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The future of gas
Transition to hydrogen in the gas grid

Introduction

Hydrogen is often seen as a key enabler of the Energy Transition. Analysis tends to focus on the technical and economic challenges around its production and use. But preparing for a widespread and efficient "hydrogen economy" will also require significant changes to the regulatory framework of any jurisdiction that already has a liberalised downstream gas industry, and it is not too early to start thinking about these.

Background

Heating accounts for nearly half of all energy consumption in the UK, and decarbonising heat is a critical requirement for meeting the Climate Change Act target for 2050. Natural gas (gaseous hydrocarbons, principally methane) supplies over two thirds of our heating (commercial and residential space and water heating). So the debate has begun about the future of the gas supply industry in GB and, in particular, the potential role of hydrogen as a zero-carbon fuel at the point of consumption, as a substitute for natural gas. Various demonstration/ proof of concept projects are already in early stages of development, such as the H21 Leeds Citygate and Hynet North West projects[1].

To date, discussions have largely focused on technical, safety, cost and (to some extent) funding issues, and possible "steady-state" models for a hydrogen system in the long term (for example, by 2050)[2]. This paper looks at the question how, in the transition towards such a long-term model, the current regulatory and commercial model for gas supply could accommodate the introduction of hydrogen.

Hydrogen can be produced from methane, by the process known as "steam reforming", which produces CO2 as a by-product. If this process is to be adopted, CCS (or CCUS, carbon capture use and storage) will need to be developed as a viable technology at commercial scale, to sequester the CO2 produced.

Hydrogen can also be produced by electrolysis of water, using electricity, although the technologies at this stage are relatively inefficient compared to steam reforming. There are doubts whether enough additional low-carbon electricity generation can be installed to make this technology viable (on its own) to produce the quantities of hydrogen needed to meet heat demand.

Biogases (produced by anaerobic digestion or process synthesis of renewably sourced feedstock or waste) will have a continuing role in a low-carbon gas supply system, but not (or not economically) on a scale to substitute for natural gas.

Both hydrogen and (on a transitional basis) natural gas may also play a part in decarbonising transport (road, rail, shipping) and reducing other harmful emissions, particularly from heavy transport. And the petrochemicals industries will represent an ongoing demand for certain amounts of natural gas hydrocarbons.

1 See: Leeds City Gate H21 and Hynet North West.

2 See e.g. Frontier Economics: Report for BEIS on Market and Regulatory Frameworks for a Low Carbon Gas System, March 2018; Hydrogen-in-a-low-carbon-economy November 2018, published by the Committee on Climate Change; and Hydrogen supply chain evidence base November 2018, prepared by Element Energy for BEIS.

Heat pump technology is currently the principal alternative for meeting heat demand without burning fossil fuels. Heat pumps use power (from renewable sources, in a low-carbon context) to extract heat from air or water, and deliver the heat as hot water or steam, through a heat network (serving several premises) or an installation at a single property.

The emerging consensus is that no one technology for heat will prevail on its own, and that (at least in the medium term of 20 to 30 years) a combination of different solutions will be deployed. A current view is that hybrid heat systems (combining heat pumps with hydrogen boilers to meet peak heat demands) might be a cost-effective option.

While there are parallels between the "greening" of electricity and gas, there is a fundamental difference, in the fact that the green product supplied to end-users is the same in the case of electricity, but different in the case of gas. This has implications for the public acceptance, cost and logistics of hydrogen deployment.

The transport by pipeline and domestic utilisation of hydrogen poses significant technical and safety issues. Hydrogen leaks easily, can make metal pipes brittle, and may require different additives and odorants (to make its flame visible and to "smell of gas") than those used with natural gas. Its energy density and flow in pipelines differ from natural gas, with implications for system operations, metering and appliances (and end-user supply pricing – see below). This paper assumes these issues are overcome.

Transition towards a hydrogen-based system

There are possible long-term scenarios (for a low-carbon gas system) in which hydrogen has almost entirely replaced natural gas for supply to end-users; a new hydrogen transmission system may have been installed; and the existing (medium and lower pressure) gas distribution networks have been "repurposed" to convey hydrogen only[3]. To get to such a model, at some future point, government would need to make very significant interventions to enable, direct and coordinate the necessary investments and programmes for switching to hydrogen, including the replacement of existing meters and appliances.

However, it seems unlikely the inception of, and early stages of transition towards, a hydrogen-based system will occur on such a centrally-planned and uniform basis; and it is unclear whether it will involve initially switching significant parts of the existing supply infrastructure to 100% hydrogen. In its November 2018 report the Committee on Climate Change makes a number of findings and recommendations on the steps needed to initiate and drive forward such a transition.

At least one pathway towards a hydrogen system would involve the injection and blending of hydrogen with natural gas in the existing natural gas supply system.

[3] See for example the "High Hydrogen" scenario in the Frontier Economics report.

Current thinking is that hydrogen could be mixed with natural gas in distribution networks, up to a level of 20% (by volume, equivalent to 6% by energy content), without the need for significant changes in distribution pipeline infrastructure[4] or in consumer appliances.

In this paper, we assume a significant early transition period (prior to any comprehensive government-directed programme for conversion) in which there is progressive but geographically diverse growth in the penetration of hydrogen projects, connected to the existing system at distribution level, with a blend of natural gas and hydrogen (up to a maximum safe proportion) being supplied through the distribution system. This implies a complex, heterogeneous, gas supply system as compared with today's relatively simple and linear natural gas system.

As a corollary of such a gradual transition, there would be no sudden step-change in the regulatory and commercial framework for the gas supply system. The main focus of this paper is on this framework and how it would be impacted during an early transition period with (varying) blends of hydrogen in the distribution networks.

Features of such an early transitional phase may include these:

- there will be initial development of experimental/demonstration projects such as H21 Leeds Citygate and Hynet North West, followed (if these are successful) by an ad-hoc roll-out of further projects by various developers;
- the projects may involve (i) new delivery infrastructure (or adapted existing infrastructure), "downstream" of the hydrogen production plant, supplying pure hydrogen to customers; or (ii) the

[4] On the assumption that the replacement of iron mains by polyethylene pipes is completed.

introduction of hydrogen into existing distribution networks, to be blended with natural gas; or (iii) at least in some cases, both;

- early projects are most likely to be for steam-reforming of methane (requiring a supply of natural gas from the existing system). The development and geographic location of steam reforming projects will be highly linked to the potential for offshore CCS and CCUS. Distribution networks in areas which do not have this potential will lag in terms of hydrogen penetration;
- developing local hydrogen demand will be a key investment condition for these projects – and they may contract directly to sell/supply the hydrogen they produce to their directly-connected "hydrogen-only" customers;
- the existing natural gas network operators may be active promoters of (and participants/investors in) the hydrogen projects.

The customer base for gas will become more diverse:

- existing demand will continue, such as commercial and residential space and water heating, power generation and industrial use (including methane feedstock for petrochemicals);
- new demand may include hydrogen (or natural gas) fuelling for transport (road, rail, shipping); other hydrogen-only demand for customers whose installations or processes require it; increased use of gas as a fuel for district heating;
- some gas demand may become more volatile, where customers have greater incentives and flexibility to switch between parallel energy sources (for example, where hybrid heat pump and gas boiler heating is installed);
- part of this demand may be able to adapt to changes (over different timescales) in the blend of hydrogen and methane; other parts may be less adaptable.

Funding the transitional development of hydrogen projects is another challenge. This could involve direct (taxpayer) funding, or other initiatives to allow hydrogen to be competitive with natural gas, for example through carbon pricing, evolution of the RHI (renewable heat incentive), a fixed price CfD against the natural gas market price, or purchase obligations imposed on suppliers or transporters. The price controls of the distribution network operators will also need to accommodate any additional costs they incur. These issues (and their state aid implications) are beyond the scope of this paper.

Basic organisation and regulation of the system

We start by looking at the basic organisation, and principles of regulation, of the gas supply system. In the tables below we first outline features of the current system, and then how these may differ (or need to differ) in an early transition period. Our focus is on the GB system and regulatory regime, but at least some of the issues we identify are likely to arise in any existing downstream gas industry, particularly one in which different parts of the value chain have been "unbundled"/opened up to competition.

Characteristics and organisation – existing system

Our natural gas supply system comprises a single high pressure national transmission system (NTS) operated by a transmission system operator (the TSO, National Grid Gas plc), and 12 lower pressure networks (local distribution zones, LDZs) each operated by a Distribution Network Operator (DNO).

Gas enters the system, mainly at transmission level, from offshore (and some onshore) gas fields, interconnector pipelines to neighbouring countries' gas grids, and LNG (liquefied natural gas) import terminals. It is conveyed down through the system for supply to customers' premises. It may also be stored (injected and later withdrawn) from storage facilities connected to the system, or exported through the same interconnectors (depending on relative demand and market prices either end of the interconnector).

Almost all natural gas supplied in the island of Ireland is imported over interconnector pipelines from the GB transmission system.

The overall system operates on the basis of a broadly common gas specification. Health and safety regulations (the GSMRs[5]) prescribe a specification for gas (by the time it is in a part of the system where it may be supplied to domestic customers) in terms of contaminants, flame and burn characteristics, and qualities which may affect flow in appliances. (This specification includes a maximum limit of 0.1% molar hydrogen.) The TSO applies a broadly common entry specification for gas entering the system at all entry points (allowing it to meet the GSMR requirements).

This means (subject to transportation capacity constraints) that demand at any exit point can be met from gas entering the system at any entry point, which is fundamental to end-user security of supply.

Gas is priced and sold based on its energy content, in other words in energy units (kWh or therms). Quantities of gas (flowing in or out of the system) are calculated by measuring the volume of gas (by metering), and applying a measured calorific value (energy per volume).

Other regulations[6] effectively limit the range of variation of calorific value (CV) of gas supplied to end-users in a given part of the network. They allow a "flow-weighted average CV" (FWACV) to be used for end-user charging, so long as the variation of individual flows lies within a narrow range.

Characteristics and organisation – implications of transition

While the NTS will continue to convey natural gas only, the LDZs will become mixed:

- different parts of the system will convey natural gas only, hydrogen only, or a blend (and obviously this will be reflected in what is supplied to different premises);

5 The Gas Safety Management Regulations 1996.

6 The Gas (Calculation of Thermal Energy) Regulations 1996.

- the composition of the blend will vary by location; it may also vary by time (if, for example, hydrogen production is continuous, and demand swings are met by flexing natural gas flows from the NTS);
- the "average" blend will shift over time towards a higher hydrogen composition (up to the safe overall limit).

The overall proportion of gas entering the system at distribution level (and number of LDZ entry points) will increase.

In terms of the composition/specification of gas:

- the principle of energy-based pricing and selling will presumably apply equally to hydrogen (and any hydrogen/natural gas blend);
- the calorific value (energy per standardised volume) of hydrogen is much lower than natural gas – about one third. That means the volume of hydrogen required to deliver the same amount of energy is three times higher. This has implications for the commercial basis of transportation, although the impact on transportation is partially offset by higher flow velocity (see below);
- as noted above, however, a blend with up to about 20% (volume) of hydrogen has sufficiently similar characteristics to natural gas that wholesale replacement of domestic appliances would not be needed;
- obviously the GSMR "de minimis" limit on hydrogen would need to be revised (when and if the safety concerns are resolved);
- if differing "regional" gas specifications apply, the "whole system" security of supply could be compromised;
- the locationally-diverse (and time-varying) blends of natural gas and hydrogen will present significant challenges for charging on an FWACV basis[7].

[7] The same issue applies in the context of bio-methane, but to date we understand it has not been material in impact.

Basics of regulation – existing system

In common with other utilities, and in line with the economic policy that has prevailed in the UK since the privatisations of the 1980s, the gas regulatory framework protects consumer interests by promoting competition in contestable activities, and through price and other regulation of the ownership and operation of network infrastructure as natural monopolies.

The main regulated activities recognised in the Gas Act 1986 are:

- gas transportation: owning/operating gas pipeline networks – both transmission and distribution;
- gas shipping: the wholesale activity of buying and trading gas and arranging with the network operators to have it transported to customer premises;
- gas supply: the retail activity of selling gas to end-users. A supplier may act as its own shipper, or purchase gas (for on-supply) from another shipper.

Gas shipping and supply are competitive activities, while gas transportation is regulated as a natural monopoly. Characteristics of these markets and the sector regulation include:

- the pipeline network activities are strictly unbundled from the competitive shipping and supply activities (with ownership separation at the level of transmission) – ensuring open, non-discriminatory access for shippers to the system;
- any end-user can choose any supplier to supply its gas (and, in turn, a supplier can choose any shipper) – location does not constrain this, and choice of supplier does not affect the technical characteristics (specification) of gas supplied;
- similarly any supplier (or shipper) can source wholesale gas from any producer or importer – depth and liquidity in the wholesale market ensures competitive pricing;
- there is no price regulation of these competitive "commodity" activities[8];
- facilitating customer switching is seen as key to maximising the benefit of competitive supply;
- there is no "postalisation" of supply charges – or subsidisation across customer groups – broadly the commodity cost of energy is the same in all areas, and network costs of transportation in different LDZs are passed on to customers in full.

In large part these principles are now enshrined in European law[9] on the internal energy market.

The "upstream" commodity activities (production of gas, import of gas or LNG) are similarly competitive activities, not subject to price regulation.

There is a common rulebook for the system (the Uniform Network Code, UNC) which defines the commercial and operational relationships between the transporters (TSO and DNOs) and shippers.

Basis of regulation – implications of transition

In the hybrid world of the early transition towards hydrogen, the foundation principles of national competitive markets seem at risk of being eroded:

- there could be local "markets" with different gas or blends being supplied to end-users in different parts of the system;
- would suppliers/shippers need to procure natural gas and hydrogen in the applicable mix for each "local" market? If so, it is hard to make sense of the

[8] Except of course under the new (and in theory temporary) cap on standard variable tariffs.

[9] See for example: Directive 2009/73/EC of 13 July 2009 concerning common rules for the internal market in gas (the Third Gas Directive).

competitive sourcing in the wholesale market of gas for supply to end-users;

- in any event, it is unlikely that, at least for a long time, hydrogen producers would be in competition with each other to an extent that would constitute a competitive wholesale market;
- end-users will not have a choice in terms of what is supplied to them – that will depend on decisions made by others about hydrogen developments and their integration (or otherwise) into the existing LDZ. Would this also limit end-user choice of supplier?
- these considerations imply the possible need, for some time, for control of the price (at a retail or wholesale "point of sale") of hydrogen production or supply; recognising, however, the potential conflict with the challenge in early phases of incentivising it;
- we have noted that a hydrogen project may sell direct to end-users connected to its pipes, and the DNOs may play a continuing role in the promotion and implementation of hydrogen projects, running counter to the spirit of unbundling;
- the costs of supply to end-users in different parts of the network may differ quite sharply, such that there may be a case for some levelisation in setting supply charges.

A more basic regulatory issue is how the current Gas Act framework applies:

- is it extended to include hydrogen networks (or parts of them, "downstream" of production, which are hydrogen only)?
- absent specific exemptions, or a change in law, the regime would apply, as gas is defined in the Gas Act[10] to include hydrogen;
- for UNC purposes hydrogen-only networks would be unique – the production facilities would represent an inflection point – hydrogen could be conveyed upstream (to the LDZ) or downstream, but natural gas would not flow downwards out of the LDZ. The "whole system" security of supply would not extend to downstream hydrogen-only customers.
- alignment with European law and markets (so far as affecting distribution networks) would be broken (unless these changes are in step with parallel moves in Europe).

[10] S.48 Gas Act 1986.

Commercial arrangements for the gas system

We now look in a little more detail at a few of the main commercial and operational arrangements, enshrined in the UNC, for the system. Underlying these issues are some fundamental questions about whether and how shippers procure and trade hydrogen as part of the gas they deliver into the system, and whether they have any choice about the mix in which hydrogen and natural gas are delivered. In this section we do not try to answer these questions, but look at consequences of possible answers for the commercial arrangements in a first transition phase. We look at transportation, energy balancing, the NTS/LDZ interface and gas supply emergencies.

Gas transportation – existing system

Under the UNC, shippers[11] hold capacity in the NTS, separately at entry and exit points, and in the LDZ, in order to put gas in and take gas out of the system:

- system capacity is defined, allocated and priced on the basis of energy, i.e. in kWh/day. The broadly common gas specification allows this, although the usage and costs of capacity are driven by other technical characteristics;
- this allows the use of a single measure (energy) of gas over the whole commercial framework, including energy balancing (see below);
- the regime is "entry/exit" – in other words, it does not contractually link the points at which gas is put in and taken out of the system – transportation rights are not "point-to-point";
- NTS capacity is allocated (by auction) and traded under market-based arrangements (which rely on substitutability as between geographically proximate points on the NTS);
- shippers hold LDZ capacity at LDZ exit points, on the basis of peak day demand. At "daily read" meter points (see below), shippers apply for LDZ capacity (but booked capacity may be "ratcheted" up by a higher flow on a day). At non-daily read meter points LDZ capacity is allocated automatically, based on demand estimation models and profiles;
- capacity is defined on a per-day basis, without commercial rules for use of capacity within-day (although with some technical restrictions on flow rates);
- shippers pay charges for their booked capacity, and commodity charges (based on flows in energy units) for use of the system;
- at LDZ entry points shippers pay a commodity charge which reflects costs of accepting gas at the entry point, net of NTS and LDZ costs avoided (by entry at the relevant pressure tier of the LDZ), which may therefore be positive or negative. There is no separate capacity charge for LDZ entry.

Gas transportation – implications of transition

We understand the utilisation of capacity, per energy unit, of transporting hydrogen by pipeline[12] is higher than natural gas. Similarly, the variable cost of transporting hydrogen (such as compression and pre-heating) may be different from natural gas:

- will it be possible to use a common energy-based measure of capacity for different blends of hydrogen and natural gas at different points on the distribution system?

[11] DNOs also hold capacity – see below.

[12] This is technically complex, involving parameters including CV, density and velocity of travel.

- the measured energy flows which drive the amount of LDZ capacity held by a shipper (through the ratchet mechanism or the demand estimation models) may not be reflective of actual transportation capacity;
- if capacity definition becomes more fragmented, will it be necessary to move to a shorter (for example, hourly) unit for capacity?
- energy-based commodity charges may not be reflective of the variable costs incurred in transporting different blends of natural gas and hydrogen;
- large increases in the amounts of gas entering the system at distribution level may put pressure on the "embedded" pricing (net commodity charge) of LDZ entry.

On the basis the NTS remains natural gas only, these issues should not directly impact the arrangements for allocating and trading NTS capacity.

Energy balancing – existing system

The system is balanced as a whole, in energy, on the basis of a single "national balancing point" (NBP):

- under the "entry/exit" approach, gas which has entered (and paid to enter) the system at any point (NTS or LDZ) is treated as homogeneous "at" the NBP. It can be taken out of the system at any exit point (subject to paying exit charges);
- alternatively it can be traded among shippers (and others, as traders) "at" the NBP;
- this underpins a liquid traded market, ensuring effective competition at the wholesale level as described above.

Shippers balance their inputs and offtakes of gas in the whole system on a daily basis:

- a shipper's imbalance is the difference between its inputs and offtakes, adjusted for NBP trades, on a daily basis;
- the imbalance is settled by a "cash-out" transaction with the TSO, at prices which incentivise the shipper to avoid imbalance;
- shippers are not exposed to within-day commercial balancing rules.

The TSO manages the overall physical balance of the system:

- the TSO buys and sells (on its own account) quantities of gas (in energy units, as always, and at points on the LDZ as well as the NTS) as needed to achieve a balance, over the system as a whole;
- within-day, the system is operationally balanced (by the TSO and the DNOs) by managing pressures and stored gas (as "line-pack") in the system;
- the TSO can manage locational capacity constraints by selling gas upstream of the constraint and (to maintain an overall balance) buying gas downstream.

Some gas (referred to as shrinkage) within the system is used for fuel (in compressors or pre-heating) or lost or unaccounted for:

- shrinkage is defined on a uniform basis and accounted for by applying percentage factors, separately at NTS and LDZ level, to aggregate gas flows;
- for historic reasons, it is the responsibility of the transporters (TSO, DNOs) to procure shrinkage gas.

At the large majority (by number) of exit points the offtake of gas is not subject to daily read metering[13]:

- demand estimation processes and models are used to estimate daily offtakes (and calculate daily shipper imbalances);
- when a meter reading is obtained (at intervals up to many months), a reconciliation (of the difference between the estimated and metered quantity of gas over the relevant period) is carried out;
- the meter reading is volumetric and the daily flow-weighted average calorific value is used to calculate the reconciliation value.

Energy balancing – implications of transition

As noted above, there are fundamental questions how hydrogen is treated in energy balancing.

In principle, an energy-based NBP can (and should) be maintained, but having significant quantities of hydrogen in the LDZ could raise a range of questions:

- it assumes the acceptability for energy producers of a common price. The economics of hydrogen production may make this an unrealistic assumption. You cannot have a single trading hub for differently priced products;
- this issue is obviously closely tied to the forms of incentive for hydrogen production mentioned above;
- the principle of common, energy-based, entry/exit transportation prices, is fundamental to the NBP (i.e. value homogeneity of gas "within" the system). Offtakes from the LDZ are "imputed" to the NTS without adjustment. If a shipper's ability to exit natural gas "from" the NBP at any LDZ exit point were compromised by different blend specifications within the LDZ, that could undermine the basis of an NBP;
- the same considerations apply to the use of a single imbalance cash-out price.

The potential for differing gas mixes in different parts of the system and at different times may raise other issues:

- will a more fragmented approach reduce the transporters' flexibility to manage the system balance within-day, and require a more granular (for example, hourly) balancing regime?
- will locationally and temporally diverse gas mixes in the system affect shrinkage requirements, and/or shrinkage definition, and so impact the use of uniform (LDZ-wide) shrinkage factors?
- will the TSO's choices of energy balancing or constraint management actions, and the costs of those actions, differ according to the mix of gas in different parts of the system? What new data flows will the TSO need to make these decisions?
- how will these temporal and locational blend issues affect non-daily read demand estimation models and processes, and the calculation (from volume and calorific value) of reconciliation quantities? Could they drive increased volatility in measures (such as "annual quantity") which underpin demand estimation?

NTS/LDZ interface – existing system

At the interface between the NTS and LDZ:

- NTS exit capacity is held by the DNO, not the shippers;
- the DNO also holds "flexibility capacity" which allows the DNO to profile the flow of gas over the day. Flexibility capacity is not separately charged for;
- the DNO manages (and nominates to the TSO for operational purposes) the flow and profile of gas into the LDZ;

13 At some stage, the deployment of smart meters which provide daily reads should remove the need for much of the demand estimation and reconciliation rules.

- the NTS/LDZ interface is invisible in the commercial balancing regime (and the DNO does not participate in that regime).

NTS/LDZ interface – implications of transition

The impact of significant quantities of hydrogen entering the system at LDZ level will need to be considered:

- for system balancing, the TSO may need new LDZ data flows relating to hydrogen production, and hydrogen-only demand;
- if hydrogen production is continuous, then demand swings (within-day and over longer periods) may be focused on a smaller aggregate flow from the NTS, increasing the effective flexibility required (and differentiating LDZs with different levels of hydrogen penetration). This may create pressure to charge separately for NTS exit flexibility capacity;
- a DNO operating an LDZ with significant connected hydrogen production would overall need less NTS exit capacity – which would tend to increase NTS exit charges to other capacity holders (directly connected shippers and other DNOs, and ultimately their end-users) – an early instance of a wider long-term question about allocating costs of the NTS in a world where more bulk supply is at the LDZ level;
- the management of hydrogen (and other) flows on the LDZs could lead to the DNOs assuming more of a "system operator" role, with commercial balancing in the LDZs, in which case the existing balancing regime might "retreat" (from the current whole system perimeter) to the NTS perimeter. That would require new rules for allocating flows at NTS/LDZ offtakes to shippers for energy balancing purposes.

Gas supply emergencies – existing system

Under health and safety regulation (the GSMRs), and related UNC mechanisms:

- a gas supply emergency exists where there is not enough gas to meet demand on the system (with the risk of system pressures becoming dangerously low);
- a single "Network Emergency Controller" (NEC) is appointed for the whole system, with responsibility for the management of an emergency, and ultimately the safe shutdown of the system;
- the operator of each network (and the NEC) must have an approved safety case for dealing with an emergency;
- commercial balancing arrangements are designed to maximise the incentives on shippers to provide gas to the system (or reduce demand) before an emergency is called.

Gas supply emergencies – implications of transition

Alongside the wider health and safety issues of hydrogen supply infrastructure, the gas supply emergency arrangements will need review:

- who will hold the safety case for the hydrogen-only networks? And will (and how will) the NEC have responsibility for them?
- in the case of part of a network which is "hydrogen only", different arrangements may be needed (since gas from the rest of the system cannot maintain pressures) – creating new scope for "local" gas deficit emergencies;
- will the balancing issues discussed above impact the effectiveness of the cash-out incentives on hydrogen supplies in an incipient emergency?

Some thoughts on possible transitional framework

The need to address the issues discussed in this paper is some way off, and will depend on progress in addressing the many technical, safety and economic issues (as well as what transition pathways actually emerge). Developing a revised or new health and safety framework for hydrogen transportation, supply and use will be a more pressing requirement. However, we have given some preliminary consideration to some of the regulatory and commercial issues.

The rudiments of a possible transitional scheme, for distribution-connected hydrogen supply, could look like this:

- there is no attempt to replicate for hydrogen the wholesale procurement of natural gas by shippers. The absence of a competitive market in which hydrogen can be procured, and the need to coordinate procurement to achieve a specific blend of hydrogen and natural gas, make this unrealistic;
- instead, the DNOs are responsible for hydrogen procurement for injection into the distribution networks. In time, this could be on the basis of competitive procurement (against centrally-set targets for the hydrogen mix). At least initially, some regulation of the price at which hydrogen is purchased would be needed; this could be direct, through licensing or other regulation of the production of hydrogen, or indirect, in terms of the price the DNO can pass on;
- the commercial regime for transportation, shipping and supply of gas treats all gas in the system as homogeneous, accounted for (as currently) in energy units. Differing commodity and transportation costs of hydrogen and natural gas are "mutualised";
- the composition of the gas supplied to an end-user (whether hydrogen only, natural gas only, or a blend) does not concern the shipper/supplier. The shipper books and pays for exit capacity, and balances its inputs and outputs, in energy units whilst disregarding the actual composition of gas supplied;
- for energy balancing purposes, the energy in the hydrogen (purchased by the DNO and injected to the system) needs to be credited to the shippers' imbalance accounts. Each DNO would publish, ex-ante (daily and probably more frequently) and perhaps also ex-post, a daily factor representing the proportion of total LDZ (or smaller "exit zone") throughput supplied as hydrogen. Each shipper's offtake nominations and allocations (in the LDZ) would be scaled down by this factor, on a universal basis;
- the DNO would charge the costs of hydrogen procurement as a universal LDZ commodity charge to all shippers, regardless of the location of their individual end-user exit points;
- other differential costs of hydrogen supply (higher transportation costs) would similarly be recovered by the DNO from all shippers on a universal basis, by LDZ, whether by commodity or capacity-based charges;
- if there are material differences in the levels of hydrogen penetration in different distribution networks, some further levelisation (of these incremental energy and transportation charges) could be implemented (through the agency of the TSO or otherwise);
- these incremental charges would not be directly applicable to NTS-connected end-user demand, but again (if this were policy, and unless offset by some form of carbon taxation) this could be addressed through a TSO-implemented charging adjustment.

Such a scheme could address some of the commercial and regulatory issues identified in this paper. It could co-exist with incentive mechanisms for hydrogen development, but it has the potential to overlap with these mechanisms (in terms of the hydrogen price paid by the DNO). A variant (more in line with current policy on incentive mechanisms) would be to have a different, central entity acting as the buyer of hydrogen (and procuring the development of hydrogen projects). Some kind of shipper or supplier levy could recover the purchase costs; but any incremental transportation charges would still flow through the DNO. The same arrangements for energy balancing would apply (and operationally and in terms of data flows, the DNO would be the hydrogen project's counterparty).

Such a scheme could be applied only to the existing distribution networks, or it could be extended into the new hydrogen networks downstream of hydrogen production (i.e. with the overall system extending to include those networks, and shippers and suppliers taking responsibility for exit points to hydrogen-only end-users). The latter would be "purer" but more complex in terms of issues such as security of supply standards (and possibly different pricing of a guaranteed hydrogen-only supply).

Hydrogen supply in the long term

This paper is concerned with early transitional issues rather than long-term outcomes, such as converting the whole system to hydrogen. A limiting factor on transitional arrangements discussed above is the maximum safe proportion of hydrogen blended with natural gas (potentially, 20% by volume) in the distribution networks. For a long-term conversion to hydrogen, the distribution networks (and customer pipework and appliances) will have to be "repurposed" for hydrogen. It is not considered possible to adapt the existing high pressure transmission system to carry hydrogen or a blend with natural gas.

The regulatory and commercial framework for an all-hydrogen system is beyond the scope of this paper (and a long time away). At the highest level, considerations for an "enduring" framework may include:

- there is no reason in principle why there should not be a competitive retail market, analogous to the natural gas supply market (but see below on transition);
- what does the wholesale hydrogen market look like? Is it based on GB production, imports by ship or pipeline, or both? Is hydrogen traded in an international market which sets prices in GB, or will there be a separate GB wholesale market (with a hydrogen NBP)?
- is a national hydrogen transmission system (equivalent to the NTS) established? Or is hydrogen production largely located at the LDZ "gate" (and other demand centres, for example, for transport use);
- is substantial hydrogen production in GB still based on steam reforming (with CCS/CCUS)?
- if so, how is natural gas supplied to these plants – will the national transmission system remain in place, conveying natural gas (presumably largely imported by then) to steam reforming production facilities, or are they sited at the points of natural gas/LNG import?
- is there a continuing separate wholesale natural gas market, or can the two markets be combined? Do the steam reforming plants operate as toll plants or on a merchant basis?
- does the system accommodate continued production (and blending, in the distribution networks) of bio-methane? Do the blend ratios give rise to constraints on the commercial arrangements (similar to those described in this paper)?
- is hydrogen viewed as a "premium" fuel (as natural gas used to be considered) on the basis of a limited scope to produce it, carbon-free, at scale;

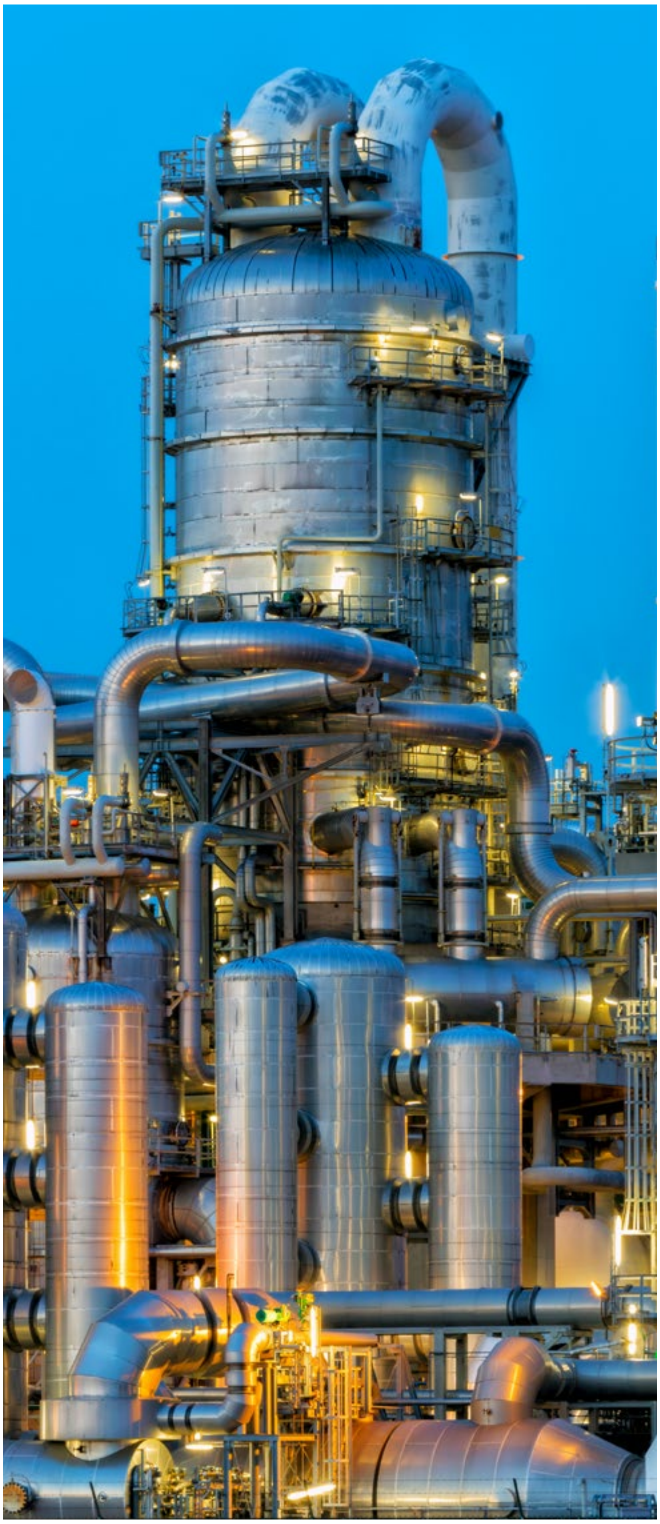
- is the island of Ireland independent in terms of hydrogen production or imports?

Whatever the answers are, getting to that enduring state of affairs will raise another set of transition issues, and (as indicated above) is likely to require very significant government intervention:

- the scale of the transition (to an all-hydrogen system) is no less than the conversion to natural gas in the late 1960s/early 1970s, which was implemented through the state-owned, vertically and horizontally integrated monopoly, British Gas Corporation;
- establishing the necessary incentives, regulatory obligations and compensation mechanisms to implement such a transition, with coordinated and efficient investment, within a competitive wholesale and retail framework, with multiple network operators, will be challenging.

A one-off national step change to all-hydrogen would require the investment in all the end-to-end infrastructure required for hydrogen supply to be completed ahead of the switch, which would be costly. Avoiding that would require either:

- a geographically sequenced roll-out, one repurposed distribution network at a time (and requiring at least the infrastructure and market for bulk supplies to that network to be established); or
- possibly, a series of further incremental steps in the blend of hydrogen in the distribution networks (if a new generation of appliances and meters could accommodate this).



Conclusion

Hydrogen has the potential to play a major role in decarbonising heat in GB, if technical and safety issues can be resolved. Converting to a supply system based entirely on hydrogen is a long way off, and would require significant government intervention. Early moves towards introduction of hydrogen may involve demonstration or smaller-scale projects, developed on an ad-hoc basis. These projects may inject hydrogen into the existing distribution networks, to be blended with natural gas up to a safe limit. The existing regulatory and commercial framework for the gas supply system would need to be adapted to allow for this initial introduction of hydrogen. It would be hard to design a market framework (for this early transition phase) in which hydrogen and natural gas were treated separately in terms of competitive wholesale sourcing, energy balancing and transportation charging. A more "administered" regime, in which shippers/suppliers and end-users are indifferent to the specific blend of hydrogen and natural gas supplied through the distribution networks, may be feasible.

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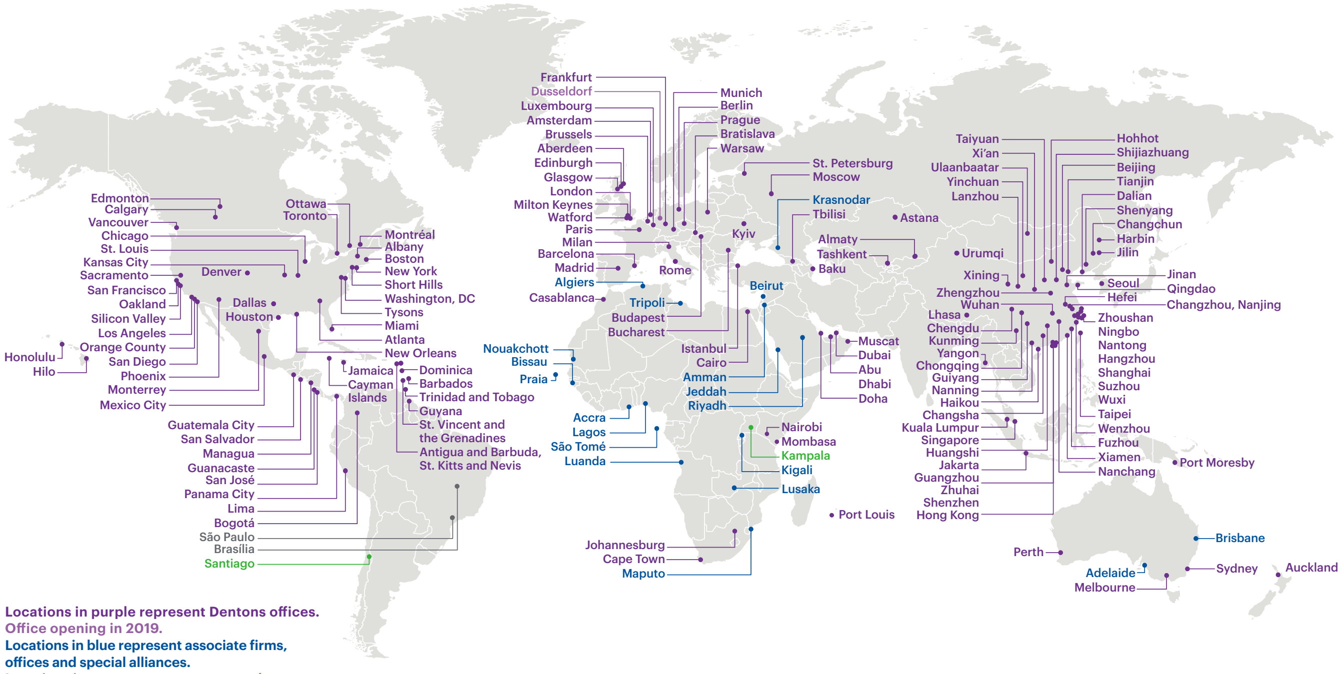

Locations in purple represent Dentons offices.
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Locations in green represent proposed combinations that have not yet been formalized.
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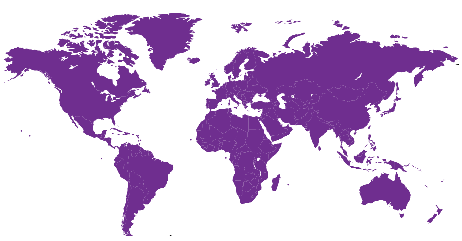
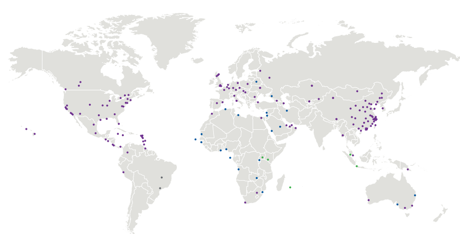
70+
Languages spoken

Total number of lawyers
9,000+

Chambers ranked lawyers
485+



Countries
78



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Locations

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