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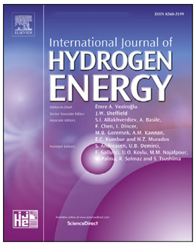

Towards a 100% hydrogen domestic gas network: Regulatory and commercial barriers to the first demonstrator project in the United Kingdom

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HIGHLIGHTS

- This paper explores barriers for the first UK 100% hydrogen distribution project.
- Learnings from pilot projects need to be transferred into UK operational practice.
- Existing regulations present barriers to gas distribution innovation projects.

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ABSTRACT

In the debate on the decarbonisation of heat, renewable electricity tends to play a much more dominant role than green gases, despite the potential advantages of gas in terms of utilising existing transportation networks and end-use appliances. Informed comparisons are hampered by information asymmetry; the renewable electricity has seen a huge grid level deployment whereas low-carbon hydrogen or bio-methane have been limited to some small, stand-alone trials. This paper explores the regulatory and commercial challenges of implementing the first UK neighbourhood level 100% low-carbon hydrogen demonstration project. We draw on existing literature and action research to identify the key practical barriers currently hindering the ability of strategically important actors to accelerate the substitution of natural gas with low carbon hydrogen in local gas networks. This paper adds much needed contextual depth to existing generic and theoretical understandings of low-carbon hydrogen for heat transition feasibility. The learnings from pilot projects, about the exclusion of hydrogen calorific value from the Local Distribution Zone calorific value calculation, Special Purpose Vehicle companies, holding of liability and future costs to consumers, need to be quickly transferred into resilient operational practice, or gas repurposing projects will continue to be less desirable than electrification using existing regulations, and with more rapid delivery.

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Introduction

In the United Kingdom (UK), natural gas plays a prominent role in the energy mix, accounting for 40% of the total energy demand to [1] and 65% of total domestic energy demand [2]. Despite falling domestic production, since 1990 the UK has experienced a 'dash to gas' and the substitution of natural gas is now a huge priority for the UK government's decarbonisation ambitions: in 2018, emissions from gas were 25% greater than in 1990, whereas emissions from all other fuels have been decreasing from 1990 levels [3]. As a consequence, gas contributed to 48% of the UK's 2018 GHG emissions [3]. In order to facilitate the transportation and supply of natural gas, the UK has an extensive gas transmission network consisting of 4760 miles of high pressure pipes [4] and a gas distribution network, made-up of close to 180,000 miles of medium and low-pressure pipes, which delivers gas to most consumers [5]. With gas playing such a major role in the current energy mix, and considering the existence of vast gas network infrastructures, within the context of anthropogenic climate change and decarbonisation targets, various stakeholders are seeking ways of meeting the current gas demand in the face of potentially stranded assets and competencies. Academics increasingly suggest that the integration of hydrogen as a clean energy carrier into regional or national energy mixes represents an opportunity to meet the current gas demand in a manner consistent with the global decarbonisation agenda [6–9]. Indeed, a more holistic integration of hydrogen into national economies is considered in an increasing number of institutional publications [10,11,12] and independent statutory body publications [13]. A shift in political discourse also suggests that deployment of hydrogen and fuel cell technologies, is being considered as potentially having a significant role to play in decarbonisation strategies across power, transport and heat sectors [14–17].

Academics have explored hydrogen energy policy [18], technological roadmaps [19], production [7,20], storage [21,22,23], transmission [24], detectable odorant integration [25,8], and hydrogens role in low-carbon energy transitions more broadly [6,26,27]. Research has also been conducted to explore social and ecological aspects of hydrogen as a clean energy carrier such as public perception [28–31], social practices [32,33] and environmental impact [34]. However, at the time of writing, there is little empirical research which has investigated how insights from the hydrogen energy literature may materialise 'on-the-ground' in demonstration projects, including the potential implications that may be derived from this knowledge when considering future upscaling. According to researchers specialising in transitions studies, the manner in which innovative technologies (or technological configurations) interact on-the-ground with other variables such as user-practices and institutional arrangements is crucial in determining whether or not said technologies move beyond the demonstration phase towards wider deployment [35]. Building upon this insight, this paper will combine i) the desire to add nuance and depth to existing hydrogen energy literature based on what it means for a demonstration project, with ii) a methodological structure and analytical focus which gives primacy to pre-existing understandings of, and empirically observed interactions between, low-carbon hydrogen technologies (including downstream of the meter i.e. domestic appliances), users, and existing institutional arrangements. Focussing on the case study of 100% low-carbon[1] hydrogen for domestic heat in the UK, the aims and structure of this paper are as follows.

The aim of this paper is to develop a better understanding of the key barriers to deploying 100% low-carbon domestic piped hydrogen demonstration projects.

The paper is structured as follows. First is a review of existing international literature concerning low-carbon hydrogen for heat technologies and associated institutional arrangements, user practices, perceptions and preferences. Then the case study section highlights low-carbon hydrogen for heat insights and challenges specific to the UK. The methodology section describes how the empirical data to inform the analysis was gathered (see Fig. 1). The results section then presents the findings from the active research including desk study, regulatory analysis, stakeholder workshops and industry expert engagements. Next, the discussion section explores the extent to which existing literature accurately captures the on-the-ground realities of delivering a 100% low-carbon hydrogen for heat demonstration project, reflecting on both transition synchronicity and the inevitable question of scalability. Finally, the conclusion synthesises and summarises the contribution of this paper to existing knowledge and the direction of future research to support deployment of hydrogen for heat through the gas network.

Hydrogen for domestic and commercial heat

Decarbonisation of heat has historically received significantly less attention than decarbonisation of power and transport, however, more recently, there has been an increased acknowledgement that if countries near polar regions are to meet their climate targets, then low carbon alternatives will need to be employed [36]. Early research suggests that (especially in countries who have historically invested heavily in extensive gas networks and infrastructures) using hydrogen as a clean energy carrier to meet domestic and commercial heat provision may prove to be technologically feasible and economically viable [24,37,9]. It is also popular with existing gas industry incumbents as repurposed gas sector infrastructures and assets (including a significant highly trained labour force) could be utilised [38,39]. Within proposals, hydrogen is sometimes envisioned as a substitute for natural gas, distributed without blending through repurposed distribution networks as 100% hydrogen. Other proposals envision

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[1] When talking specifically about the demonstration project, the term 'low-carbon hydrogen' is used instead of 'green hydrogen' owing to the fact that the demonstration will require an auxiliary public grid connection to ensure security of supply to consumers by supplementing onsite renewable energy production. As the electricity grid is not powered exclusively by renewable energy, the hydrogen produced at the demonstration project will not always constitute 'green hydrogen'.

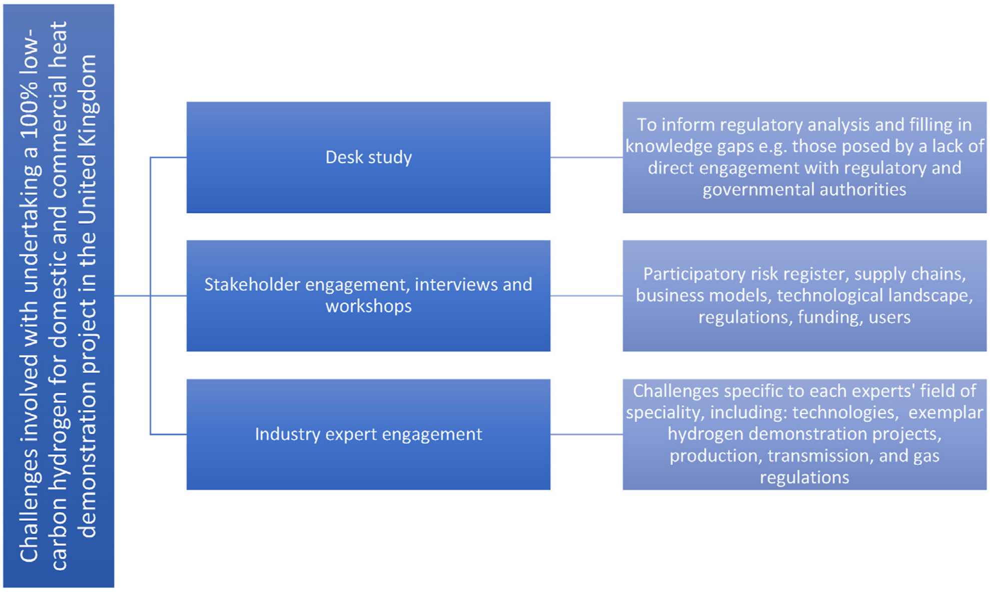

Fig. 1 – Methodology of the study.

blending hydrogen with natural gas up to a maximum ratio of 20% hydrogen.[2] However the amount of allowable hydrogen in gas networks varies from country to country, with the UK having one of the lowest limits [9]. This is a good example to illustrate the international disparity in the required regulatory adjustments. With regards to the production of low-carbon hydrogen, Steam Methane Reforming (SMR) with Carbon Capture and Storage (CCS) and water electrolysis powered by electricity generated through renewable energy technologies represent two of the most prominent low-carbon production methods currently under consideration [9]. The latter production method, also known as 'green' hydrogen production, distributed through new and repurposed gas networks without blending with natural gas (i.e. 100% hydrogen), along with associated domestic equipments such as boilers, meters, and appliances, constitutes the hydrogen for heat configuration engaged with throughout this paper.

Hydrogen for heat and users

Research suggests that many low-carbon heat technologies, such as heat pumps, district heating, solar heating and biomass, could be significantly disruptive to install and/or may require behaviour change from end-users, both of which are deemed as undesirable and potential barriers to uptake [36,38,9,41,42]. Some academics suggest that, on the other hand, hydrogen may offer more flexible and less disruptive heat than contending low-carbon heat technologies, whilst also circumventing the need for end-user behaviour change [36,38,9,41,42]. However, whilst there is precedent for relatively undisruptive domestic gas conversion programmes (e.g. UK transition from 'Town Gas' to natural gas [9]) conversion at a similar scale today could be significantly more challenging due to the interconnected nature of the current gas network [38]. Concerning domestic end-user behaviour change, some academics have highlighted that there would be virtually no difference between a natural gas and a hydrogen boiler due to their operational similarities [38]. However, social science researchers have noted that there are 'specific chemical differences between hydrogen and natural gas' which may require changes to the incumbent social practices of end-users, especially when considering disruption to hob-practices induced by the near invisibility of a hydrogen flame in a domestic scenario [32]:8; notably, research conducted by [33]:3870 found that 'participants imagined their practices of cooking would be severely disrupted while their practices of heating would be largely unaffected'. It should be noted that the risk of increased injuries associated with hydrogen flame visibility compared to methane are adequately controlled when considering ignited gas releases [43]. Caulfield's work however does not address the perception issues raised by [33]:3870.

Another important factor closely related to users concerns perceptions of safety; although there is a lack of research concerning perceptions of safety specifically related to hydrogen for domestic heat, there are a number of insights concerning safety perceptions of hydrogen technologies more broadly which are worth considering. Despite occasional associations of hydrogen with the Hindenburg zeppelin disaster and the hydrogen bomb, a consistent finding regarding hydrogen perception research centres around a lack of meaningful knowledge on behalf of the general public [28,30,32,44]. However, academics have also drawn attention to the possibility that an 'early large accident' could change public perceptions on the matter, whilst 'effective public education will be necessary to achieve the widespread social acceptance of hydrogen technologies' [45]:21.

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[2] Studies suggest that existing transmission infrastructure, which is made of iron, is not suitable for transporting 100% hydrogen, rather proposals envision a ratio of between 2% and 20% hydrogen mixed with natural gas; research also suggests that a maximum of 20% hydrogen can be blended with natural gas if existing transmission networks and consumer domestic appliances are to function without replacement [40].

Green hydrogen for heat; the technological landscape

Both academics and industry organisations have suggested that conversion to hydrogen could be technically feasible and economically viable [24,37,9]. However, in the UK for example, research suggests that such a conversion could take between 10 and 20 years and, in addition to laying new transmission network pipes,[3] would require old natural gas boilers and appliances to be switched out for hydrogen ready appliances (or for existing boilers to be retrofitted to enable the use of hydrogen) [37]. At present, there are no certified hydrogen ready boilers or appliances [46,47]. In addition to there being a lack of certified hydrogen ready boilers and appliances, lack of domestic hydrogen meters is also recognised in the literature [38,46]. However, [9], p. 480 identify certain steps that could be taken to ease this conversion, thereby reducing costs and time, such as 'legislating for standardised back-plates for all new boilers'.

Green hydrogen is produced with the aid of electrolysers, using water and renewable electricity as inputs. *Alkaline* electrolysers and Proton Exchange Membrane, or *PEM*, electrolysers arguably constitute the two front-runner electrolyser technologies when it comes to green hydrogen production. Alkaline electrolysers are a more commercially established technology than PEM, with higher reliability, safety, and durability, with a long lifetime of up to 15 years [48,9]. However, alkaline electrolysers suffer from slow start-times, whereas PEM electrolysers have an rapid power cycling capacity which makes them much more suited to utilise a more fluctuating supply of electricity e.g. from wind and solar farms [36,9]. PEM electrolysers, despite being first introduced in the 1960's, only reached commercialisation in the last decade [9], whilst some suggest they are still in a stage of low maturity and demonstration [49]. PEM electrolysers currently cost approximately twice as much as their alkaline counterparts [9] – p476.

Suitability of existing institutional arrangements in facilitating green hydrogen for domestic and commercial heat

One of the most important components to consider when exploring the suitability of institutional arrangements in facilitating disruptive technologies moving from demonstration to large-scale roll-out is difficulties regarding regulations. With regards to hydrogen configurations as disruptive technologies, [49]:292, state that 'current regulation across the power, gas and heat industry would need to be adapted for an effective penetration of hydrogen energy systems'. According to [47]:296, regulatory issues include, 'the need to demonstrate hydrogen safety standards, the need to develop transparent and equitable funding models, and the need to develop gas standards that ensure lowest possible GHG emissions associated with hydrogen'. Furthermore, [42]:23, states that 'the gas chain is complex … for hydrogen to develop, each link [in the value chain] would have to see a benefit … [however] consumers and other players may see no advantage for themselves in a switch to hydrogen and require incentives or regulation to persuade them to change'. However, [46]:5 suggests that in the UK 'pipeline safety regulations already encompass hydrogen use and provide guidance on pipeline design'.

Another vital aspect of institutional arrangements concerns funding for capital (CAPEX) and operational (OPEX) expenditure. This is particularly important for new technologies which often need protection from market conditions while learnings, networks, and business models can be developed [35]. Hydrogen production by electrolysis is currently capital intensive [46,49]. After the system has been purchased and installed, ongoing operational costs need to be met including water, electricity, maintenance, and labour [49]. The OPEX of hydrogen production via electrolysis is highly dependent on the price of electricity, which can fluctuate significantly [50]; this is potentially problematic when we consider that, in a domestic heat scenario, green hydrogen is competing against a cheap incumbent in natural gas. With this in mind, it is worth noting that there may be opportunities to generate additional revenue and thus make hydrogen for domestic heat more economically viable (in both the short and long-term)[4]; for example, a much cited benefit of an increased role for hydrogen in future energy systems is that associated technologies can be leveraged to circumvent the curtailment of intermittent renewable energy technologies and more generally act to balance electricity grids [6,7,51,52]. Power-to-gas (P2G) is increasingly cited as an means to meet this challenge [53,48], whilst commercial opportunities (e.g. electricity balancing services) are now recognised and promoted in many countries [54,55]. However, there is little pre-existing literature which details the extent to which ambitions to generate additional revenue (e.g. provide grid balancing services) are compatible with servicing domestic heat consumers within the paradigm of existing institutional arrangements.

Case study: the United Kingdom hydrogen landscape

According to Ref. [56]:623 'the UK's very low penetration of renewable technologies for heating is in part a direct consequence of historically ample [although now mainly imported at 54% [1]] supplies of natural gas, availability of extensive gas transmission/distribution networks and the comparatively low upfront costs and efficiency of gas boilers'. To date, research on the deployment of hydrogen in the UK has centred around the transport sector where technologies and/or infrastructures involving cars, buses, ferries and planes are all being trialled [57–61]. But interest in hydrogen for heat is now increasing [62]. Projects in the pipeline cover a variety of hydrogen for heat configurations, including live demonstration of 20% blended green hydrogen injected into a private gas distribution network [63], feasibility study of 100% green

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[3] Hydrogen can be transported throughout the existing plastic polyethylene sections of the gas distribution networks, although the gas transmission network would have to be replaced as the iron pipes currently in use are not suitable for transporting hydrogen [24].

[4] On the other hand, an increase in either CO2 or natural gas prices would also serve to make hydrogen production via electrolysis more economically viable vis-à-vis (currently cheaper) production methods which rely on the use of hydrocarbons.

hydrogen injected into a public distribution network [64], as well as hydrogen produced by SMR with CCS utilisation blended at a 2% ratio with natural gas and injected into the national transmission system [65,66].

Concerning the hydrogen for heat technological landscape in the UK, a consortium of technical experts and specialists, led and managed by engineering consultancy firm ARUP, on behalf of Department of Business, Energy and Industrial Strategy (BEIS), are currently in the process of undertaking a 3-year project, named Hy4Heat, which aims to develop a number of required technologies including domestic, commercial and industrial appliances [67,68]. It is also worth highlighting the 'Future Billing Methodology' project, a 'proof of concept' exercise led by Ref. [69] which seeks to explore potential billing regimes in a future where a wider range of low-carbon and alternative gases are present in the gas grid. With regards to heat decarbonisation innovation, research suggests that there has been relatively limited investment by incumbent actors within the UK heat sector [39], despite the fact that much of the research around heat decarbonisation, especially hydrogen for heat, is associated with gas network incumbents [37,70–72]. Various suggestions have been made with regards to why there has been an apparent lack of investment by incumbent actors, ranging from 'absence of mechanisms to mitigate and share the long-term risks of the initial investments' [45]: 20 to 'policy and regulatory support for low carbon heat which is not ambitious enough and as a result, the lack of a clear market for low carbon heat' [39]:5.

Methodology

The data to inform this paper was gathered through two rounds of research on the regulatory and commercial challenges involved with undertaking a 100% low-carbon hydrogen domestic gas network demonstration project in the UK.[5]

The first round of research took place between July and September 2019 at an early stage of a wider industry project when the location of the demonstration site had yet to be confirmed. Due to the lack of site specificity, we took a high-level approach which utilised desk-study, stakeholder interviews and workshops, and industry expert engagement to explore the pros and cons of various regulatory and commercial approaches which could potentially be utilised to deliver the demonstration. The second round of research took place throughout March 2021 at a later stage of the wider industry project when the location of the demonstration had been confirmed; this round was concerned with reviewing the fine details of the proposed regulatory and commercial approach(es) and consisted of stakeholder engagement and desk-study. This round served to 'close the loop' and provide feedback on the optioneered models specific to the confirmed demonstration site.

Stakeholder interviews and workshops took place over a 3-month period from July until September 2019, followed by further stakeholder engagement throughout the month of March 2021. All interviews and workshops were audio recorded and transcribed. Stakeholder interviews covered a variety of topics including supply chains, business models, technological landscape, regulations, funding (CAPEX and OPEX) and user-practices – all in relation to undertaking a (100%) low-carbon hydrogen for domestic and commercial heat demonstration project in the UK. Workshop activities consisted of an iterative participatory risk register analysis (revised and updated three times over the course of the project), with 8 participants consisting of representatives from a gas distribution network operator and gas and energy consultancy firms. The industry representatives were chosen for their specialist knowledge and were thus well informed, active, and vocal throughout the process. Finally, in both the first and second rounds of our engagement, desk study was undertaken to inform regulatory analysis. The desk study also served to complement the primary data gathered through stakeholder and industry expert engagement by filling in any gaps in knowledge that existed.

It is important to note that all actors engaged with throughout the stakeholder and industry expert engagement processes have a vested interest in seeing hydrogen as clean energy carrier penetrate the UK (and international) energy landscape. The industry representatives had requested that we did not include the national regulator in our engagement, so they could speak to us freely without concerns for their own relationship and strategic communications with the regulator. All engagement with stakeholders was conducted under the Chatham House Rule; i.e. no statements should be attributed or attributable to particular individuals. Interviewees were anonymised in accordance to standard research ethics.

Results

The results from our active research reveal two potential models which could be utilised to deliver a 100% low-carbon hydrogen for domestic heat demonstration project in the UK.[6] Each of the models have their own advantages and disadvantages (both regulatory and commercial) and reveal numerous practical insights which add nuance to pre-existing understandings observable in academic literature (see appendix 3 for more details).

Model A (Fig. 2) was formulated during the first round of active research when the demonstration proposal lacked site specificity. Analysis suggested that the project lead may run into regulatory difficulties concerning their gas transporter license, specifically: restrictions regarding operation of the

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[5] The research undertaken by the authors of this paper constitutes one of over a dozen targeted pieces of work which make up the evidence and safety case of the proposed low-carbon hydrogen domestic gas network demonstration project. The term 'research project' is used to refer specifically to the regulatory and commercial work undertaken by the authors of this paper, whilst the term 'wider project' is used to refer to the demonstration and all its constituent parts as a whole.

[6] In total, 6 model were optioneered over the course of the project. However, for the purposes of this paper, only the two most viable approaches (one from the first round of active research and another from the second round) are engaged with here).

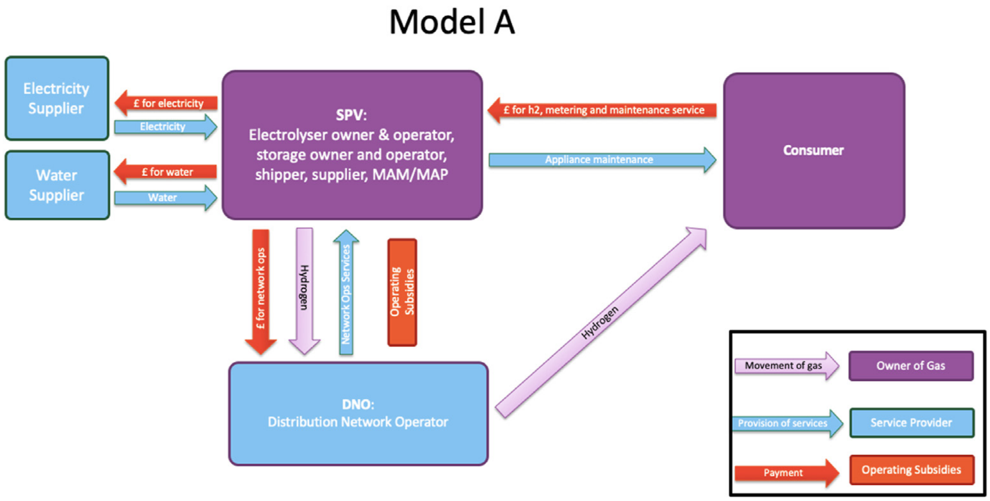

Fig. 2 – **Flow diagram illustrating the direction of energy flow, the parties involved and their roles for Model A.**

electrolyser; concerns regarding adherence to non-monopolistic business models; and, the promotion of competition overseen by the national regulatory body aimed at ensuring the end consumer is protected (see appendix 1 for more details). Model A was formulated to mitigate these challenges (in the short term) by utilising a Special Purpose Vehicle (SPV) to undertake the roles of electrolyser operator, storage operator, shipper, supplier, and Meter Asset Manager (MAM). A commodity balancing mechanism was also assumed to ensure that consumers would be charged no more than natural gas equivalent prices for their consumption of hydrogen. Nevertheless, regulatory analysis revealed that (despite attempts to mitigate) Model A would still require exemptions or derogations to be granted by the national regulator. These derogations would be designed to support the project by enabling a project specific SPV to undertake licensable activities on a small (300 customer) scale to enable learning to be developed. This model presents benefits in that it allows for greater operational control of the supply chain by a single actor (the project lead) thus reducing the commercial complexity of the model and reducing the need for more complex price support arrangements; in other words, it was reasoned that, in this case, simplicity would contribute to security of supply.

The second model (Model B, Fig. 3) was formulated during the second round of active research when the wider project was more developed, including confirmation of a specific site for the demonstration. Model B sees the creation of a SPV as electrolyser operator and storage operator but (unlike Model A) utilises an independent shipper and supplier. Regulatory analysis found that, the only necessity would be a letter of comfort by the national regulator regarding the exclusion of

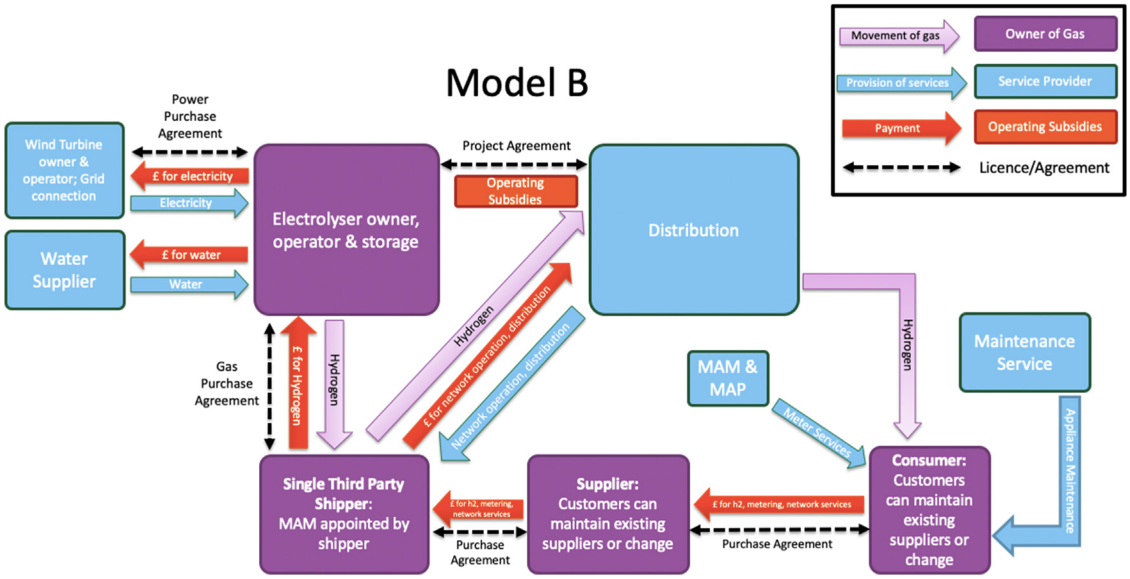

Fig. 3 – **Flow diagram illustrating the direction of energy flow, the parties involved and their roles and the associated agreements for Model B.**

the hydrogen stream from the Local Distribution Zone Flow Weighted Average Calorific Value calculation (although it was also noted that possible amendments to the Uniform Network Code (UNC) may surface as the project develops). It is also worth noting that under Model B, the national regulatory body strategy of promoting competition and avoiding monopoly services is realised to a much greater extent than Model A as it reflects current conventional models in place for natural gas, with actors carrying out the roles that they are accustomed to; this is a strong contributing factor which it was reasoned makes Model B the most viable and least disruptive of all approaches considered throughout the research project (see appendix 3 for more details).

In addition to regulatory considerations associated with the aforementioned approaches to deliver the demonstration, our results also reveal further practical insights related to equipment, end-users, funding and revenue generation:

Regarding equipment, industry experts indicated that using more recent PEM electrolyser technology might offer more operational flexibility than alkaline counterparts and reduce the cost of purchasing electricity from the grid, whilst maximising the use of the renewable energy sources. This flexibility however is likely to come at the cost of a lower reliability thereby suggesting that the role of operating the electrolyser is high risk; this suggestion was also highlighted by multiple experts who were engaged with. This makes it more difficult to attract a potential operating entity. It was also found that the project lead cannot operate the electrolyser due to license restrictions; in order to fulfil this value chain role a license derogation or, alternatively, a license modification would need to be sought in order to allow the project lead to operate the electrolyser. Taking this into consideration, it was suggested by experts and stakeholders alike that there needs to be an incentive to attract an entity to the role, one suggestion being that the funders could potentially underwrite the entity undertaking this role. Another option raised concerned the potential creation of a Special Purpose Vehicle (SPV) (a subsidiary created by a parent company to isolate financial risk) to undertake high-risk value chain roles; this approach was ultimately utilised in both of the aforementioned models ('Model A' and 'Model B).

Concerning hydrogen gas meters, experts and stakeholders engaged with during the first round of active research agreed that fiscally approved meters need to be used for the demonstration project; it was confirmed in the second round of active research that these will be sourced from an ongoing hydrogen appliance innovation project (the Hy4Heat project). Furthermore, it was acknowledged in the first round of active research that more clarity is needed with regards to the expected cost of purchase, installation and maintenance of hydrogen boilers, appliances and meters – it was suggested that this may require a new entity to be added to the commercial model, or funding directly from the distribution network operator/project lead. During the second round, it was confirmed that the purchase and installation costs associated with domestic hydrogen appliances will be met by the demonstration project lead (including the costs of maintenance until the end of the project's initial phase).

Regarding end-user experience, experts suggested that deployment of hydrogen for heat is potentially less disruptive than alternative low-carbon heat decarbonisation technologies. It was noted in the first round of active research that, depending upon the chosen site for the demonstration project, a significant amount of disruption could still be expected (particularly if converting homes which currently meet heat demand via electrified sources). However, it was confirmed in the second round that the site chosen for the demonstration project consists of homes which meet their current heat needs through natural gas and should thus be less disruptive to make hydrogen ready. Nevertheless, hydrogen ready appliances and boilers will be provided to consumers who sign up to participate in order to incentivise them to take part in the local trial – it was acknowledged that the test will be if people continue to sign up to the trial after the incentives cease to be offered.

Finally, with regards to funding and revenue generation, experts engaged with during the first round of active research agreed that both CAPEX (capital) funding and OPEX (operational) subsidy from either government and/or regulator are essential to ensure the project can be delivered. Findings from the second round reveal that funding has been sourced for the project from the regulator, national government and project partners which will meet CAPEX as well as OPEX needs (including, most notably, ongoing funding for the commodity balancing mechanism) for the duration of the demonstration. However, findings from the second round suggest that meeting the commodity balancing costs could be problematic when considering both an enduring regime beyond demonstration project completion and future upscaling. Meanwhile, it was found that significant revenue opportunities are unlikely to be generated through participating in balancing services owing to the prerequisite demand of ensuring security of supply for the duration of the demonstration. See appendix 3 for an overview of the results categorised as relating to: end-users, equipment, funding and revenue generation, and regulations.

Discussion

The discussion section explores the extent to which existing literature accurately captures the on-the-ground realities of delivering a 100% low-carbon hydrogen for heat demonstration project, reflecting on both transition synchronicity[7] and the inevitable question of scalability. Framed around four thematic contributions, analytical focus gives primacy to pre-existing understandings of, and empirically observed interactions between, low-carbon hydrogen technologies/equipment, end-users, and existing institutional arrangements (including funding and revenue generation, and regulations).

Equipment: electrolyser technology, boilers, household appliances and meters

The academic view that PEM electrolysers are the most appropriate technology for producing hydrogen from

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[7] Here synchronicity refers to the extent to which moving parts of the hydrogen for heat transition, for example the development of hydrogen ready equipment, regulations and safety standards, are available and appropriate for utilisation in practical demonstration projects and future upscaling.

renewables electricity [36,9] was shared by the industry experts engaged with, but they also provided additional insights. One hydrogen expert with first-hand experience of using PEM electrolysers for innovation projects felt that the technology is not currently operating at the Technology Readiness Level that (the few current) manufactures would have people believe. He suggested that reliability was still an issue with the handful of current projects where more 'advanced' PEM electrolyser technology is being used. This raises both financial risks and public image risks when considering hydrogen for domestic heat as there is a legal requirement to ensure security of supply to domestic consumers. Discussions on contingency arrangements if the electrolyser would fail led experts to propose a contract with an industrial hydrogen provider to deliver hydrogen to site via tube trailers. This illustrates the dependency of a demonstration project on other successful actors in growing (regional or national) hydrogen supply chains, an insight which is likely to hold its relevance when considering future upscaling. Other expensive redundancy measures also have to be factored in, such as using two electrolysers (each of which would be sufficient on its own) and local hydrogen storage (contingency in case of supply interruptions). These challenges have the potential to slow the transition down and increase its cost.

Whilst several manufacturers are developing domestic hydrogen technologies, at the moment there are no hydrogen (only) boilers, household appliances and meters that are certified for domestic use in the UK [46,47,9]. The aforementioned Hy4Heat programme, which is developing these equipments, is due to complete in March 2021, so from a technical perspective these barriers should be addressed soon. Concerning non-technical barriers, uncertainty created by lack of visibility with regards to the expected cost of purchase, installation and maintenance of domestic hydrogen equipments was mitigated for the duration of the demonstration by ensuring additional funding will be made available directly from the project lead. However, it remains to be seen whether these costs will be similar to, or more expensive than, incumbent natural gas equivalents; this will likely influence consumer willingness to transition to hydrogen for domestic heat beyond (geographically and temporally) the demonstration project. There is also the issue of (immature) supply chains, including both manufacturing jobs and long-term maintenance. This highlights the prerequisite role of synchronicity if future transition is to occur; in order for hydrogen for heat to be upscaled in the UK, certified training programmes would need to be made readily available for the 130,000 registered gas engineers and 74,000 business who operate in the heat sector [39], in addition to catering for newly trained engineers who may be required if a significant roll-out and conversion were to ensue. If future subsidies for low-carbon transitions were predicated upon the requirement that domestic supply chains are created in the process, this would be highly beneficial when considering both transition synchronicity and future scalability of hydrogen for heat in the UK.

End-users: disruption, incentivisation, safety and behaviour change

Does hydrogen for heat represent a less disruptive pathway to decarbonisation of heat than competing technologies (notably heat pumps)? Whilst not all identified literature agrees with this analysis (e.g. Refs. [39,73], it is a narrative expressed by many authors [9,36,38,41,42]. This rhetoric was also evident during industry expert engagement where it was expressed by an employee from a national gas transmission operator in the UK who spoke of 'intangible costs' of disruption reduction which make hydrogen attractive. However, findings from stakeholder interviews and workshops add nuance to this assertion by highlighting that not all existing housing stock easily lends itself to hydrogen for heat. For example, at one of the sites which was shortlisted for hosting the demonstration (but ultimately not chosen), homes are heated with electricity, mainly through storage heaters. Currently, electric heating is far more expensive than gas heating in the UK so these are consumers who would stand to benefit from this fuel switch (assuming hydrogen is sold at natural gas equivalent prices). But conversion of electrically heated homes to hydrogen gas heating is highly disruptive; in addition to new boilers, appliances and meters, pipework would also have to be fitted throughout homes. Furthermore, under this scenario an entire distribution network would have to be laid which would entail significant local disruption to roads. Whilst this issue is not applicable to the demonstration project in question, it does highlight areas of concern when thinking about scalability; it may be the case that certain housing stock (notably those not connected to the natural gas grid) would be better served by low-carbon electrification combined with energy efficiency measures, as opposed to conversion to a hydrogen network.[8]

Conversion to hydrogen (even in homes already connected to the natural gas grid) will inevitably still entail some level of disruption; findings from stakeholder interviews suggest that incentivisation, for example offering free boilers and appliances, is considered a potential option to mitigate against consumer concerns; this interpretation converges with pre-existing literature which suggests incentivisation (or regulation) may be required to persuade consumers to transition [42]. However, stakeholders noted that in order for this incentive to be more than a mere offsetting measure, hydrogen would have to be sold at natural gas equivalent prices. Stakeholders were confident that the highlighted incentives would be sufficient in enticing consumers to sign up to the trial, however, without an actual trial it is difficult to say if such optimism is warranted; there are many examples of technical experts miss-judging the public responses with regards to supposedly beneficial interventions in their homes or neighbourhoods (e.g. protests against domestic smart-meters [74]; protests against mobile phone masts [75]). Anticipated consumer willingness to accept hydrogen for domestic heating also hinges on public perceptions of safety. Much existing research considers hydrogen vehicles and fuel stations (e.g. Refs. [76,29,30] but based on those it would be reasonable to anticipate that people will have limited knowledge of hydrogen (indeed, unfamiliarity with energy technologies is a consistent finding in related literature; [77]). However, stakeholders were optimistic about public acceptance, since gas mains and domestic gas burning appliances

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[8] It should be noted that with 85% of domestic heat provision in the UK currently being met by natural gas [1].

are already the mainstream heating configuration in the UK. Building a hydrogen demonstration cabin on-site to showcase the technology to the public, they argued would give potential consumers the opportunity to feel the heat and cook on the hobs and this would quell any uncertainty regarding usage and safety. We add that a demonstration cabin would also be important for facilitating customer experimentation with cooking facilities which may require changes in incumbent end-user social practices.

It is clear that considerations surrounding consumer uptake speaks to concerns regarding scalability; will the incentivisations detailed above be available for future transitions? Will hydrogen continue to be sold to consumers at natural gas equivalent prices? Will educational tactics such as an on-site hydrogen demonstration cabin will be enough to quell safety fears and encourage transition to a new technology? The answers to these questions are as yet unknown but will likely have major consequences when it comes to consumer willingness to transition beyond the demonstration project. If public confidence fails, then the transition fails which naturally leads one to ask whether industry is being over-confident and if more effort to engage the public is in fact required. However, given the high levels of public support for a low carbon transition *in principle* in the United Kingdom, it may be that most residents will accept a change that is better for society, even if it has little or no direct benefit to them. Public trust will remain the key factor.

Funding and revenue generation: CAPEX, OPEX and balancing services

Hydrogen production through electrolysis is capital intensive [46]. It therefore comes as no surprise that industry experts and stakeholders agreed that CAPEX funding from governmental departments and/or national regulatory bodies is essential to ensure the demonstration can be delivered. As was noted in the results section, the project lead has secured CAPEX funding from both the United Kingdom regulatory body and the national government. This funding was complemented with smaller contributions from the project lead and wider gas sector partners. However, whilst securing capital funding is essential for ensuring the successful delivery of demonstration projects, concerns were raised by stakeholders and experts regarding the lack of profit likely to be generated; in practice, this can make it more difficult to attract certain value chain entities (for example an entity operating a PEM electrolyser will have to accept a lack of profit potential in addition to high risk). This means that for hydrogen demonstrations, project leads may be forced to step-up and operate undesirable value chain role (perhaps using a subsidiary or Special Purpose Vehicle as mooted for the production of low-carbon hydrogen for the 100% hydrogen demonstration). In the scenario described above, as well as missing out on an opportunity to grow a supply chain consisting of diverse actors, (or worse, risking inadvertently promoting knowledge, expertise and experience sequestration in the hands of a small number of incumbent organisations), we are left in a situation where an actor attempting to demonstrate low-carbon innovation is in the precarious position of financial culpability. Our findings could be interpreted to converge with those of Ochoa Robles, De-León Almaraz & Azzaro-Pantel [78]:20 who state that lack of investment by incumbent actors is due in part to an ‘absence of mechanisms to mitigate and share the long-term risks of the initial investments’. On the other hand, they could be interpreted as highlighting the political question as to whether incumbent actors should be expected to take on more financial risk when attempting to innovate?

As has been noted, hydrogen for heat related OPEX will include costs such as water and electricity for hydrogen generation, maintenance and labour [49], with the price of electricity constituting the most financially fluctuating input. With regards to fluctuating electricity costs, what this means in practice is that alkaline electrolyser operators, whose technology tends to require a constant supply of electricity to perform optimally in a reliable manner, should seek a contractual arrangement with electricity supplier(s) that reflects the operational need. This could perhaps be satisfied by negotiating a Power Purchase Agreement (PPA) with a green energy supplier. Alternatively, utilising more recent PEM technology might offer more operational flexibility and reduce the cost of purchasing electricity from the grid, whilst maximising the use of the renewable energy sources and learning opportunities (however, as stressed, uncertainty regarding the reliability of PEM electrolysers is an issue associated with high financial risks and public image risks). It is worth noting here that in an upscaled hydrogen for heat scenario, actors involved in supply and storage may be able to leverage associated technologies to generate additional revenue through participation in balancing services - this would serve to make the endeavour more economically viable. Furthermore, in the short to medium term, further investigation will be required concerning any commodity balancing mechanism; this will be necessary to ensure a fair hydrogen price for consumers (natural gas equivalent). Whilst this cost has been met for the demonstration, the challenge is less easily surmountable when considering upscaling. Without funding mechanisms which ensure that hydrogen can be supplied at a competitive price until technological maturation and scale-up enables market competiveness, it is unlikely that consumers will voluntarily transition to hydrogen for heat. If a mechanism is not found to ensure competitive cost, then research will be required to understand potential impacts that transition to hydrogen for heat could have on consumer affordability, including fuel poverty levels. These issues speaks back to earlier discussion regarding how best to (and who should) fund low-carbon transitions (including the development of transparent and equitable funding models) decisions which as noted, are political ones.

Regulations

Regulatory frameworks are often considered one of the main institutional hurdles inhibiting the upscaling of various hydrogen configurations [45,49]. However, as our results demonstrate, under both ‘Model A’ and ‘Model B’ there is alignment between many (but not all) existing natural gas regulations and standards in a neighbourhood level hydrogen for domestic heat scenario (see appendices for more details). As noted, perhaps the most significant regulatory concern centres around the ability of highly regulated entities to operate certain value chain roles (most notably hydrogen production). Our findings suggest that it is gas distribution network operators whom are most affected by this institutional arrangement; these findings align with those of [39] who suggest that gas networks are the incumbents most at risk from heat decarbonisation due, in part, to the strict regulations that control their behaviour. Furthermore, our findings highlight concerns regarding restrictions to business models that are monopolistic. Although monopolistic business models may be suitable for demonstration projects in order to enable innovation whilst also ensuring security of supply (e.g. Model A), approaches which are closer to preexisting natural gas arrangements are likely to be preferential in the medium to long-term (e.g. Model B). Whilst it was found that these points of contention can be mitigated for the duration of any demonstration project (by the formation of a SPV and the easing of monopolistic policing respectively), these restrictions nevertheless raise significant questions when considering future upscaling of hydrogen for heat, namely: will highly regulated gas sector companies continue to be restricted from diversification involving, for example, distributors also being licenced to produce gas? And how best to integrate hydrogen into a liberal regulatory environment?

Conclusions

Many countries are providing some support for the development of a green hydrogen economy [79]. Whilst important technical challenges remain, it is also recognised that existing regulations need to be adapted, financial support provided and ‘legal pathways’ found [80] in order for the hydrogen sector to grow and mature. Internationally, early deployment has focused especially on hydrogen refuelling stations, but other sectoral green hydrogen pilot or demonstration projects have taken place, e.g. for the production of green cement and green steel [81,82]. This paper has explored the challenges of starting a 100% low-carbon hydrogen gas network demonstration project at the neighbourhood level in the United Kingdom. This is a world-first. The paper identifies the barriers hindering the ability of otherwise strategically placed actors from driving innovative change and provides suggestions regarding the regulation and adaptation required to ease transition to hydrogen for heat in the United Kingdom.

Businesses engaged with fossil fuel distribution are especially at risk from a shift to decarbonised fuels. At the moment, consumers perspectives are largely untested and future costs to consumers remain unknown, including costs of the fuel, appliances and maintenance. With strong and continuous policy support, technological maturation and scaled-up production can be expected to improve the market competiveness of green hydrogen over time, but in the meantime, this also implies the need for continuous financial support (tax on natural gas and/or subsidies for green hydrogen) to ensure consumer price parity between natural gas and hydrogen.

Regarding existing regulations, despite the fact that (for the most part) these provide a strong and suitable fit to repurpose the gas grid, it remains unclear which organisations will construct and operate multiple national facilities to produce hydrogen with renewable electricity. Workarounds for demonstrators such as SPV companies and letters of comfort can provide learning, but that needs to be encoded into resilient subsidiary enactment, to enable multiple repurposing projects to arise during the mid-2020's, commencing 20–30 years of low-carbon gas infrastructure and delivery transition. Furthermore, diligence will be required to ensure synchronicity in any upscaled scenario when considering supply chains and maintenance, perhaps most notably the need for certified training programmes for hydrogen gas engineers along the supply chain.

In summary, and beyond the country specific regulatory issues we have mapped, this paper draws attention to several generic non-technical challenges to develop hydrogen gas grids. Existing (natural) gas supply network companies face termination unless they can switch to low-carbon gas. Apart from some small scale and local use of biogas (bioenergy being a constrained resource), this currently implies a switch to blue or green hydrogen. However, the innovation required places these same networks into a position of holding innovation risk, which their Regulated Asset Base model of business is ill-equipped to undertake. Concomitantly, questions still remain to what extent (fossil fuel) incumbents can be expected to drive forward green innovation and take more financial risk within an energy market that is regulated and a policy environment that is shifting towards decarbonisation. This suggests the potential for ongoing uncertainty given the longitudinal nature of transition (20–30-year timescale for gas infrastructure reorientation) vs the frequently shifting political landscape (5-year election cycles).

Pilot and demonstration projects of 100% hydrogen gas grids are needed to develop technical skills, test new equipment, push for the removal of redundant regulations of the natural gas age (unintentional barriers to low-carbon hydrogen) and build stakeholder and public confidence. Given the urgent need to decarbonise space and water heating in the built environment, and the current dominance of heat pump technology in the vision of how to achieve this, it makes sense for distribution network businesses to engage actively with (small, and therefore relatively affordable) hydrogen gas grid pilot projects. After all, these companies would not want to lose their business and see their assets stranded, i.e. their gas pipe system. But without government support and market intervention, it is difficult to see how the private sector could move from small pilot projects to larger scale, commercial deployment. The greater value of such pilot projects therefore lies in a progressive collaboration between the state and private sector, to develop strategic visions and environmental business cases for low-carbon hydrogen gas grids. This challenge is spatial because of the geographies of supply and demand, and temporal because grids are built gradually and may expand over time to serve new users at relatively lower connection costs. Potential business cases are strongest in locations of concentrated and guaranteed demand for hydrogen, especially industry (e.g. sectors like steel and cement which are hard to decarbonise by any other means). On a positive note for the company; this is where an innovative project could also prove to be a wise investment beyond its initial demonstration value. Once operational, a well-sited domestic sector hydrogen gas grid demonstration project could act as a hub for supporting local growth by de-risking the local value chain, making it more commercially viable to serve new local domestic and business customers, or a local hydrogen fuel station.

Author contributions

The work was sponsored by SGN. The investigation programme was designed by J-MC, CS, DvdH and ML; information gathering work and data analysis was carried out by CS, ML and DvdH. JMC performed complementary regulatory analysis and CS carried out the literature review. The manuscript was written by JMC and CS, with contributions and review from SH and DvdH.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests. We certify that any and all of our affiliations with, or financial involvement with, any organization or entity with a financial interest in or financial conflict with the subject matter or materials discussed in the manuscript will be disclosed in the funding acknowledgments section of this manuscript as follows: This research was funded by SGN under the Ofgem Gas Network Innovation Allowance fund. More information can be found on https://www.smarternetworks.org/project/nia_sgn0105. We also declare this funding source in the Cover Letter accompanying this submission.

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Appendix A. Supplementary data

Supplementary data related to this article can be found at https://doi.org/10.1016/j.ijhydene.2022.05.123.

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