%20Version.pdf

To transport gas around the network gas shippers are required to reserve entry capacity where they are inputting gas into the network, pay transportation charges from the point of entry to the point of exit, and dependant on where they are transporting to, exit capacity. Volumes that have not exited the network are said to be left at the National Balancing Point (NBP) i.e. volumes bought and sold at the NBP do not incur transportation charges. Charges for entry, exit and transportation are set by a charging methodology which is periodically updated.

The booking of entry and exit capacity is carried out through a series of auctions held by NGGT throughout the year allowing gas shippers to book from years in advance to within day where gas shippers can fine tune their requirements. The minimum volume offered through these auctions is mandated as part of the UNC. Since there is a physical limit to the volume of gas that can be input and transported around the transmission network the volume of entry and exit capacity available is limited and so at times the volume of capacity available to gas shippers can be insufficient to meet their demand. NGGT makes both firm and interruptible capacity available to order to try to satisfy overall requirements and meet their obligations of operating a safe and secure network. Gas shippers that fail to reserve sufficient entry and/or exit capacity for their needs are charged punitive overrun rates set by the charging methodology.

Exit from the transmission system can either be at a point of demand (power stations and industrial clusters) or points that connect to the gas distribution network as described below.

3.1.1.3 Access

NGGT is obligated to facilitate connections to the NTS under reasonable terms, and there is a formal, well-established process for requesting connections to the NTS. The connection charging methodology is defined in NGGT's licence and supported by UNC processes.

The connection process involves a series of steps that involve information provision, feasibility studies, paying fees and fronting credit. The cost and timescales will depend on the characteristics of the connection, such as flow rate, footprint, and number of users. This will determine whether a standard connection is suitable, or if a bespoke solution is needed. A standard connection will cost £13,000 for the application, with an additional £14,000 if a feasibility study is needed. It will usually take three months before a connection offer is made, or up to nine months for a complex connection. The cost and timescales of the physical work will vary but can span years and millions of pounds.

3.1.2 Natural gas distribution

With the exception of transmission-connected users (large power stations and heavy industry), most gas customers are connected to the distribution system that takes gas off of the NTS. These lower-pressure pipes are divided into 13 local distribution zones (LDZs), based around groups of offtake from the NTS. These are served by four regional gas distribution network (GDN) companies.

3.1.2.1 Ownership

The GDNs are private monopoly companies regulated by Ofgem via their transporter licences. The four GDNs are Northern Gas Networks (in the North of England), Wales & West Utilities (in Wales and the west of England), SGN (in Scotland and southern England), and Cadent (in a band across the rest of England, mostly London, East Anglia and the Midlands). Each is a privately owned company, and they are typically owned by pension funds, investment firms, and sovereign wealth funds.

3.1.2.2 Operation

The GDNs are responsible for owning and operating the distribution assets in their LDZs, primarily pipes and compressor stations. They are subject to price controls to prevent them abusing their monopoly positions, which are periodically recalculated. The current price controls are called RIIO-GD2 and run from April 2021 to March 2026. The price controls set maximum allowed revenue for the companies for each year, allowing them to charge consumers enough to maintain their assets, expand to meet future demand, and make a reasonable return. Transportation charges are levied on gas shippers based on the anticipated maximum hourly capacity of the supply points which users can amend and the GDNs publish a charging statement based on the charging methodology set out in the UNC. A revised statement is also published each year in line with requirements under the UNC.

A GDN's licence requires it to maintain continuity of supply to customers as per the domestic customer supply security standards set for the transmission operator, offer reasonable connection terms, maintain an investment-grade credit rating, operate a priority services register to support vulnerable customers in the event of an emergency, and many other obligations. As licensed gas transporters, they must also accede to the UNC, which contains the majority of their market obligations such as booking capacity for taking gas off the NTS for their LDZs.

3.1.2.3 Access

The GDNs are obligated to facilitate connections to their networks under reasonable terms, and there is a formal, well-established process for requesting these connections. Those connected will need to provide information such as site location, where they would like their gas meter to be located, and its distance from the property boundary. Timescales and costs will vary depending on the size of the connection, which might range from a single household to a large non-domestic customer or housing estate. However, a typical small connection will cost around £500 plus a rate per meter of pipe, and the physical works typically take six to eight weeks.

The commercial arrangements and key takeaways for natural gas transmission and distribution systems are summarised in Table 1.

Table 1: Commercial arrangements for natural gas transmission and distribution systems.

Sector	**Natural gas transmission**	**Natural gas distribution**
Arrangements	The transmission network and each distribution network is owned by a separate legal entity (NGGT and the GDNs), with NGGT also fulfilling the role of national system operator. Production, storage, shipping (booking network capacity) and supply are all unbundled activities. Networks must meet security of supply standards (network resiliency) and must provide connection offers to all applicants, based on the realistic costs of connecting them to the networks. Prices to users for maintaining a connection and flowing gas are regulated under price controls.	
Licensing	Licensed and regulated, including monopoly price controls, by Ofgem	
Key take-aways	• The market for natural gas is a mature and liquid, with rules that are well defined and developed over time • However, these did not evolve "naturally", being layered onto an existing well-established public industry • Price controls are fundamental to governance of monopoly networks, with regular reviews of funding mechanisms • Network planning and monopoly price control reviews are expensive and lengthy processes	
Relevant *Commercial Configuration*(s)	Directly relevant to #3 and #3b where pipelines are being operated	

3.2 Small distribution systems

This section examines various local distribution systems for energy vectors, as well as small water networks.

3.2.1 Heat networks

The heat network market in GB consists of around 14,000 networks, according to[28] BEIS in 2018, with 12,000 of these "communal" networks around a single building – for example a block of flats – and 2,000 "district", serving multiple buildings. According to[29] the Association for Decentralised Energy in 2018, there were 17,000 heat networks: 11,500 communal and 5,500 district.

Government sees district heat networks as a key development area for future low-carbon heat and is introducing regulation, having appointed[30] energy sector regulator Ofgem as the heat network regulator in December 2021. This is with the intention of increasing consumer and investor ensuring fair prices and decarbonisation of networks.

[28] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/774586/heat-networks-ensuring-sustained-investment-protecting-consumers.pdf
[29] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/774586/heat-networks-ensuring-sustained-investment-protecting-consumers.pdf
[30] https://www.gov.uk/government/news/uk-government-announces-major-expansion-of-heat-networks-in-latest-step-to-power-homes-with-green-energy

Key take-aways

Heat networks are currently poorly regulated, with a lack of transparency for customers and government.

Regulation is only voluntary, despite being inherently monopolistic with increasing awareness of consumer harms and restriction of market growth driving introduction of regulatory control.

There is a risk of similar outcomes emerging for small local hydrogen networks without sufficient oversight.

3.2.1.1 Ownership

There are a range of ownership models for heat networks. Communal (single building) networks tend to be owned by the building owner or the building management company. District networks covering multiple buildings have historically been owned by LAs, social housing providers, universities, NHS Trusts or other public bodies. Due to the increasing scale – and investment need – of modern networks, third parties are increasingly involved.

This includes large infrastructure developers such as Vattenfall[31], Peel[32], SSE[33] and Statkraft[34]. These parties typically provide expertise and capital, operating in partnership with LAs, which have the legal authority and large anchor loads, to develop and expand networks. The entry of pure-play investors such as debt providers (banks) is not yet well established due to relatively high risk factors, but part of the intention of the introduction of regulation to the market is to reduce these risks and encourage large-scale debt deployment to reduce costs.

The concept of third-party access is common in European heat networks in more development markets, such as the Scandinavian countries and increasingly in the Netherlands. This effectively separates some of the heat production role to other bodies, typically those with waste heat to input to networks. In larger networks, it provides a level of competition, and the Netherlands is reportedly considering development of “heat transmission networks” to increase the size of networks and inter-network trading opportunities. This separation also reflects the different useful lives of assets – 60 years for networks, but 15-20 years for heat production.

3.2.1.2 Operation

Heat networks generally have the generator, network and supplier roles contained within a single party, which owns and operates the assets and has a commercial relationship with the consumer. This is more efficient in what are mostly relatively small networks but offers no competition. Customers who are connected to heat networks have the option of electrical heating and can often connect to gas networks to provide competition, but these solutions are more complex and require more capital expenditure than supplier switching.

Contracts will set prices to consumers. These can be structured in term of a standing charge for the property per year, either on a flat rate for all consumers, based on property square-meterage, or tailored to individual properties, an energy cost per kWh (where metering is present), or – as with most regulated

[31] https://heat.vattenfall.co.uk/
[32] https://peellandp.co.uk/what-we-do/natural-resources-and-energy/sectors/district-heating/
[33] https://www.sseenergysolutions.co.uk/news-and-insights/case-studies/sse-heat-networks-sse-green-electricity-for-a-net-zero-future
[34] https://www.statkraft.com/what-we-do/district-heating/

networks – a combination of standing and unit costs. Prices will usually change annually, reflecting the costs seen by the network owner-operator, including capital recovery, maintenance, operation, and fuel costs. Prices are not currently regulated.

As heat networks become larger, there may be a case for splitting these roles and allowing some competition. Though the scale of networks would have to increase by an order of magnitude or two, in order to support this, it is not unlikely that future heat networks will be much larger.

Current regulation is largely voluntary, through the Heat Trust, though there are some requirements in the Heat Networks (Metering and Billing) Regulations 2014[35] to meter heat offtake and provide bills based on this. The Heat Trust's[36] rules are mostly around consumer protection, guaranteed standards of performance, and fair billing and cost allocation. Future consumer protection regulation will be based in large part on the Heat Trust's rules, but will not be optional.

The lack of competition and single party operation makes the industry more vulnerable to company failure. There is currently no procedure to cover operator-failure, which could leave consumers without a heating provider. Government is developing "step-in" arrangements to cover scenarios of operational failure or insolvency, or where operators are de-authorised and not permitted to continue operating under regulation. It is considering commercial solutions, supplier continuity plans, special administration and operator of last resort mechanisms, but has to date published no decisions on the topic.

3.2.1.3 Access

There is no right of access to parties to connect to heat networks; similarly, there is no right for third party heat producers to connect to sell heat into a network. This means that the heat supply through the network is effectively a monopoly, though given that there are other fuel sources – for example, gas is likely to be available and electricity certainly will be – the networks are not considered monopoly providers of services.

Government consulted on[37] giving LAs powers to designate "Heat Network Zones" in late 2021. It is currently analysing feedback. The proposal suggested that LAs would be able to identify and designate Heat Network Zones, within which buildings would be required to connect to the heat network. Initially this would be public sector buildings and new buildings but may expand over time to include existing non-domestic and even domestic buildings.

Zone operators would be required to consult with other local stakeholders, including public sector bodies and electricity and gas network operators. Many questions remain to be answered from the consultation, but it seems likely that at least some buildings will be legally required to connect to heat networks, providing an "anchor load" to allow development of the network, which can then expand freely to other buildings within the area.

Again, it is not clear that demand or production users within the region will have a right to connect to the heat network. Based on the consultations issued to date, government does not yet appear to have considered this issue.

The commercial arrangements and key takeaways for small distribution systems are summarised in Table 2.

[35] https://www.gov.uk/guidance/heat-networks
[36] https://heattrust.org/about
[37] https://www.gov.uk/government/consultations/proposals-for-heat-network-zoning

Table 2: Commercial arrangements for small distribution systems

Sector	**Heat networks**
Arrangements	Typically, vertically integrated heat generation, transportation and supply, with most heat networks supplying relatively small numbers of consumers. Ownership tends to include a local authority and/or other public sector body (e.g., hospital or university), with partnership to a large infrastructure providers increasingly common particularly as larger networks emerge. Prices and costs for heat and infrastructure are bundled; they are not regulated and though seek to achieve price points below the alternative cost of gas-fired central heating, this is not always achieved.
Licensing	Not currently licensed and with only limited regulations regarding metering and billing based on heat usage. The Heat Trust maintains a voluntary consumer protection code, primarily for domestic consumers, and government has recently appointed Ofgem as the heat sector regulator with the intention of introducing a full authorisation regime. The 2022 Queen's Speech outlined an Energy Security Bill that will introduce this regulation, which – allowing for parliamentary time and notice of implementation – we estimate might see new rules implemented from April 2024.
Key take-aways	• Heat networks are discrete networks of limited size, only present in some parts of the country, and are self-contained with their own heat source as part of the network. • Currently subject to very limited regulation, with a lack of transparency for customers and government. • Regulation is currently only voluntary, despite existing business propositions being inherently monopolistic. However, increasing awareness of consumer harms and restriction of market growth are driving the introduction of regulatory control. • With a stable and certain regulatory regime investor and developer confidence in the sector is likely to improve alongside the growing pressure to decarbonise heat as part of the net zero transition. There is a risk of similar outcomes emerging for small local hydrogen networks without sufficient oversight.
Relevant *Commercial Configuration*(s)	Directly relevant to #3 on pipelines, also provides example of vertical integration and introduction of new regulator to a sector to drive growth.

3.2.2 Independent power networks

Independent power networks come in two types: licensed independent networks, and unlicensed private networks. The former tends to be slightly larger, and may have a greater number of domestic customers, as regulatory exemptions are easier to achieve for non-domestic customers only. The latter often link energy generation directly to consumers, in order to avoid public network charges and levies.

Key take-aways

Larger networks with domestic customers are licensed, to provide customer protections, while networks that are smaller or non-domestic only can be unlicensed.

Generation may be connected to network, but users are not beholden solely to this. Hydrogen rules will similarly need to recognise a need for third-party access rules and a right to disconnect.

Regulation or justification of charges less rigorous than directly regulated networks.

3.2.2.1 Ownership

Licensed independent networks are owned by one of the 15 independent distribution network operators (IDNOs); these include offshoots of major European utilities (including Vattenfall) and fully independent parties (like Last Mile Electricity). Unlicensed network providers include these parties, which will often operate Special Purpose Vehicles (SPVs) to run networks, as well as Local Authorities – which may run power networks alongside heat networks – generators, and other parties. Some IDNOs are multi-utility, offering gas, water and telecoms connections alongside power connections.

Small networks, for example on housing or commercial developments, will often be owned by the site owner or developer, as an additional revenue stream or cost-saving measure. There are also examples of generators owning local networks to supply low-cost power to regional businesses; Baglan Bay power network was one such example, based around the 525MW gas-fired power station.

Community generators can also own these networks, especially in the case of a private wire to a single consumer. For example, Wadebridge Renewable Energy Network owns a 100kW solar farm and private wire to neighbouring South West Water sewage treatment works.

3.2.2.2 Operation

Licensed independent networks are operated under license from Ofgem. They are subject to most of the same rules and regulations as regional incumbent distribution network operators with regards to network availability and providing security of supply, as well as maintaining a priority services register and an investment-grade credit rating, requiring financing disclosure and limited debt. Domestic consumers are also protected from high charges, as these are capped at the level of Distribution Network Operator (DNO) charges in each region.
Private wire customers do not benefit from these protections. These networks operate under the Electricity (Class Exemptions from the Requirement for a License) Order[38]; this sets out categories of exemption. Broadly these are:

- For generators, where generation is under 50MW or is offshore.
- For distributors, to unlimited non-domestic customers or up to 1MW of domestic load (from onsite generation) or 2.5MW of domestic load (from generation from the public system).
- For suppliers, of up to 5MW including no more than 2.5MW of domestic consumers, where they generate this power themselves, where they are re-selling power bought from a licensed supplier, or for arrangements across a single site.

[38] https://www.legislation.gov.uk/uksi/2001/3270/body

Licensed and unlicensed networks are connected to the public networks, and the boundary point is effectively regarded as a single customer connection to the network by the regional DNO (or the transmission owner, as may be the case). The network therefore benefits from the same security of supply standards as any other customer, with regards to energy received from, or exported to, the public network. This alleviates many of the concerns regarding security of supply which an islanded microgrid may experience – though where there is flexible generation and/or storage onsite, it is possible that the network connection may be undersized in order to minimise costs, which could still leave onsite customers unable to access power in the event of onsite assets suffering an outage. This risk must be managed by the IDNO or unlicensed network operator, with IDNOs required to meet regulatory standards while unlicensed operators are not – though their contracts with users will likely set similar standards to protect users.

3.2.2.3 Access

Like the public networks, licensed IDNOs are required to provide connection offers to all parties which request them. However, unlicensed independent networks have no obligation to connect new users – although many will, if they are located in the appropriate region, as a means of expanding their user-base and future revenues.

For users who are connected, there is a right of third-party supply for all users, whether connected to a licensed or unlicenced network. This means that networks must set out their (reasonable) charges for use of the network, so that users can opt for a public supplier rather than accepting the supplier which the network operator designates. In practice, few will take this option as the owner/operator and their preferred supplier should be able to provide a more economical solution to providing power, but the option is protected in law and is believed to keep operators from exploiting their otherwise captive audience of connected customers.

The commercial arrangements and key takeaways for independent power networks are summarised in Table 3.

Table 3: Commercial arrangements for independent power networks

Sector	Independent power networks
Arrangements	Can be licensed or unlicensed; unlicensed networks have much greater freedoms but are restricted to supplying 1MW of domestic demand (unlimited for non-domestics). There are 15 licensed Independent Distribution Network Operators (IDNOs), many of which also operate in gas (and some in water). Network charges are capped at the levels of charges for the regional DNO for IDNO customers; for unlicensed networks charging methodology must be based on relevant costs and are approved by Ofgem.
Licensing	IDNOs hold a lighter-touch version of the DNO licence from Ofgem, which retains the duty to connect applicants and meet security of supply standards. 'Private' networks are unlicensed but are still subject to some service standards and must provide third party access rights.
Key take-aways	• Larger networks with domestic customers are licensed, to provide customer protections, while networks that are smaller or non-domestic only can be unlicensed. • High probability that generation is connected to network, but users are not beholden solely to these. Hydrogen rules will similarly need to recognise need for third-party access and right to disconnect. • Regulation or justification of charges less rigorous than directly regulated networks.
Relevant *Commercial Configuration*(s)	Directly relevant to #3 on pipelines

3.2.3 Independent gas networks

Independent Gas Transporters (IGT)s develop and operate small-scale gas transportation networks, typically alongside new housing and commercial developments. They are the counterpart to IDNOs and act to provide a competitive alternative to connecting a development via the incumbent GDN.

3.2.3.1 Ownership

IGTs are required to hold a transporter licence, but this is amended to cut out various requirements that are unnecessary compared to those held by the GDNs and National Grid. There are currently 10 IGTs in GB, whose networks serve over 1mn customers.

3.2.3.2 Operation

IGT networks are operated under license from Ofgem. They are subject to most of the same rules (i.e. gas transporter/shipper arrangements) and regulations as GDNs with regards to network availability and providing security of supply, as well as maintaining a priority services register and an investment-grade credit rating, requiring financing disclosure and limited debt. IGT charges are regulated via a "Relative Price Control", which caps charges at a level broadly equivalent to the local GDN's charges.

In addition to their licences, IGTs accede to and operate their own version of the UNC that is bespoke to their requirements – the IGT UNC. However, it is fundamentally very similar and often makes direct reference to the UNC for areas where there are no special IGT rules.

3.2.3.3 Access

Like the GDNs, IGTs are required to provide connection offers to all parties which request these. Users of their networks have a right of third-party supply, which requires the IGTs to set out (reasonable) charges for use of their network, so that users can choose their own supplier rather than accepting the supplier the IGT registered the site with. This is no different from the arrangements for GDN users.

The commercial arrangements and key takeaways for independent gas networks are summarised in Table 4.

Table 4: Commercial arrangements for independent gas networks

Sector	Independent gas network arrangements
Arrangements	Independent Gas Transporters (IGTs) develop and operate small-scale gas transportation networks, typically alongside new housing and commercial developments. They are the counterpart to IDNOs and act to provide a competitive alternative to connecting a development via the incumbent GDN. Charges are regulated based on the regional GDN, and networks are required to connect applicants.
Licensing	Operated under a modified transporter licence from Ofgem, with most of the same provisions for security of supply and consumer protections as the regional GDN’s.
Key take-aways	• IGTs operate very similarly to GDNs and IDNOs, being part of the ‘public’ network and market. • They are less heavily regulated than GDNs but are still licensed and face extensive obligations. • We see limited lessons for hydrogen as these are largely just extensions of the wider system.
Relevant *Commercial Configuration*(s)	Directly relevant to #3 on pipelines.

3.2.4 The Scottish Independent Networks (SINs)

Scotland is host to five independent gas networks that are physically islanded from the rest of the system and supplied with LNG or Liquefied Petroleum Gas (LPG). Known as the SINs under the UNC (or Statutory Independent Undertakings under Ofgem regulations), these are a legacy of the conversion of the gas system from town gas to natural gas. Located at Wick, Thurso, Stornoway, Oban, and Campbeltown, the remoteness of these communities meant it was uneconomic to extend the then-new NTS to serve them.

Key take-aways

Despite physical separation from main gas networks, these are treated as part of single GB gas system – including Stornoway’s system, which uses a different fuel.

Rules for switching and connections are the same as for user on the wider network, as is billing.

Small hydrogen networks could be run on exactly these principles, including development and operation by regional GDNs. However, the rules may have limitations at scale.

3.2.4.1 Ownership

These five networks are owned by SGN, the GDN that serves all of Scotland. They are accounted for[39] within its price control, the most recent of which is RIIO-GD2.

3.2.4.2 Operation

The five SINs serve around 9,000 consumers. Those that use LNG are supplied from the Isle of Grain LNG terminal in the Thames estuary, which is delivered via tanker truck to local storage facilities. LPG is delivered to local storage at Stornoway by ship.

The SINs are treated as part of the GB gas market despite being physically distinct from it, being subject to the same gas balancing, capacity booking and charging rules as other sites (albeit we understand that much of this is a nominal process, given that gas cannot physically flow from the transmission system to these offtakes). They also have their own rules for CV, which is normally recalculated every day for the other 13 LDZs of the GB system, but instead set in advance for the SINs by the declared value of their deliveries.

Charges in the SINs are mostly the same as the equivalent charges for other customers in SGN's regions, with the exception of a distinct Exit Capacity Charge used for the four served with LNG. Stornoway's network charges are set in such a way to never be higher than those for mainland customers.

3.2.4.3 Access

Being served by SGN, the SINs are subject to the same access rules as the interconnected public network when it comes to connection and access. New connections to the network can be requested by prospective customers and are funded under SGN's price control. They are then free to choose their supplier as normal.

The commercial arrangements and key takeaways for Scottish Independent Networks are summarised in Table 5.

[39] https://www.sgnfuture.co.uk/wp-content/uploads/2019/12/Appendix-017-SGN-SIU.pdf

Table 5: Commercial arrangements for Scottish Independent Networks

Sector	Scottish Independent Networks (SINs)
Arrangements	Scotland is host to five physically islanded gas networks, supplied with liquefied natural gas (LNG) or liquified petroleum gas (LPG), as the locations of these communities made it uneconomic to extend the National Transmission System (NTS) to serve them. Fuel is supplied to the networks by road (tanker) or sea (ship) and the use of local storage. The same billing and settlement processes is applied as for the main GB networks, including caps on charges based on mainland network connections.
Licensing	Operated by SGN, a licensed gas distribution network
Key take-aways	• Despite physical separation from main gas networks, these are treated as part of single GB gas system – including Stornoway's system, which uses a different fuel. • Rules for switching and connections are the same as for user on the wider network, as is billing. • Small hydrogen networks could be run on exactly these principles, including development and operation by regional GDNs. However, the rules are currently used for small networks so there may be unintended consequences if they are applied at scale. This may necessitate an upper threshold on the scale of networks these rules can be used.
Relevant *Commercial Configuration*(s)	Directly relevant to #3 on pipelines and system operation, also to #2 with regards to shipping fuel to users and local storage arrangements

3.2.5 Independent water networks systems

Here, we discuss small independent water and wastewater networks. These are typically installed on new-build estates – both domestic and non-domestic – and form a key element of competition in a largely non-competitive sector. Note that there are two levels: "self-lay" providers, which build networks and then hand these over to the incumbent to operate, while here we discuss providers who build and operate networks.

Large water and sewerage companies (WASCs) are not discussed in this report. As large, monopoly-regulated network companies, key learnings are covered under the electricity and gas section.

Key take-aways

Dedicated licenses permit onsite treatment of water and wastewater but also interconnection with wider water systems.

Third party access rules have been instated for non-household customers.

The charging methodology for independent systems relies on discount to charges of regional water company.

Commodity and network costs are typically bundled from a single provider.

3.2.5.1 Ownership

Networks are owned by various “small water and sewerage undertakers”, which are licensed by sector regulator Ofwat. Some are non-regulated business spun off from regulated entities (e.g., Severn Trent Services) or other infrastructure companies (Leep Networks), while others are fully independent.
The regulatory regime is known as New Appointments and Variations (NAV) as the incumbent water company’s region is altered to exclude the relevant area and the licensed party is newly appointed to provide services in that region.

3.2.5.2 Operation

In terms of fees, NAVs must keep charges at or below the cost of the regional incumbent’s charges. Therefore, most simply peg their charges to the same level, or to a discount to this level.

Most operators will purchase bulk water or wastewater services via a connection to the wider regulated networks, with the operator only operating the local pipework, pumping stations and other network equipment. This allows operators to manage their risk level much better than building local water and wastewater treatment works.

However, there is an option for NAVs to undertake full or partial treatment of water and wastewater. The most common route is for ground water (e.g., rainfall on roofs and tarmacked outdoor space) to be receive the limited treatment required and discharged into the local environment, or for pre-treatment of trade effluent before discharging into the sewerage system[40].

As well as taking over the duties to supply water and sewerage services to consumers, the NAV will take on the environmental protection duties of the incumbent. Reluctance to take on these onerous duties keeps NAV areas relatively small.

3.2.6 Access

There is no third-party access to these networks for most customers, as there is no competitive water market for domestic customers. For non-domestic customers, who are competed for, water retailers’ access these in the same way as wider customers. They can purchase bulk water supplies from incumbent WASCs on the same terms as NAV operators or procure these from NAVs on a negotiated rate. Broadly, however, competition in the entire water sector is extremely limited and contractual arrangements are therefore standardised and simplified in this market.

The commercial arrangements and key takeaways for independent water networks are summarised in Table 6.

[40] Under the GB water charging principles, trade effluent is charged according to the Mogden formula which increases charges according to solid matter and biological treatment requirements, so relatively cheap treatment like a settling pool or reed-bed re-treatment can be highly economic.

Table 6: Commercial arrangements for independent water networks

Sector	Independent water networks (NAVs)
Arrangements	NAVs must keep charges at or below the cost of the regional incumbent's charges. Most operators purchase bulk water or wastewater services via a connection to wider regulated networks, with the operator only operating the local pipework, pumping stations and other network equipment. As well as taking over the duties to supply water and sewerage services to consumers, the NAV will take on the environmental protection duties of the incumbent. Reluctance to take on these onerous duties keeps NAV areas relatively small.
Licensing	Networks are owned by various "small water and sewerage undertakers", which are licensed by sector regulator Ofwat. Some are non-regulated business spun off from regulated entities (e.g., Severn Trent Services) or other infrastructure companies (Leep Networks), while others are fully independent.
Key take-aways	• Dedicated licenses permit onsite treatment of water and wastewater but also interconnection with wider water systems. • Third party access rules have been instated for non-household customers. • The charging methodology for independent systems relies on discount to charges of regional water company. • Commodity and network costs are typically bundled from a single provider.
Relevant *Commercial Configuration*(s)	Directly relevant to #3 on pipelines, also provides example of vertical integration

3.3 Energy storage systems

In this section we look existing gas and electricity storage models for grid-connected assets.

3.3.1 Grid-scale gas storage

Gas storage has a particular role in the UK in providing both a level of security of supply and system resilience and because of this the operatorship of gas storage facilities has certain requirements as defined in the Gas Act 1986. These requirements ensure independent operation and require open third party access.

Key take-aways

Pricing of capacity relies on liquid spot prices which provide visibility of value to users.

But this makes revenue for storage operators uncertain and prevents investment on building and maintaining assets.

Third party access requirements are well defined, based on booking capacity rather than volumes. Users set their prices with reference to value seen in liquid wholesale markets.

Exemptions allow operators to retain their own capacity from the market.

3.3.1.1 Ownership

Ownership of gas storage facilities is not restricted excepting, under section 11A[41] of The Gas Act 1986 that any owner operates, maintains and develops the facility economically and maintains sufficient financial resources to enable it to comply with the Act.

The independence of gas storage facilities is cited under section 8R[42] of the Act where the operator must refrain from producing any gas in the UK and refrain from the supply, transportation, or sale of gas unless it is necessary for the efficient operation of the storage facility. In addition, where the ultimate corporate ownership of the facility has subsidiaries that do supply, transport, or sell gas that the corporate owner maintains a robust system of Chinese Walls and separation, including the independence of senior managers, and writes an annual report to Ofgem stating its compliance.

3.3.1.2 Operation

For offshore facilities, the licensing authority is the North Seas Transition Authority although a Crown lease issued by The Crown Estate or Crown Estate Scotland as appropriate is also required. For onshore assets the licensing authority is Ofgem. Both onshore and offshore operators must comply with all health and safety regulations as described in section 2.3.2 and hold a gas transporters licence from Ofgem, that allows for gas to be conveyed through pipes to any pipeline system operated by another gas transporter. For some facilities however, an exemption for a gas transporter licence may be applicable if the length of the pipeline between the store and any other pipeline system is less than 16.093km[43] in length and certain conditions on informing Ofgem on the size and flow rate capabilities of the facility are met[44]. There is also a requirement for a Network Entry Agreement between the gas storage and transport system operators, that describe the T&Cs including minimum and maximum gas specifications; delivery and off-take rates and how, when and by which means flow notifications are communicated.

From a user to the gas storage operator perspective, the user makes timely nominations to the storage operator, usually by electronic means on the volume, represented as an hourly flow value, stating the direction of flow (either injection or withdrawal) and the start and end times of the flow. The storage operator then aggregates all flow nominations from all users, decides on how best to fulfil the requirement and provides a flow notification to the gas transport system operator on this decision.

3.3.1.3 Access

The UK abides by a negotiated third party access (nTPA) regime, as defined under section 19B[45] of the Gas Act whereby through standard published non-discriminatory Ts&C's any applicant can negotiate in good faith access to the storage facility subject to capacity availability. Under the nTPA regime, where the operator and applicant cannot reach an agreement, the applicant may refer to Ofgem for direction. Europe, on the other hand mostly abides by a regulated third party (rTPA) access regime where access is determined by auction.

A minor facilities exemption is available to assets upon application where Ofgem is satisfied the facility is not technically or economically necessary for the operation of an efficient gas market. Exemptions to third party access conditions and asset independence can be sought. For TPA exempt facilities, operators can still

[41] https://www.legislation.gov.uk/ukpga/1986/44/section/11A
[42] https://www.legislation.gov.uk/ukpga/1986/44/section/8R
[43] The exact origin of this requirement is unknown but as a reference the Rough offshore gas facility is approximately 29km from the Easington terminal
[44] https://www.legislation.gov.uk/uksi/2011/232/part/2/made
[45] https://www.legislation.gov.uk/ukpga/1986/44/section/19B

offer access to third parties although there is no recourse should the operator and applicant not reach an agreement. A list of all gas storage facilities[46] is published annually by Ofgem and it is noted that all current gas storage facilities in the UK bar SSE's Hornsea gas storage facility hold such exemptions.

Through the TPA regimes access to the facility is offered through three capabilities with each expressed in energy terms:

1. The hourly rate at which gas can be put into the facility (injection capacity)
2. The hourly rate at which gas can be taken out of the facility (withdrawal capacity)
3. The daily volume that can be stored (space capacity)

Operators then make up combinations of the above into products (bundled products) but can also offer individual capabilities through unbundled products. A full bundled product ensures a user can inject, store and subsequently withdraw gas from the storage facility whereas as an example a user that purchases unbundled firm space must then purchase injection capacity or purchase gas in store to utilise the space. The transfer of gas in store is usually an arrangement between two users and storage operators must facilitate the transfer of gas in store between users ensuring non-discriminatory access.

Each product can be offered through a guaranteed firm service or through interruptible mechanisms. For each product clear terms are provided including for interruptible services sufficient details and rules that govern when interruptible services can be curtailed and what happens if interruptible services are curtailed. The TPA regimes also allows users to become a customer of the facility but not necessarily become an active user. Here the non-active customer has access to asset operational communications and agrees to provide sufficient credit cover to pay for services should they become an active user, through the purchase of interruptible services at short notice for example.

To ensure all capacity has been offered to users, the storage operator will calculate the total volume of the three capabilities and then package up products such that all of the capability is made available. This means that any capability left is offered as an unbundled product. For depleted oil and gas fields the space component may change during the year due to in tank pressure considerations and so the operator will look to continuously monitor and access this component and thereafter offer unbundled space capacity as and when any additional quantity is assured.

To prevent hoarding of capacity and to maintain an efficient operation of the facility non-exempt facilities also operate a use it or lose it (UIOLI) policy. This ensures that any under nominated or spare capability can be offered to all users including the operator although it is usually prudent to offer the capacity to customers in the first instance. Whereas under normal scenarios visibility of spare capability only materialises within day the storage operator may offer interruptible products to satisfy customer appetite and or short term capabilities.

Users of gas storage are usually looking to price arbitrage the difference in prices between time periods, buying gas and injecting into storage when prices are seen as low and selling and withdrawing gas for storage when prices are deemed high. Alternatively, users are using storage to modulate the difference between time periods of production and periods of consumption and utilise the store as a means to ensure security of supply to end users.

The commercial arrangements and key takeaways for grid-scale gas storage are summarised in Table 7.

[46] https://www.ofgem.gov.uk/publications/gb-gas-storage-facilities-2022

Table 7: Commercial arrangements for grid-scale gas storage

Sector	**Grid-scale gas storage**
Arrangements	Owned by parties unbundled from gas production and networks, though parties without an exemption must provide third party access (TPA). This is negotiated between parties, although the regulator can intervene if there is no agreement, and access is generally provided on a capacity basis, though some operators also offer services or trade themselves on a volumetric basis.
Licensing	Licensed by Ofgem or (for offshore facilities) the North Sea Transition Authority
Key take-aways	• Pricing of capacity relies on liquid near-term and forward dated wholesale prices to provide transparency to users. • As such, establishing a business case for such assets is reliant upon ensuring a regular revenue or value stream through suitable contractual arrangements and/or a means by which to hedge basis risk between the price at which gas is injected and that at which it is withdrawn. • Third party access requirements are well defined, based on booking capacity rather than volumes. Users set their prices with reference to value seen in liquid wholesale markets. • Exemptions allow operators to retain their own capacity from the market.
Relevant *Commercial Configuration*(s)	Relevant to all *commercial configurations* as example of independently operated capacity-traded storage, including storage on a seasonal.

3.3.2 Electricity storage (short duration)

Short-duration electricity storage in GB includes – at various scales and technology readiness levels – Li-ion, vanadium-flow and other novel battery chemistries, and kinetic storage, though Li-ion batteries are by a wide margin the most developed technology-type. Initially, assets were usually 1-hour or even sub-1-hour duration, but the paradigm is moving towards 2-hour duration. Some developers are starting to look at 4-hour duration for future projects, as technology costs fall.

The technology and business case is increasingly well-understood, with even risk-averse banks now becoming confident to invest in short-duration storage, and market growth is expected to be rapid over the next 2-5 years.

Key take-aways

Historic business model based on providing short-duration services on long-term contracts priced at different levels to system operator, including capacity (standby) and volumetric services to provide security of supply.

Moving to an arbitrage model, relying on temporal changes in short-term commodity wholesale markets.

Trading conducted on a volumetric rather than capacity basis though some operators reviewing capacity options.

Increasingly automated dispatch of services to cover changes in demand 24/7.

3.3.2.1 Ownership

Development and ownership of short-term electricity ownership is conducted by a range of bodies on a range of models. The most common are described below:

- Developer-owner-operator
  - This model sees a developer initiating a project, securing planning, grid-connection and other permissions, seeking investment and then constructing and commissioning an asset.
  - This party then operates the asset in the market on an ongoing basis.
- Developer-owner
  - This model is similar to the above, but at some point – usually when risk levels are changing either post-approvals/ pre-construction, or just after commissioning – selling it to another party in the below owner categories.
  - This enables the developer to release capital to concentrate on its strengths in developing new assets.
- Investor-owner-operator
  - This model sees the investors taking over a project, usually at the point of a risk-level change, and then completing and operating it over the long-term.
  - This model is relatively uncommon in storage assets, as few investors have the expertise in energy markets to dispatch assets day-to-day.
- Investor-owner
  - This model, as with the above, sees the investor take over an asset at a risk-level change and owns it over the long-term, but brings in a specialist provider to operate it on a day-to-day basis.
- Vertically integrated
  - A large utility (energy supplier or generator) will either develop an asset end-to-end or buy it from a developer at a risk-level change.
  - The utility will then operate the asset as part of its overall portfolio, for example to manage imbalance over the short term or to improve value from its renewable generation fleet.

- This model appears to be becoming more common, and smaller players are also looking to procure battery capacity to manage imbalance and trading positions even down to the scale of local energy markets.

3.3.2.2 Operation

The original short-duration storage assets were largely supported under business cases relying on balancing services revenues; for example, some of the earliest projects were the 200MW of storage supported under the Enhanced Frequency Response tender in 2016, which led directly to £100mn investment and kickstarted the battery market in GB.

More recently, the forecast volume of assets in GB would swamp balancing services need. This need is around 3-4GW maximum, whereas 3.3GW of battery capacity was successful in 2022's Capacity Market (CM) auction alone. Storage developers have therefore moved to a new model, which stacks a baseline of CM revenues with wholesale arbitrage and Balancing Mechanism (BM) revenues to create a viable business case. This relies on the high levels of liquidity in GB electricity trading over a number of time-horizons: years or seasons ahead, day-ahead, and intraday, to allow assets to access value by arbitraging the difference between electricity wholesale prices across the day: low prices typically occurring during overnight demand lulls and high prices typically occurring during the morning and evening demand peaks. Importantly, these models are largely merchant, with perhaps 5-10% of lifetime revenues arising from the relatively "certain" CM payments, while around 45-50% arise from wholesale arbitrage and a similar amount from BM revenues, both of which are only accessible on a very short-term basis and are merchant revenue streams.

Operation is often conducted by developer-owner-operators (which secure funding from third party investors to build assets). Other common models include developer-owners, who build assets and then use a third-party aggregator/optimiser service provider to conduct day-to-day trading and dispatch for the assets.

In the latter case, there would typically be a contract for optimisation of the asset between the owner and an optimisation service provider (typically an aggregator). This contract could last anything from 6 months to the lifetime of the asset (perhaps 15 years), but we would expect contracts to last around 1-2 years before re-tendering. There is a competitive pool of aggregators available to choose from.

Some models would see the aggregator taking on all costs and liabilities, returning either a fixed value or a share of profits to the owner, while other models would see the owner retaining all costs and revenues and simply paying the aggregator a fee for its services dispatching the asset (this could again be flat or a share of profits).

3.3.2.3 Access

As these assets are operating on a merchant basis, there is no third-party access to the assets to improve system operation, nor is there an obligation for operators to help the system. However, economic incentives do align with this behaviour, with power prices to charge assets lowest during demand lows and to discharge revenues highest during demand peaks.

The same is the case for BM participation, although this is "accessed" by National Grid Electricity System Operator (ESO), which will dispatch units bid into the BM as it requires to maintain system security.

There are some further exceptions. Firstly, units with CM contracts are required to be exporting at their de-rated capacity during CM events. Second, some assets will bid into balancing services markets, which increases revenue certainty in exchange for (generally) lower revenues; again these services are dispatched by ESO.

Finally, some players are exploring new (to electricity) contractual paradigms whereunder battery capacity is sold over the short or long-term, to be dispatched by a third party. This party might wish, for example, to operate the battery to manage its imbalance position. This is more similar to gas storage operation. There is no obligation for storage providers of any size, however, to enter these contractual arrangements.

3.3.3 Electricity storage (Long duration)

The primary long-duration storage technology in GB is pumped hydro, of which there are four units ranging in size between 300MW and 1.7GW. Several additional assets are under development, including a 450MW unit and a 1.5MW asset, as well as increasing the size of the Cruachan 400MW site to 1GW. However, no new capacity has been added in over 40 years, and development timelines are extended, with asset-build typically lasting 4-6 years.

Typical storage duration is six to seven hours. New long-duration storage technologies include gravity storage and compressed or liquified air storage, though these are still at early technology readiness levels. Long-duration storage tends to have a much higher capex than short-duration, but also much longer useful lifetimes. For example, a pumped hydro asset might last for 100 years or more with only occasional refurbishment, while compressed air storage could last for 40 years. This compares to li-ion storage, which might last for 12-15 years before requiring complete replacement.

Key take-aways

More analogous to gas storage in terms of reliance on liquid forward prices to provide visibility of value to users and how the lack of long term revenue certainty prevents investment on building and maintaining assets.

Much more expensive to build than short-duration, therefore less buildout under merchant models – most current operators are using vertical models.

Same licensing/ operation regime and revenue streams as short duration electricity storage.

Long lifetime and large sizes requires consideration of wider market dynamics and holistic system benefits.

3.3.3.1 Ownership

The ownership models for long-duration electricity storage assets are the same as those for short-duration storage. However, due to the size and cost of the assets, which is much higher than short-duration storage, the vertically integrated model is by far the most common.

The four extant pumped hydro assets are owned and operated by large, vertically integrated utilities: Drax, SSE and Engie. One of the new assets is being developed by SSE, while another is in development by an independent player – though it is likely that this party will exit the project at a later stage and sell to an investor or vertically integrated company.

The new wave of technologies are of more modest size than previous large pumped hydro units, often being modular. They appear to be siting initially in behind-the-meter roles and given the characteristics of the technologies, which often create or consume heat, are being paired with heat sources or demand in arrangements such as heat networks. This has led to substantial Local Authority involvement and joint ownership of projects, with resultant complex contractual arrangements.

3.3.3.2 Operation

Like short-duration storage, long-duration is operated on a merchant basis in the wholesale day-ahead and intraday markets, and the balancing mechanism, providing value from energy arbitrage. Most assets will also secure CM contracts and may opt for some element of balancing services revenues as well. These provide more certainty on revenues compared to energy arbitrage, though contracts are still very short term compared with the lifetime of assets.

Given the vertically integrated nature of existing long-duration storage, the same operational model of an owner using a third-party aggregator to operate assets is considered unlikely, with the large utilities having the knowledge and resources in-house to trade and operate these as required.

3.3.3.3 Access

As with short-duration storage providers, there is no obligation to provide third-party access to assets. These are traded on a merchant basis to – primarily – earn revenues through time-arbitrage of energy. When operated by large vertically integrated parties, there will also be a significant opportunity to use the assets to provide imbalance management and mitigate the impacts of generation and demand forecasting errors. This provides an additional revenue stream/ cost mitigation opportunity which is not available to smaller parties.

Where assets are located behind the meter, contracts will generally specific a requirement to provide services to onsite consumers first, for example to manage limited network connections to private wire networks. This can constrain the activities of the asset, which will be required to meet certain states of charge in order to guarantee service provision and therefore may not be able to take advantage of the best opportunities in the wider market. This restriction would be compensated in other ways, for example through a “free” grid connection (paid for by the site operator) or by a regular payment.

The commercial arrangements and key takeaways for short duration storage are summarised in Table 8.

Table 8: Commercial arrangements for short duration storage

Sector	Elec – short duration e.g. battery	Elec – long duration e.g. pumped hydro
Arrangements	Unbundled from networks but sometimes integrated with generation and/or supply portfolios, or wider aggregation pools. Revenues arise from balancing services and, increasingly, wholesale arbitrage on a merchant basis. Increasingly commonly seen co-located with renewable generation.	All existing assets are owned by large, vertically integrated utilities. Operated on much the same models as short-duration storage, but with longer durations, much longer operational lifetimes, and much higher capital costs to build. No new build in ~40 years due to the lack of revenue certainty, but some assets are once again in development.
Licensing	Licensed as electricity generation by sector regulator Ofgem; exemptions exist for assets under 50MW, although licensed generators do not pay final consumption levies and storage is therefore incentivised to obtain a licence.	
Key take-aways	• Historic model based on short-duration balancing services on long-term contracts, including capacity (standby) and volumetric services to provide security of supply. • Moving to an arbitrage model, relying on changes in short-term commodity markets. • Traded on a volumetric basis, though some operators reviewing capacity options. • Increasingly automated dispatch of services to cover changes in demand 24/7.	• More analogous to gas storage. • Much more expensive to build than short-duration, therefore less buildout under merchant models – most current operators are using vertical models. • Same licensing/ operation regime and revenue streams as short duration electricity storage. • Long lifetime and large sizes requires consideration of wider market dynamics and holistic system benefits.
Relevant *Commercial Configuration*(s)	Relevant to all *commercial configurations* as example of independently operated volume-traded storage.	Relevant to #3 and #3b as an example of independently operated volume-traded storage at the larger (though not seasonal) scale.

3.4 Electricity interconnectors

An electricity interconnector is a physical connection between two independent electricity markets. These can be overland, but are often – and from GB, exclusively – undersea. The typical technology currently used is High Voltage Direct Current (HVDC), which reduces losses for transmission over long distances and allows control of the amount of power allowed to flow across the asset.

Interconnector traders earn revenues based on the locational arbitrage between the two markets at either end of the interconnector, known sometimes as congestion revenues. The potential for locational arbitrage will typically cause prices in the two markets to converge over time as market opportunities are developed.

Interconnection from GB has increased markedly in recent years, from 4GW in 2012 to 7.4GW currently and expected to reach nearly 16GW by 2025, under the cap-and-floor regime which we discuss in this section.

Key take-aways

Operated on a system selling capacity to the market system, not selling volumes.

Profits from locational price arbitrage.

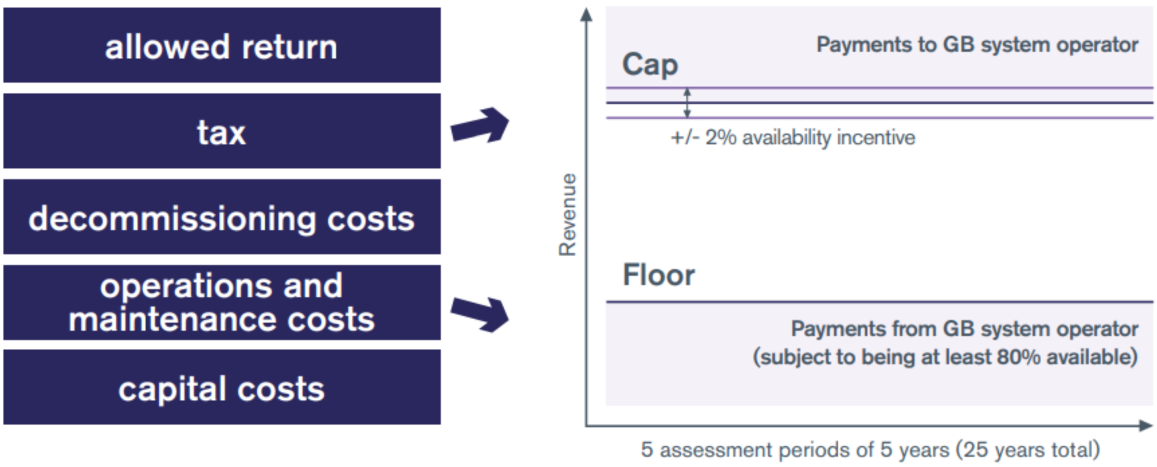
Cap-and-floor mechanism might be suitable for hydrogen assets.

3.4.1 Ownership

Interconnectors are owned by a range of parties, including National Grid Ventures (the non-regulated arm of National Grid), foreign Regional Transmission Owners (RTOs) and investor groups. New interconnectors are in general under the cap-and-floor regime[47], which provides a minimum level of income certainty to protect investors, in return providing a maximum level of income to protect consumers.

The floor payment requires meeting an 80% availability target, while the cap increases ±2% depending on availability. The regime endures for 25 years, to cover in repayment of the initial investment. The regime is reviewed on a 5-year cycle to ensure that payments remain appropriate. Elements included in assessment of suitable cap and floor prices include capital costs, operational and maintenance costs, decommissioning costs, taxes, and allowed returns. Revenues included are the sale of capacity, capacity market payments, and provision of balancing services. Insurance and constraint payments are also counted.

Figure 1: Cap-and-floor building blocks



Source: Ofgem

[47] https://www.ofgem.gov.uk/sites/default/files/docs/2016/05/cap_and_floor_brochure.pdf

3.4.2 Operation

Operation of interconnectors is covered by a range of contracts and requirements. These include the Harmonised Access Rules, participation agreements and contractual frameworks; although each interconnect publishes its own versions and users are required to sign up to each interconnector independently, these are broadly standardised. Once accredited to the interconnector, the allocation platform (which holds auctions for allocation of capacity), the nomination platform (used to nominate capacity).

3.4.3 Access

Interconnectors with a cap-and-floor arrangement are required to provide access to the interconnector to all users – the owner does not itself trade across the interconnector but earns rental revenues by auctioning the capacity to the market. Access is provided via online auction platforms. The users who win auctions are responsible for trading energy in the national markets on both ends of the interconnector[48], in order to then dispatch the interconnector itself as a conduit between these markets.

In addition to providing trading and locational price arbitrage between the interconnected markets, interconnectors are now considered to offer electricity security of supply to the system, being able to bid into the capacity market. Successful interconnectors will need to import at their de-rated capacity (which ranges widely from under 50% to over 80%) during the full four-hour term of a capacity market event, if an event were to be called. De-rating factors are adjusted yearly and given the role of the interconnector as a conduit rather than a power producer – and therefore being unable to guarantee power provision – are expected to fall in general.

The commercial arrangements and key takeaways for interconnectors are summarised in Table 9.

Table 9: Commercial arrangements and key take-aways for interconnectors

Sector	**Interconnectors**
Arrangements	Owned and operated by independent parties including unregulated arms of regional transmission owners, or by investor groups. Under the cap-and-floor business model, minimum annual income is guaranteed but is also restricted to a maximum level. Trading is conducted by third parties who buy capacity on the interconnector in regular auctions; these third parties earn revenue based on the price differential between the markets at the time of flowing power.
Licensing	Licensed by Ofgem to connect to the system and operate
Key take-aways	• Operated on a system selling capacity to the market system, not selling volumes. • Profits from locational price arbitrage. • Cap-and-floor mechanism might be suitable for hydrogen assets.
Relevant *Commercial configuration*(s)	#3 and #3b, with regards to connecting separate systems, potentially providing a configuration for joining-up clusters in the mid-term.

[48] Before Brexit, implicit trading and capacity allocation was conducted, but this is no longer the case.

3.5 Refined petroleum T&S

3.5.1 Road fuel

In the UK, over 50% of oil is used for road transport purposes and nearly 30% of final energy demand arises from moving people and goods on the roads – around 46bn litres a year. The UK Market both imports refined fuels and refines crude oils into fuel domestically, as well as having an emerging market for bio- and synthetic low carbon fuels. Although it is not generally well-known, a range of pipelines for various grades of transport fuel exist in GB, transporting around 30mn tonnes of product a year. Fuels are also transported by ship, rail, and road freight.

In additional to fossil petrol and diesel, the industry is required by the Road Transport Fuel Obligation (RTFO) to include a share of bio-fuels in the fuel mix. Small Liquid Petroleum Gas (LPG) and Compressed Natural Gas (CNG) markets are also evolving, with these fuels supplied both on the same sites as existing petrol forecourt, on adjacent sites, or on completely separate sites. These fuels are both fossil and bio in nature. Transportation and storage models appear to be consistent with wider fossil fuel practices.

Key take-aways

Tanker deliveries – tanker fleets either owned or licensed from third party.

Highly competitive market both to source fuel and for end-users to purchase fuels.

Large incumbents mostly moved away from supplying to the independent market, replaced by third parties.

Long-term insufficiencies in investment in skills such as HGV/ tanker drivers.

3.5.1.1 Ownership

Transportation pipelines are owned by various international oil companies. These pipelines are capable of transporting different fuels in batches, without mixing them. However, these are liquid fuels, and the pipelines are unlikely to be suitable for repurposing for hydrogen transport. The privately owned oil product (road fuel and aviation fuel) pipelines are:

- CLH Pipeline – formerly UK Government, now CLH
- UK Oil Pipeline – Shell, BP, Valero, Total
- Mainline Pipeline System – Esso, Valero, Total, Shell, ExxonMobil
- West London Pipeline – BP, Shell, Valero, Total
- Esso Pipeline – Esso
- Walton-Gatwick Pipeline – BP, Shell, Valero
- Fina-line – Total

For the majority of fuel users, which are not connected to these pipelines, delivery is carried out by tankers, which carry up to 40,000 litres of fuel. These tankers are owned by a large variety of providers, including operators of major refineries and/or fuel forecourts, and independent parties.

The around 8,000 forecourts in the UK are owned by a variety of parties and it is not immediately apparent to users who owns any individual forecourt, as some operators offer a franchising models for some stations. This further increases the diversity of the market, contractual arrangements, and pricing models.

Figure 2: Map of crude oil (red) and refined product (blue) pipelines in GB

3.5.1.2 Operation

Petrol filling stations can be independent or owned by fuel companies. Smaller, one-site dealers have faced the biggest pressure on their business models. Independent petrol filling stations will have contracts with petroleum product suppliers.

In terms of transportation, this is generally conducted by road tanker fleets over the last mile. Some forecourt operators own and operate their own fleets (e.g., Shell, BP), some licence third party fleets (e.g., Sainsbury's) and some use third party providers (e.g., independent providers). Recent years have demonstrated a shortage of qualified drivers in the industry, both in terms of general HGV drivers but also particularly tanker drivers. Regulatory anomalies have also been reported, such as a restriction preventing hydrogen-fuelled tractor units towing hydrogen tanker units.

3.5.1.3 Access

Dispensing premises such as petrol stations must have storage certificates[49] that are granted by the Petroleum Enforcement Authority (PEA). Depending on the ownership model for the forecourt, they may or may not have the capacity to flexibly access different fuel suppliers – independent retailers are likely to, while others cannot.

The commercial arrangements and key takeaways for petrol and diesel deliveries are summarised in Table 10.

49 https://www.hse.gov.uk/fireandexplosion/owner-petrol-station.htm

Table 10: Commercial arrangements for petrol and diesel deliveries

Sector	Petrol and diesel deliveries
Arrangements	Deliveries to forecourts are made by tanker fleets, with forecourt owner/ operators managing storage and deliveries. Various operational models – vertically integrated (e.g. Shell), chains (e.g., supermarkets) and independent – exist and these procure transport differently, with some owning tanker fleets, some leasing/ licensing these on long-term agreements and some taking service from independent or fuel-refinery providers. In addition to tanker fleets, long-distance transfer of fuel between depots is carried out by pipelines, which can supply various fuel types (petrol, diesel, aviation fuels) in batch deliveries.
Licensing	Not currently licensed, but is controlled by planning and permitting, and by health & safety requirements and certified by the local Petroleum Enforcement Authority (often the local authority or local fire brigade).
Key take-aways	• Tanker deliveries – tanker fleets either owned or licensed from third party. • Highly competitive market both to source fuel and for end-users to purchase fuels. • Large incumbents mostly moved away from supplying to the independent market, replaced by third parties. • Long-term insufficiencies in investment in skills such as HGV/ tanker drivers.
Relevant *Commercial Configuration*(s)	Directly relevant to #1, #2, as a model of commercial arrangements for small-scale sites.

3.5.2 Aviation fuel

Aviation fuel in the UK is provided by a variety of different companies, transported via pipelines or tankers, and delivered at airfields by both third parties and companies with their own production arms. Aviation fuel demand is typically in the region of 10mn tons annually, of which approximately half is imported, and half refined domestically.

Key take-aways

Several major airports are connected by pipeline to refineries or terminals for bulk supply, but majority rely on tanker truck deliveries.

Aviation fuel industry is fully competitive, with a large number of providers and airport operators to choose from, and private ownership at all parts of the value chain.

The industry is therefore comparatively lightly regulated, without the strict licensing and price controls of the energy sector.

3.5.2.1 Ownership

Aviation fuel is supplied by a variety of private companies, most of which are major names in petrochemicals: BP, Shell, Total, and Chevron, among others. These companies provide fuel to airports either by pipeline (where available) or tankers. Three major onshore pipelines are used to move aviation fuel in bulk: the Walton-Gatwick Pipeline owned by BP, Shell, and Valero; the Fina line owned by Total; and the Southampton-London Pipeline owned by Esso, all of which serve London airports. There is also a pipeline owned by Essar Oil that supplies Manchester Airport.

Storage of aviation fuel at each airport appears to be co-owned by the fuel operators at those airports and the airports themselves. Airlines then contract with "into plane" companies which operate vehicles to move fuel from storage to the planes; in the UK the service providers are designated by the airport operators, with larger airports having a range of providers for airlines to choose from.

3.5.2.2 Operation

Airlines buy their fuel from the available operators at the airports they operate from. These fuel operators may be third parties, or vertically integrated with production companies that supply the fuel to airports. Airlines will have standing contracts with their own operators at the airports they fly out of, while private aviation is more likely to buy from fuel operators on an ad hoc basis. From anecdotal evidence it appears to be common practice for airlines to be judicious in responding to fuel prices at different airports, e.g. carrying extra fuel to avoid refuelling at the destination airport if fuel is cheaper at the home airport. We have seen some long-term deals for fuels, particularly regarding emerging sustainable aviation fuels, but how pricing is set has not been specified in public-facing documents.

3.5.2.3 Access

Fuel operators at airports operate on a competitive basis, with most airports appearing to have multiple fuel operators available to choose from and contract with. Airports served by pipelines directly linked to refineries will have much more limited choice and will be subject to commercial negotiations with the refinery operator, but the capacity for fuel to be delivered by tanker always provides them with an alternative supply to strengthen their negotiating position and prevent their provider abusing its position.

The commercial arrangements and key takeaways for aviation fuel are summarised in Table 11.

Table 11: Commercial arrangements for aviation fuel

Sector	Aviation fuel
Arrangements	Airlines buy their fuel from the available operators at the airports from which they operate. These fuel operators may be third parties, or vertically integrated with production companies that supply the fuel to airports. Airlines will have standing contracts with their own operators at the airports they fly out of, while private aviation is more likely to buy from fuel operators on an ad hoc basis.
Licensing	Aviation fuel is supplied by a variety of private companies, which are not licensed. Three major onshore pipelines are used to move aviation fuel in bulk, owned by parties or consortia. The industry is competitive, with fuel operators having a wide choice of suppliers.
Key take-aways	• Several major airports are connected by pipeline to refineries or terminals for bulk supply, but majority rely on tanker truck deliveries. • Aviation fuel industry is fully competitive, with a large number of providers and airport operators to choose from, and private ownership at all parts of the value chain. • The industry is therefore comparatively lightly regulated, without the strict licensing and price controls of the energy sector.
Relevant *Commercial Configuration*(s)	Relevant to #2 as a model of long-term, large-scale arrangements with multiple parties in the producer, transport and supplier roles.

3.5.3 Maritime fuel

Bunkering, or the provision of fuel for maritime operations, is relatively small-scale in GB, compared to some international markets, but totalled over 2,000ktoe in 2021 (23.2GWh) according to BEIS' DUKES. It is conducted on a number of scales, from very small scale deliveries of dozens of litres to domestic and pleasure craft, to thousands of tonnes for merchant shipping. This has led to a range of models being implemented for trading and supply, of which we cover a range of standard models here.

Key take-aways

Bought as a delivered product – fuel and shipping together.

Highly competitive market from third party deliverers.

Many and varied storage providers.

3.5.3.1 Ownership

Most deliveries are conducted by third parties under open commercial contracts; typical contract length is for one delivery. Even major fuel consumers appear to utilise the open marketplace for fuel procurement; for example, the Ministry of Defence secures deliveries regularly via the market (though through a framework).

These third parties are largely independent of both the fuel producers (e.g., refineries) and consumers, mostly owning a fleet of fuel-transportation vehicles and vessels, buying fuel from refineries and selling directly to consumers. Some operate small storage assets at their depots and at key demand locations, in order to ensure that supply is available and to hedge pricing.

In addition to transportation providers, ports are a key fuel source for users; these commission deliveries to their local storage assets[50] and then sell on to demand, either directly "at-pump" or by transferring fuel across the port on local delivery vehicles. Alternatively, these in-port facilities can be operated by third-parties including both petrol-chemical players such as BP and Total, with large refinery businesses, and the same sort of independent parties as provide fuel deliveries.

Note that some petrol-chemical players do offer deliveries directly to customers. This appears to mostly be at the larger scales.

3.5.3.2 Operation

Deliveries are made in one of two ways: from small-scale local storage, akin to a commercial petrol station; or via special deliveries from road tankers, in-shore bunkering barges, rail tankers, or in some cases at-sea underway replenishment from ocean-going oilers.

The primary difference is of location, with the former carried out at a location pre-set by the fuel provider, while the latter sees the fuel brought to the user. This is attached to scale to a certain extent, with larger offtakers of fuel likely to receive fuel where they are, while smaller offtakers will go to the fuel location.

Cost is also a driver; while the models we have examined rarely have explicit delivery fees, these fees are factored into unit prices. Particularly where commercial vessels are concerned, the opportunity cost of diverting to reduce fuel unit prices may be higher than the additional costs of receiving fuel in the more convenient manner. This is explicitly the case for at-sea refuelling. Contracts are arranged to specify:

- The location, date and time of delivery, typically including a few hours of leeway and penalties for non-delivery.
- The quantity of offtake, with penalties for not being able to offtake the full order volume ±5% under a take-or-pay arrangement.
- The type and grade of fuel, often with reference to ISO grades.
- The metering operations, typically the responsibility of the provider.
- The relevant regulation, i.e., the International Convention for the Prevention of Pollution from Ships (MARPOL) regulations[51].
- The price and currency, with prices often fixed at point of ordering but may be set in reference to a market index price while currencies are generally local or US dollars.
- When title to the product changes, usually when it enters the offtakers tank and/or payment is made

[50] Which, at larger ports, can be of significant size

[51] MARPOL includes requirements to demonstrate how fuel has been consumed, in order to minimise the risk of this being dumped overside in cases where it has been accidentally contaminated or during tank cleansing

The contracts are standard for each party and broadly standard across the industry; membership bodies such as the Baltic and International Maritime Council (BIMCO) provide standard contracts[52] for use by members.

Fuel deliveries are covered under several sets of regulations – storage and transportation requirements are covered under hazardous materials regulations from the HSE. Fuel quality, for example sulphur content, and potential spillage is covered under MARPOL.

3.5.3.3 Access

Either method, fuelling at pump or delivery, is freely available to the market. Given a large number of players, there is significant competition for fuel delivery services. This leads to a liquid market with prices dependent on underlying wholesale prices. In fuel offtake services, however, there tend to be a relatively small number of players at any particular port – frequently only one. This constrains competition for smaller boats which do not have the offtake capacity to make ordering a tanker viable.

Some larger players with multiple vessels and well-known requirements may strike long-term contracts for delivery, in order to hedge their price exposure. For example, jack-up rigs (used to install oil and gas, and offshore wind, assets) may hedge their fuel demand at commencement of a contract, in order to protect themselves from a non-pass-through expense. This is relatively uncommon though, and for larger fleet operators, vessels often carry sufficient quantities of fuel for them to be able to hedge their demand by choosing which port, in which nation, to refill tanks.

The commercial arrangements and key takeaways for maritime fuel are summarised in Table 12.

Table 12: Commercial arrangements for maritime fuel

Sector	**Maritime fuel**
Arrangements	Deliveries mostly carried out under open commercial contracts for single deliveries, although some long-term arrangements are seen – mostly to de-risk/ hedge fuel purchasing for duration of a contract. There are many tanker companies which offer deliveries, both independent and vertically integrated with fuel production/ import, and an array of different storage providers, with refineries, tanker companies and ports all providing storage services. Delivery, storage and fuel is all incorporated into a single price, which is agreed prior to delivery.
Licensing	No licensing, strong health and safety and pollution controls including implementation of international protocols.
Key take-aways	• Bought as a delivered product – fuel and shipping together. • Highly competitive market from third party deliverers. • Many and varied storage providers.
Relevant *Commercial Configuration*(s)	#2, as a model of very short term, bundled arrangements for one-off deliveries of fuel, but which provide no long-term certainty.

[52] https://www.bimco.org/contracts-and-clauses/bimco-contracts/bimco-bunker-terms-2018

4 Summary of commercial arrangements in similar sectors

The suitability of similar sectors to the *commercial configurations* (summarised in section 3 of this Annex, and detailed further in the main report) is summarised in Table 13. This highlights the timeframes (early, growing, enduring) over which the sectors may be relevant.

Table 13: Applicability of similar commercial arrangements to the four commercial models

KEY:

	Highly suitable
	Interested learnings
	Not suitable
	Not applicable

		Suitability for H_2			
Sector	Key characteristics	*Commercial Configuration*	Early	Growing	Enduring
Gas transmission and distribution	• Heavily regulated monopoly networks model with complex rules • Will have key interactions with H_2 networks • Rules are well-defined but may be less suitable for developing fuel	**#1**			
		#2			
		#3			
		#3b			
Heat networks	• Lightly regulated, but subject to change under new rules • Users have choice to disconnect and choose own heat solution, but likely to be expensive	**#1**			
		#2			
		#3			
		#3b			
Independent power networks	• Monopoly network model, but level of licensing varies by size and connected parties • Often host own generation • Users have right to choose own supplier, but may be expensive if on a private network	**#1**			
		#2			
		#3			
		#3b			
Independent gas networks	• Regulated monopoly networks model with complex rules	**#1**			
		#2			

		Suitability for H_2			
Sector	Key characteristics	*Commercial Configuration*	Early	Growing	Enduring
	• Rarely feature own production • Functionally similar to gas transmission and distribution	**#3**			
		#3b			
Scottish Independent Networks	• Physically discrete small networks in Scotland that use LNG or LPG, with their own special rules • Feature storage but supplied via tanker • Otherwise functionally part of the GB gas system, so rules are highly suitable for H_2 • May be less suitable for application at large scale, however	**#1**			
		#2			
		#3			
		#3b			
Independent water networks	• Operates whole system • Commodity and network costs are typically bundled from a single provider • Operated under license and must charge at or below regional incumbent's charges	**#1**			
		#2			
		#3			
		#3b			
Gas storage	• Licensed operators are part of national system, relying on liquid markets e.g a market with many available buyers and sellers. Provides visibility to users but makes revenue uncertain • Well-defined third party access rights based on booking capacity • Owner must be unbundled from trading operations	**#1**			
		#2			
		#3			
		#3b			
Electricity storage	• Level of licensing varies by size • Large-scale long-duration storage more equivalent to gas storage. Short-term battery storage more reliant on within-day volatility • Business case heavily built around providing services to system, not simple price arbitrage	**#1**			
		#2			
		#3			
		#3b			

Sector	Key characteristics	Suitability for H_2			
		Commercial Configuration	Early	Growing	Enduring
Electricity interconnectors	• Operated on a system selling capacity to the market system, not selling volumes • Profits from locational price arbitrage • Cap-and-floor mechanism might be suitable for hydrogen assets	**#1**			
		#2			
		#3			
		#3b			
Road fuel	• Deliveries to users/retailers by tanker • Highly competitive market for both sourcing and purchasing fuel • Large incumbents mostly moved away from supplying to the independent market, replaced by third parties	**#1**			
		#2			
		#3			
		#3b			
Aviation fuel	• Deliveries mostly by tanker, but some airports have pipelines • Fully competitive, with a large number of providers and airport operators to choose from • Comparatively lightly regulated, with safety legislation but not licensing	**#1**			
		#2			
		#3			
		#3b			
Maritime fuel	• Fuel and shipping bought as a delivered product together • Highly competitive market from third party deliverers • Many and varied storage providers	**#1**			
		#2			
		#3			
		#3b			

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