HyNTS – Future Rollout Mapping

Final Report

10 September 2024

CONTENTS

ERM

ACRONYMS AND ABBREVIATIONS

Acronyms	Description
AC	Alternating current
artic	Articulated truck
bar	Unit of pressure
BEB	Battery electric bus
BEV	Battery electric vehicle
BODS	Bus open data service
capex	Capital expenditure
CILT	The Chartered Institute of Logistics and Transport
CPT	Confederation of Passenger Transport UK
CSRGT	Continuing Survey of Road Goods Transport
DC	Direct current
DfT	Department for Transport
duty	Duty cycle, defined as the sequence of trips performed by a vehicle, typically between leaving and returning to its depot
ETIS	European transport policy information system
FCEV	Fuel cell electric vehicle
GB	Great Britain
HGV	Heavy goods vehicle
HVO	Hydrotreated vegetable oil
HRS	Hydrogen refuelling station
LCOH	Levelised Cost of Hydrogen
JIVE	Joint Initiative for hydrogen Vehicles across Europe
kg	Kilogram
km	Kilometre
KV	Kilovolt
kW, kWh	Kilowatt (hour)
m	Metres

Acronyms	Description
MW, MWh	Megawatt (hour)
MSA	Motorway service area
NTS	National Transmission System
OEM	Original equipment manufacturer
opex	Operating expenditure
ORR	Office of rail and road
p	Pence
RSSB	Rail safety and standards board
SAF	Sustainable aviation fuel
t, t-km	Tonne (kilometre)
TCO	Total cost of ownership
TEN-T	Trans-European transport network
tpd	Tonnes per day
trip	One-way vehicle journey from origin to destination
TW, TWh	Terawatt (hour)
UK	United Kingdom

1. INTRODUCTION

1.1 CONTEXT

The HyNTS project aims to demonstrate the distribution of hydrogen through the National Transmission System (NTS) for hydrogen refuelling stations, enabling refuelling stations to secure hydrogen from low-cost, large-scale production facilities both during and after conversion of the NTS to 100% hydrogen. During the transitional period, hydrogen will be combined with natural gas up to a 20% volume in the NTS, with gases then separated or "de-blended" after transport along these pipelines, and then purified to fuel cell purity for use in transport applications. Even if the NTS converts to 100% hydrogen, purification and compression will still be required to get the hydrogen to fuel cell purity.

As part of the Beta phase of the HyNTS project, demonstration of de-blending technology is taking place at the FutureGrid site at Spadeadam. If successful, this could lead to larger-scale roll-out of this technology across the NTS. This report aims to identify potential locations for a first commercial demonstration of de-blending technology by considering the scale and geographical distribution of future hydrogen transport demands in relation to the NTS.

1.2 AN OPPORTUNITY FOR DEBLENDING

Hydrogen has, over the next two decades, the potential to emerge as a solution to decarbonise vehicles as an alternative to battery electric technology, particularly those modes of transportation that cannot be easily achieved with battery electric technology.

Transport operators will rationally defer these challenges but through decarbonisation targets – both those demanded by government, and by their own customers and financiers, will begin to act upon them. Opportunities for refuelling through the gas network are thus likely to both emerge and need to be seized within relatively short timescales of a few years. The hydrogen supply sector must be ready to respond to each opportunity when and where it arises, creating first-mover advantage rather than relying on full market maturity.

Consequently, existing gas network operators must be prepared to capture hydrogen supply opportunities as they arise in order to effectively support the transition from current natural gas markets to future hydrogen markets. However, hydrogen demand during such a transition will be lower than ultimately achievable as natural gas demand will continue. This makes a wholesale conversion of network infrastructure from one fuel to another infeasible in most cases. However, there will be some earlier opportunities for conversion of the infrastructure to 100% hydrogen pipeline, through planned projects such as Project Union, which is aiming to repurpose ~25% of the UK's transmission network by the early 2030s[1].

During the transition, deblending offers a solution to this transitional dilemma by blending hydrogen with the existing gas supply. The blending of hydrogen into the existing gas network is not the long-term aim, which is to convert pipelines to only hydrogen. Rather, deblending allows a smooth transition between current and, crucially, future markets that are contingent on such a transition. Consequently, deblending should be assessed primarily as a transitional cost, with its ultimate value being in the future market it opens for purification and compression.

[1] PowerPoint Presentation (energynetworks.org)

1.3 REPORT STRUCTURE

This report:

- Lays out where and when the best opportunities to supply hydrogen to the British transport sector are likely to emerge.
- Analyses the need for local scaling of future hydrogen demand and the extent to which demands need to be clustered.
- Assesses the cost of deblending against other hydrogen distribution options and evaluates the long-term risk of not adopting deblending.
- Proposes locations of future hydrogen supply hubs at which deblending equipment might initially be deployed.
- Discusses the risks associated with this opportunity.

2. RESULTS

2.1 ASSESSMENT OF POTENTIAL HYDROGEN DEMAND IN TRANSPORT

Hydrogen is emerging as a solution for vehicle operations that would otherwise be hard to decarbonise with battery electric technology. We define 'hard' as those battery electric solutions that would inevitably add cost, thus making total cost of ownership of hydrogen-powered vehicles relatively competitive. Capital and operating costs are key considerations for total cost of ownership and it must be noted that whilst capital costs for hydrogen solutions are likely to be broadly similar to battery electric solutions, operating costs may be impacted by higher fuel costs over electricity.

Potential future hydrogen demand is defined as that which would emerge if these "hard" decarbonisation challenges were solved with hydrogen solutions. In practice, hydrogen technologies are one of a range of possible measures. An assessment of the likelihood of hydrogen adoption in each use case is outlined as part of the risk assessment (section 2.3.3, towards the end of the main body of this report.

Our method, detailed in section 4, focuses on those modes of transport within Great Britain that have the strongest long-term potential. This includes:

1) **Aviation** – there is a potential role for hydrogen on long-distance domestic routes (specifically, liquid hydrogen fuel cell on turboprop routes >600km) with ZeroAvia and Loganair investing heavily in technology and advancements. However, it should be noted that significant technical and safety challenges exist. Shorter domestic routes are also likely to be served by battery electric aircraft and international routes with Sustainable Aviation Fuel[2]. Further detail can be found in section 4.2.
2) **Heavy Goods Vehicles** (HGVs) – there is a role for hydrogen for vehicles operating on the most long-route, high payload operations, where battery electric operation is more challenging. This includes articulated HGVs that cannot rationally utilise public charging mid-shift (for example, where two drivers per vehicle removes the need to stop for statutory rest breaks) and very long-distance trips,

[2] Hydrogen demand to produce Sustainable Aviation Fuel is not in the scope of this study.

including international HGVs. Further detail can be found in section 4.4. There are existing projects ongoing engaging this market, such as the HyHaul and ZEN Freight projects, funded under the UK Government's Zero Emission HGV & Infrastructure demonstrator programme.

3) **Local buses** – Already in use in Aberdeen and London, there is an existing role for hydrogen buses. Hydrogen buses are suitable where battery means extra cost and operational complexity, for example, on routes where opportunity charging or extra battery electric vehicles would be required to maintain existing passenger service patterns. This is most likely to occur on intensely operated local buses (typically those operating continually for most hours of the day and/or relatively high speed), such as interurban buses. Further detail can be found in section 4.5.
4) **Trains** – in the absence of Government commitment with regards to track electrification, the rail sector needs to consider second-best decarbonisation options. Here, hydrogen is a strong contender for freight trains because of the high-power requirements of heavy trains and the potential synergies with industry (hydrogen combustion for freight locomotives can directly use impure pipeline fed hydrogen anticipated in industry). There is also a potential role for hydrogen in long-distance passenger trains, where track electrification is minimal. Further detail can be found in section 4.6.

Other potential uses of hydrogen, notably in industry, maritime and non-road mobile machinery, are outside the scope of this study[3], although evidence of companies engaging with the hydrogen market has been seen by Liebherr and JCB.

Our approach focuses on long-term potential that might arise during the energy transition rather than short-term opportunities. This echoes the introductory rationale that deblending is a means of securing a long-term market that could yield value.

2.1.1 SCALE & TIMING OF DEMAND

Our assessments estimate a demand of circa 760 tonnes of hydrogen per day[4] across Great Britain in the scenario where all potential hydrogen demands are realised. Figure 1 shows how this total would be distributed for each mode of transport's operational sub-categories. Putting this into context of overall energy demand for each mode, in 2050, hydrogen is expected to make up a significant proportion of the overall energy demand for bus, coach and non-electrified rail, with only a modest contribution for aviation and HGVs[5].

[3] While demand locations may overlap, transport vehicles are most likely to use fuel cells which require a higher purity of hydrogen than most industrial applications. ERM analysis of non-road mobile machinery for the UK Department of Transport (https://assets.publishing.service.gov.uk/media/658443f3ed3c3400133bfd4d/nrmm-decarbonisation-options-feasibility-report.pdf) concluded hydrogen fuel cells solutions might abate only a small proportion of emissions were other options to be constrained. This, combined with low geographical agglomeration compared to other modes of transport, leads us to conclude that hydrogen potential in the non-road sector is unlikely to be as strong as those modes included here.

[4] Note, this is an order of magnitude less than the total transport demand estimated in the UK Hydrogen Strategy (publishing.service.gov.uk) (2021). The UK Hydrogen Strategy estimated between 75 and 140 TWh of hydrogen demand from transport by 2050, which corresponds to between 6 – 12 kt demand per day.

[5] The hydrogen demand potential corresponds to the following percentage of overall energy demand in 2050: *Bus and Coach*: ~50%, *Rail*: ~70% of all non-electrified rail energy, *Aviation*: ~25% of domestic aviation energy, *HGV:* ~10%.

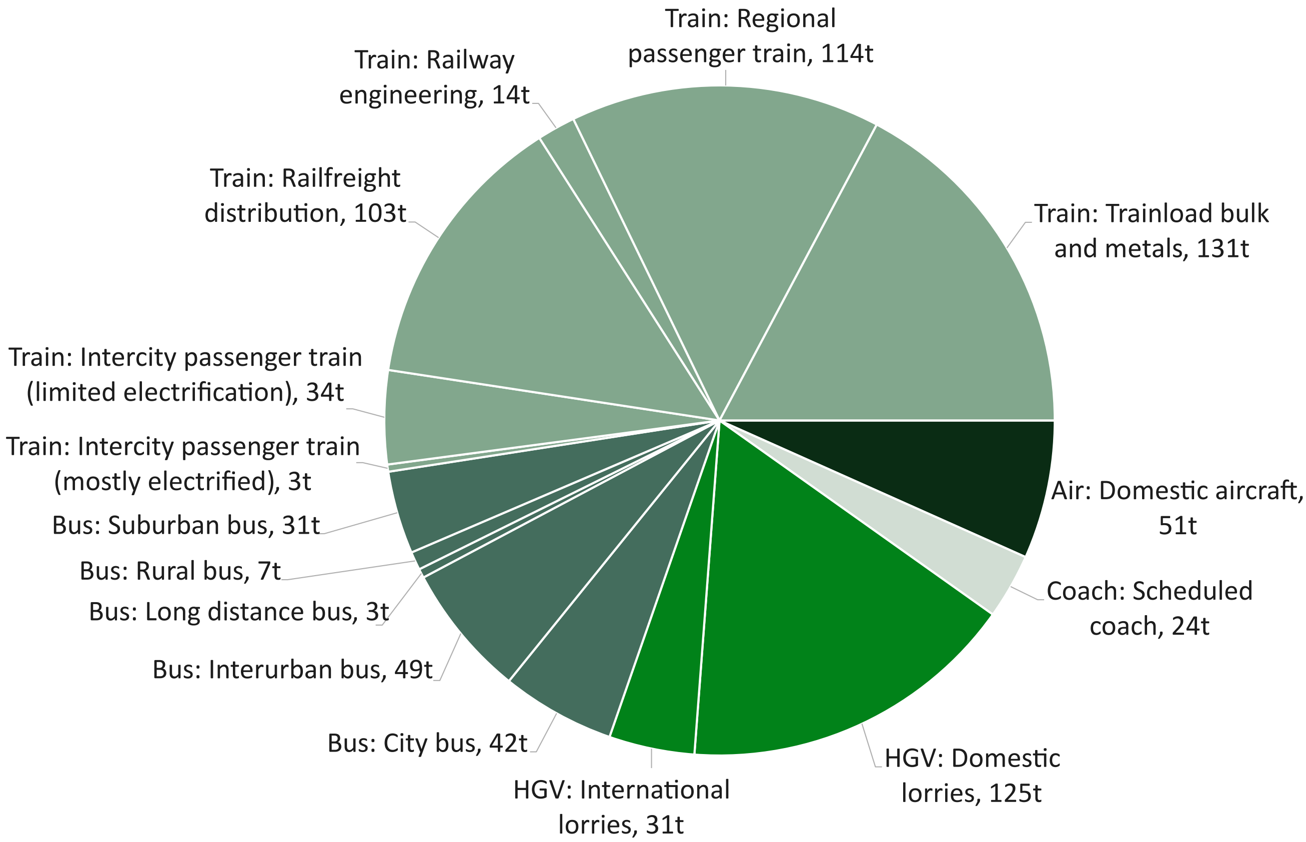


FIGURE 1: POTENTIAL DAILY HYDROGEN DEMAND IN TONNES, BY MODE AND DUTY CYCLE, IF ALL POTENTIAL DEMANDS TO 2050 ARE MET WITH HYDROGEN, GREAT BRITAIN.

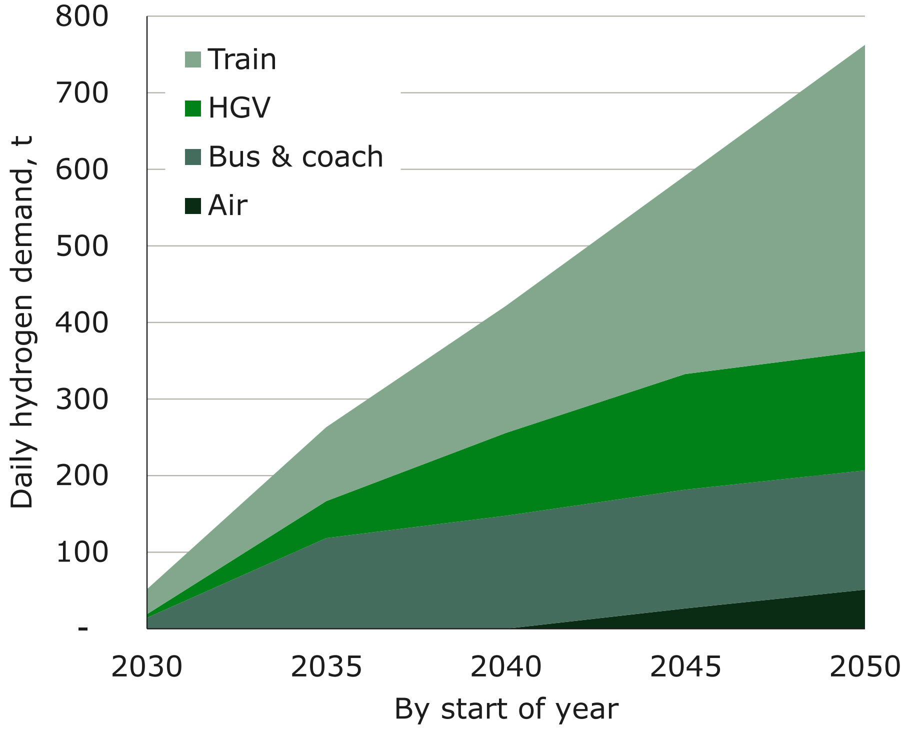


FIGURE 2: POTENTIAL DAILY HYDROGEN DEMAND IN TONNES, BY MODE AND YEAR, GREAT BRITAIN.

Transport operations can be expected to have varying timelines for decarbonisation between 2024 and 2050. The viability of hydrogen supply in each year of decarbonisation is critical so as not to impact the emergence of the overall potential market in 2050. Figure 2 shows the expected ramp-up of hydrogen demand over time, if all potential demands are exploited in the year they arise.

2.1.2 GEOGRAPHICAL DISTRIBUTION OF DEMAND

Demand for hydrogen in a given local transport operation for niche use cases is likely to be low, thereby creating the need to aggregate demand into local geographic clusters to ensure an efficient supply of hydrogen.

For example, a single heavy freight train operating from the Mendip quarries (Somerset) towards London could be expected to be fuelled with over 500 kg of hydrogen i.e., double the daily requirement for Passenger trains. In practice, the smallest railway fleets are likely to be efficient to supply.

In contrast, a hydrogen fuel cell bus might expect to use 25-30 kg of hydrogen daily, making local fleets of 10-20 buses relatively inefficient to supply with hydrogen. That being said, many current hydrogen bus operations do operate at this small-scale, such as the Perivale and Crawley stations.

To demonstrate the impact of these underlying patterns on the ease of hydrogen distribution, all potential demand, across all modes of transport, has been clustered into natural groups with no demand location more than 10km from another. The graphic below summarises the proportion of each mode’s total demand that would sit within a cluster totalling over 1 tonne per day. In practice almost all aviation and rail demand scales efficiently, while many road modes do not. This can be explained by the fact that the hydrogen demand per vehicle is significantly less for road transport modes compared with aircraft and trains.

FIGURE 3: PROPORTION OF EACH MODE'S DEMAND THAT FALLS WITHIN A LOCAL CLUSTER TOTALLING AT LEAST 1 TONNE PER DAY

Heavy Goods Vehicle (HGV) demand was modelled at home truck depot, but most such trucks would perform long-distance roles which may be served using enroute refuelling stations, especially at motorway service stations. Buses generally operate close to their local depot and would require fuel to be provided there.

As the pair of graphs below show, this scaling problem may be even more acute during the transition, with fewer large daily demand locations in the 2030s (in 2030, there are 8 clusters in Great Britain with demand > 5 tonnes per day whilst in 2050, there are 41 clusters with a demand > 5 tonnes per day).

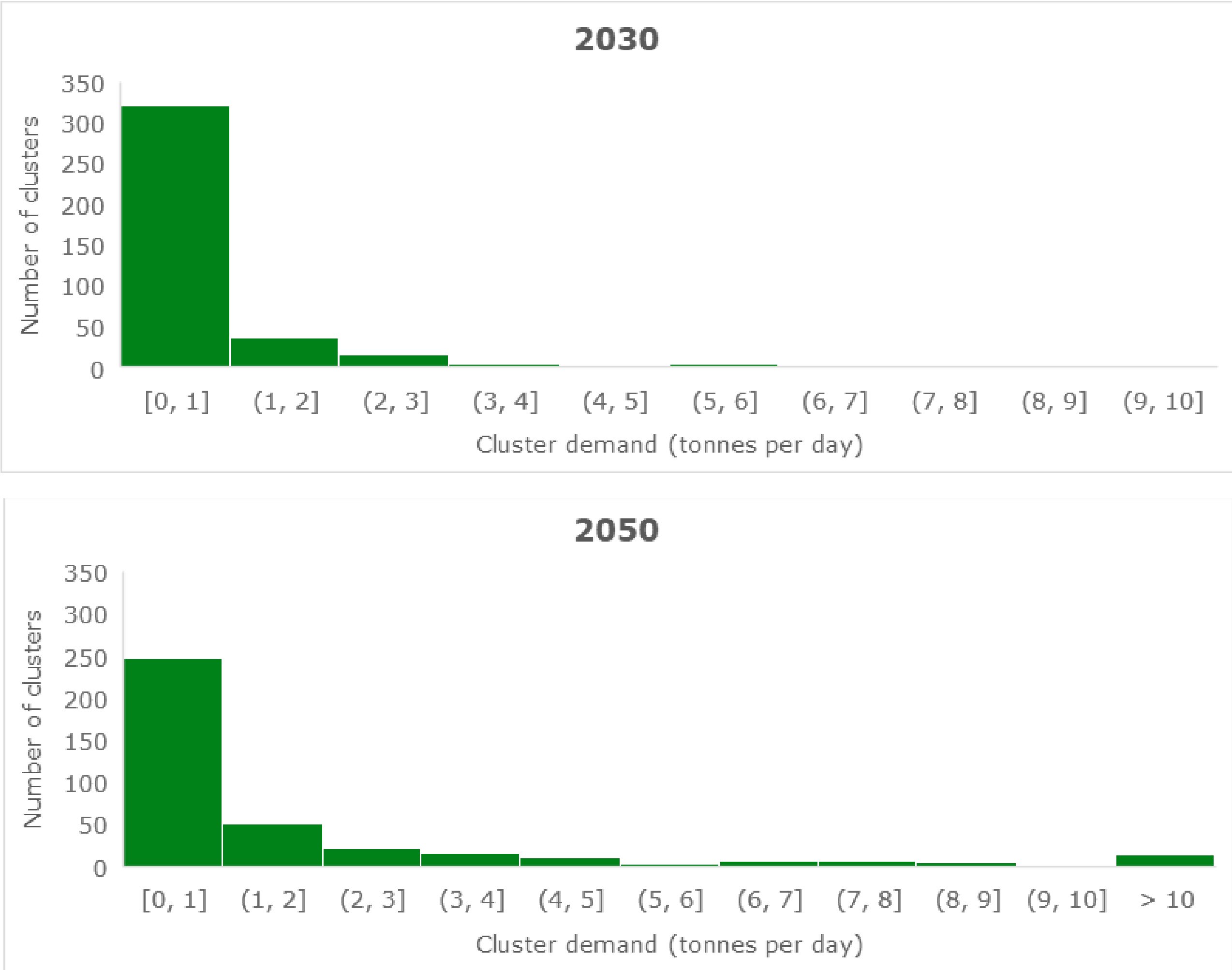


FIGURE 4: DISTRIBUTION OF LOCAL CLUSTERED DEMAND IN YEAR 2030 (TOP) AND 2050 (BOTTOM).

It is also interesting to consider the relationship between demand locations and the location of the NTS. Most transport systems and vehicles correlate strongly to human geography. However, the strategic distribution function of the current gas National Transmission System (NTS) is weakly correlated[6] to locations of potential hydrogen demand for transport.

The proximity of demands greater than 1 tonne per day to the NTS is shown in Figure 5 below. Figure 5 shows that many demands are less than 15km from the NTS, however, there are a small number of points that are much further from the NTS (>40km). Across all points, the mean distance to the NTS is 15km.

[6] For example, correlating volume of demand to distance to nearest point in the National Transmission System yielded an r-squared value of just 1%.

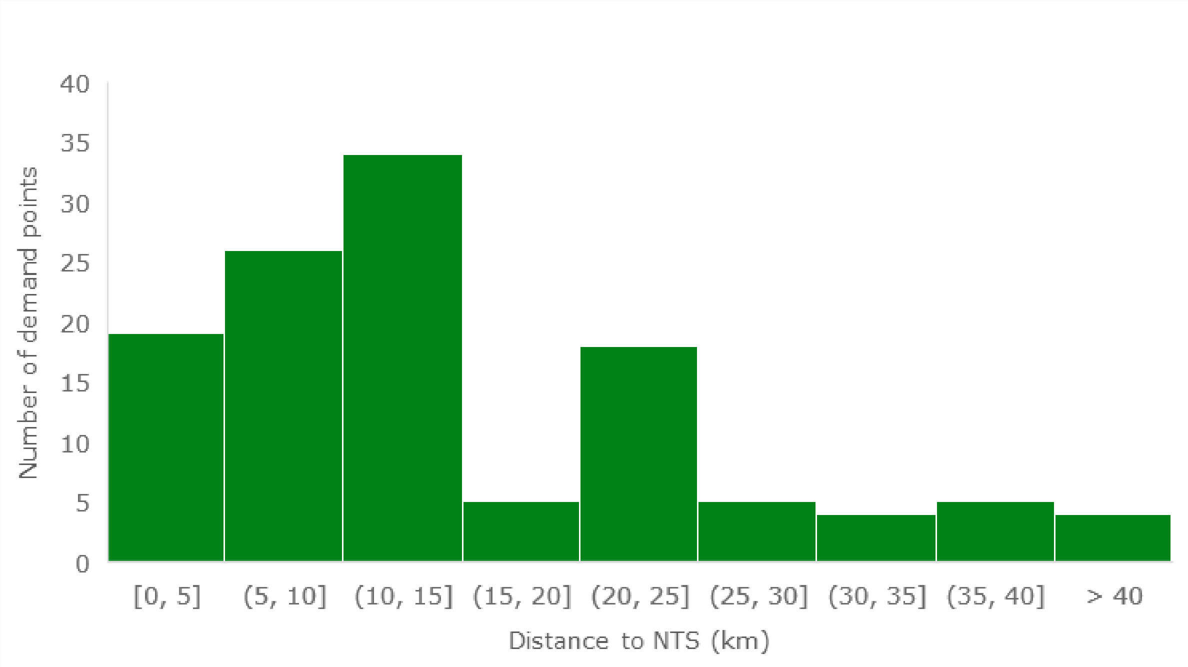


FIGURE 5: HISTOGRAM SHOWING PROXIMITY OF ALL DEMANDS TO THE NTS.

There are two logical consequences of the relationship between the NTS and demand:

- It may be advantageous to integrate parts of the local gas transmission system into the deblending and future distribution model, not to limit deblending to the NTS. This could complicate the business case, as long-run objectives, and abilities to manage financial risks may vary between partner organisations. This has not been explored in this report.
- There is a need to actively encourage regional supply hubs to be sited on the NTS – because hubs sited independently based on demand are unlikely to be placed close the NTS, and thus unlikely to ever be efficient to serve by pipeline.

The relationship between the NTS and transport demands is further highlighted in Figure 6 below, showing the distribution of large-scale demands (>5tpd) in relation to the NTS. Few of the 41 clusters fall within proximity of the NTS: fewer than 20% of clusters are within 5km of the NTS and fewer than 40% within 10km of the NTS. This is significant as proximity to the NTS will be one of the key factors in determining whether it is worthwhile to build new pipeline to make a direct connection to the NTS. This is explored further in section 2.3.2.

Another option where the distance to the NTS is not feasible, is to use the gas distribution network to reach these demands, however this facet has not been explored in this report.

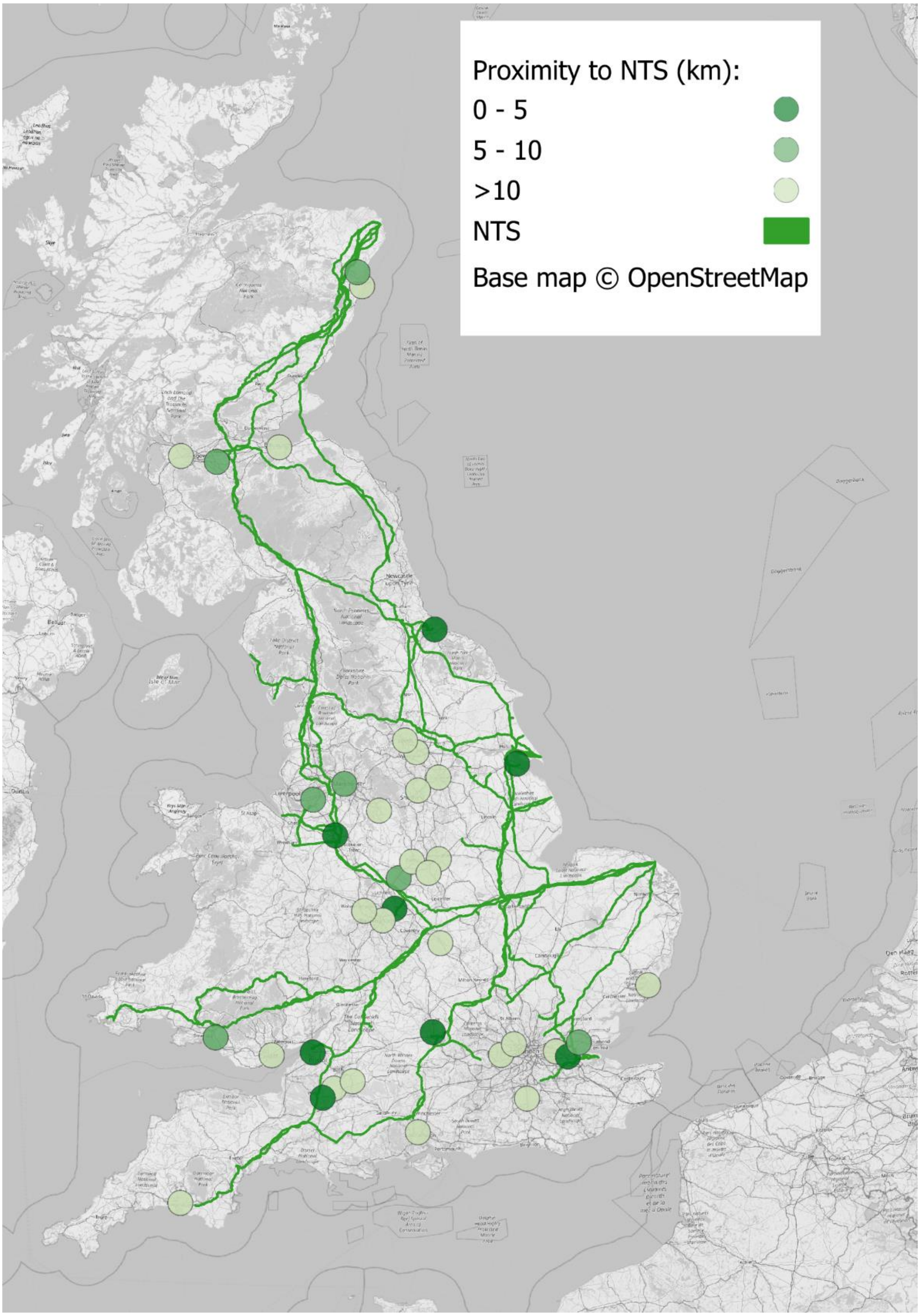


FIGURE 6: HYDROGEN MOBILITY CLUSTERS DEMANDING AT LEAST 5 TONNES PER DAY IN 2050, MAPPED AGAINST THE NTS (BASE MAP © OPEN STREET MAP).

2.2 COMMERCIAL ASSESSMENT OF DEBLENDING

Future hydrogen markets could emerge without reliance on pipelines, for example solely using long-distance road-hauled tube trailers. Once such distribution networks are established it could be difficult to convert to pipeline distribution, as facilities will not necessarily have been built in locations that suit pipeline connections. Therefore, the most efficient means of securing a future role for existing gas networks in hydrogen supply is to be core to the hydrogen distribution system as it develops while ensuring the most attractive supply locations are those already on the higher-pressure gas network.

As outlined previously, a gradual conversion of existing gas pipeline network for hydrogen distribution, aligned to an increasing demand for hydrogen, is critical. Most locations are served by just one high pressure pipeline, which therefore needs to transport a mixture of gases during the energy transition. This is the role of deblending.

Commercial viability should be assessed over two periods:

1. **Transition:** The period in which hydrogen is introduced to the gas network via blends. During the 25-year energy transition to zero carbon, the use of deblending technology can be expected to raise costs: both due to the technical inefficiencies inherent in any gas conversion process, and because low initial demand means low revenue with which to pay fixed costs. Cost increases cannot necessarily be all passed on to end customers without undermining the hydrogen market that the deblending technology is intended to both develop and capture.
2. **Long-term:** Once the conversion to a 100% hydrogen pipeline network is complete, purification and compression would still be needed to produce hydrogen at a quality suited for fuel cells, at lower cost to serve a mature market.

The key questions are whether any losses or opportunity cost (of investing elsewhere) that might be sustained in the first stage are countered by long-terms gains in the second stage. And ultimately, whether that difference can be financed as an acceptable risk.

In both phases, tube trailer distribution serves as a baseline for the prevailing cost of distributing hydrogen to transport sector end-users. This generalises two distinct approaches:

- Trailer distribution from a local supply hub, where hydrogen is created at the hub by electrolyser ("regional production"), and
- Trailer distribution from a major renewables-based production site, or associated land terminal or storage facility, most likely on the North Sea or Scottish coast, especially places where renewable generation exceeds electricity grid capability ("centralised production").

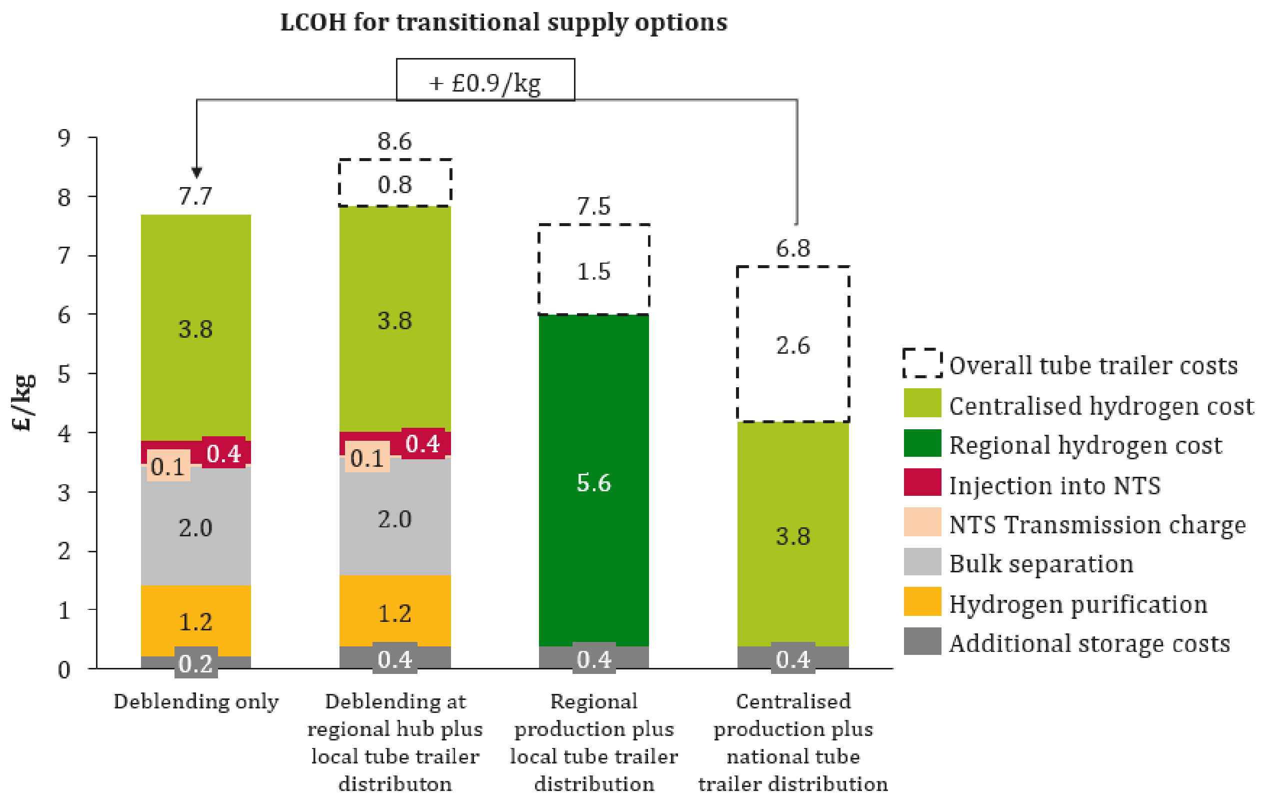
As discussed in the subsequent section, sites with smaller daily demands for hydrogen are unlikely to be served directly from the higher-pressure gas grid via deblending equipment. In these cases, a mixed model is anticipated, where deblending occurs at a regional supply hub, and trailers are used for more local distribution.

Six scenarios are thus analysed, four potentially available in each period (regional production plus local tube trailer distribution and centralised production plus national tube trailer distribution), as shown in the table below. Costs in the years 2040 and 2050 were used to reflect the transition and long-term views respectively.

TABLE 1: HYDROGEN SUPPLY OPTIONS ANALYSED[7]

Scenario	Transition	Long-term	Key decision factor
1	Deblending and purification-only	Hydrogen pipeline with purification-only	Size of end-user demand and proximity to NTS
2	Deblending and purification at regional hub plus local tube trailer distribution	Hydrogen pipeline with purification to regional hub plus local tube trailer distribution	
3	Regional production plus local tube trailer distribution		Price of remote renewable vs local electrolyser production
4	Centralised production plus national tube trailer distribution		

In this initial analysis, local and national tube trailer one-way deliveries are assumed as 50 and 250 kilometres respectively. Further assumptions are described in the appendix (section 6.1).



[7] Note, all pipeline-connected options are assumed to be supplied by hydrogen from a centralised production facility.

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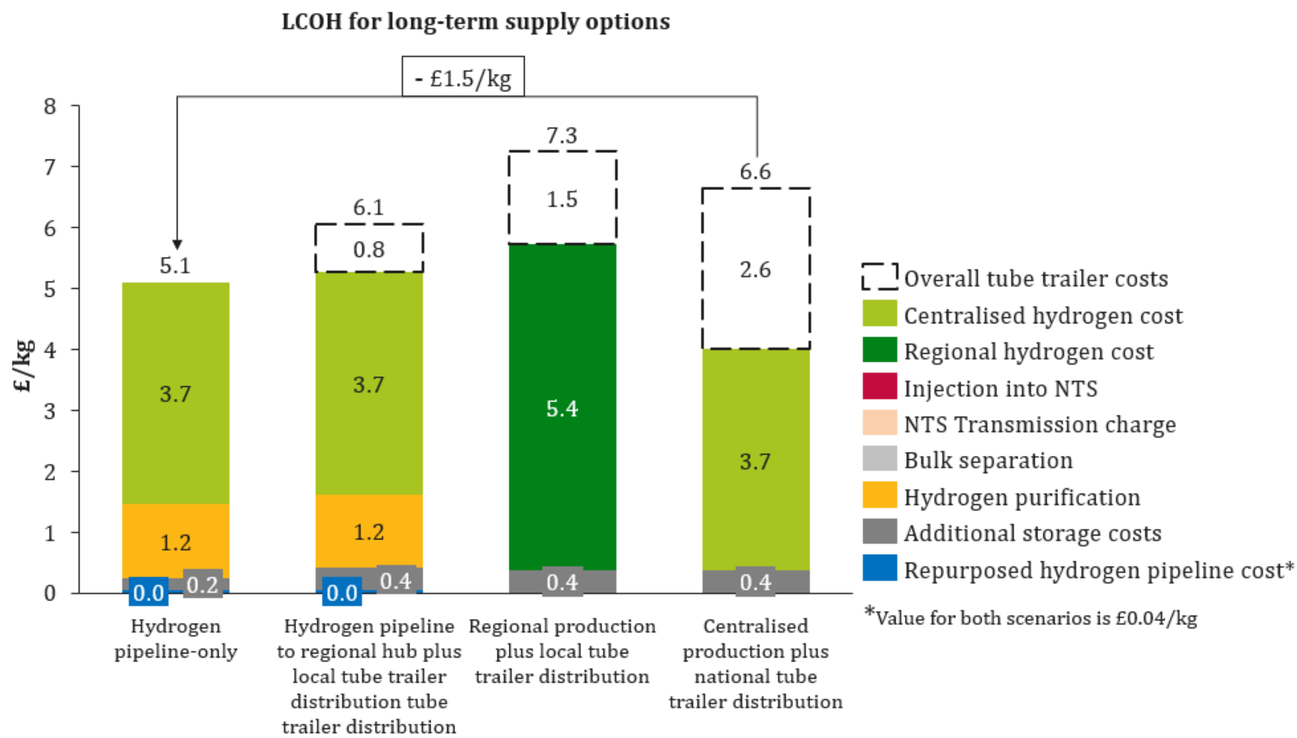

FIGURE 7: LEVELISED COST OF HYDROGEN (LCOH) ANALYSIS FOR SUPPLY OPTIONS. TOP: TRANSITION WITH DEBLENDING AND BOTTOM: LONG-TERM WITH DEDICATED HYDROGEN PIPELINE.

The graph above shows relative costs per kilogram of using each distribution option[8] during the transition and long-term. During the transition, deblending is unlikely to be a cheaper solution than the equivalent use of tube trailers from a centralised production facility (see top plot of Figure 7). However, in the long-term, dedicated hydrogen pipelines should be more competitive[9], especially for end-users close to the NTS (where limited new pipeline is required), as they can avoid the added costs of local tube trailer distribution (see bottom plot of Figure 7). The relative benefit of building new pipeline compared with last-mile tube trailer distribution is explored further in section 2.3.2. It should, however, be noted that the repurposed pipeline costs used in this LCOH analysis assume a large volume of hydrogen is being transported through the pipeline (on the order of thousands of tonnes per day). This level of demand cannot be achieved by the transport sector alone, hence, the long-term business case for transport is heavily reliant on other demands (e.g. heavy industry) materialising and also being served by the pipeline.

Figure 7 above implies that it is favourable to focus on demands that can be directly connected to the NTS, provided the cost of extending the pipeline is less than tube trailer distribution, since less subsidy will be required during the transition and the mark-up will be greater in the long-term. In this case, there is a need for a subsidy of at least £0.9/kg during the transition

[8] Overall tube trailer costs include trailer and truck CAPEX, fuel costs, driver cost and cost of compression into tube trailer. Hydrogen refuelling station costs are not included, since these apply to all options and will vary by location depending on local demand. The exclusion of HRS costs means this analysis underestimates the ultimate "price at the pump" of hydrogen.

[9] It should be noted that this cost analysis assumes that all parts of the NTS can be repurposed, rather than requiring new-build pipeline. Work is currently being undertaken as part of the Pre-FEED for Project Union to assess the extent to which repurposing will be possible. In the case that new-build pipeline is required, this could increase the cost by up to an additional ~£0.20/kg.

to remain competitive with road-only options, but long-term, a potential markup of up to £1.5/kg whilst being competitive against road.

Smaller daily demands, served from a hub with local tube trailer distribution, could still be competitive in the long-term – but with far lower markup. Those smaller demands would require greater subsidy during the transition, especially in later years when centralised production has been established. It will therefore be important to understand what proportion of potential demand might fall into larger single site demands that would be viable to connect directly. This question is addressed in section 2.3.2.

2.3 ASSESSMENT OF PIPELINE-SERVED HYDROGEN DEMANDS

Given the scaling challenges identified in section 2.1.2, the dominant mode of future supply is likely to involve the use of local tube trailers, not direct connection of end user to the gas network. Our approach is thus to frame a hub-based network, and then test the viability of that network if larger demand sites were removed and served independently with direct connections.

The first step was to cluster all potential demand into a sequence of hub sites with radius 100km. In practice, this range assumption would limit an out-and-back tube trailer delivery to about 250km, which is broadly achievable within a standard half-day driving shift of 4.5 hours. The central points generated by the clustering algorithm were then manually adjusted to nearby locations which would both sit on the NTS and be reasonably accessible from the strategic road network. A unique catchment with maximum 100km radius was then defined for each point.

For each of these hubs, initial analysis was carried out to understand the scale of demand, take-up profile of demand and breakdown of modes within each hub (see section 2.3.1).

Following this, further analysis was carried out to determine the optimal distribution option for individual demands within the hub, choosing between new-build pipeline to enable a direct connection to the NTS or tube trailer distribution from a centralised purification facility (see section 2.3.2).

2.3.1 TRENDS WITHIN A HUB-BASED NETWORK

Figure 8 provides an overview of the location, scale and timing of demand growth for each of these hubs with 100km-radius hinterlands. The size of the hub corresponds to its total potential demand in 2050. The largest demands tend to reflect the most populated areas of Great Britain, broadly London, Birmingham, Manchester and Yorkshire, with potential hydrogen demands of the order 100, 80, 70 and 70 tonnes per day respectively. At 100-km radius scale, there could be a total of 21 hubs across the Great Britain, however, the hydrogen demand in four of these hubs (all located on the fringes of Scotland) is expected to be so small (<2tpd total in 2050) that they cannot be seen in the figure – nor would such scale of demand be practical to serve by pipeline.

Figure 8 also illustrates the tendency of hydrogen demand to emerge earlier or later in the transition and how this varies between hubs. Blue indicates relatively steady growth of demand in the hub between 2025 and 2050, purple skews to earlier demand growth, and yellow skews to later demand growth. Early demand growth is seen in a limited number of locations (only Edinburgh and Plymouth), skewed primarily by the impending need to replace 1990s diesel railway rolling stock based in these locations. Most hubs skew to later demand growth (indicated by yellow clusters). Of the hubs with the greatest demand, the majority skew to later demand growth (London, Sheffield and Manchester), with some skewed to earlier demand growth in Birmingham.

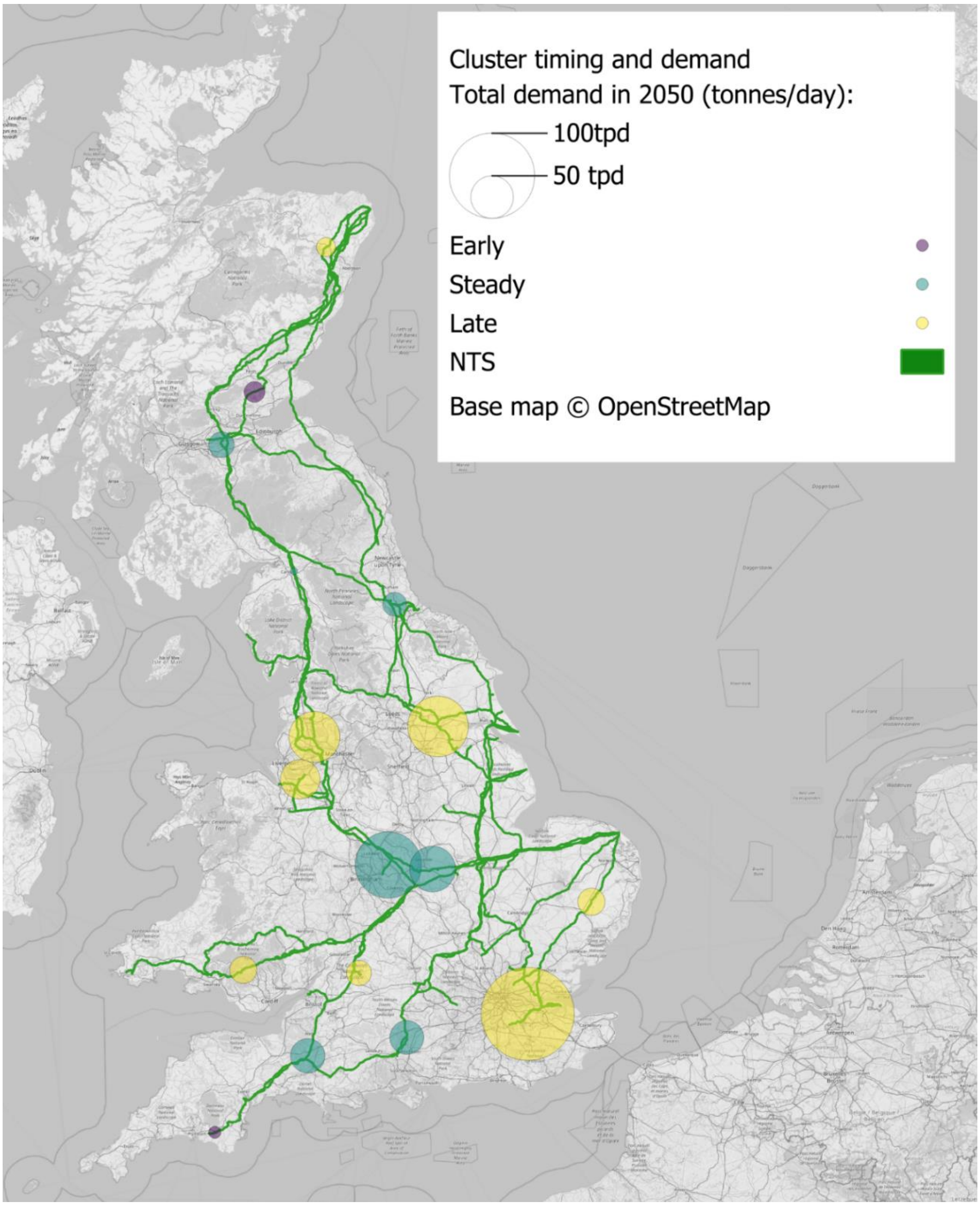

FIGURE 8: LOCATION, SCALE AND TIMING OF HUBS. HUB SIZE CORRESPONDS TO TOTAL POTENTIAL DEMAND SERVED, AND SHADING INDICATES THE TENDENCY FOR DEMAND TO EMERGE EARLY OR LATE IN THE TRANSITION (BASE MAP © OPEN STREET MAP).

The breakdown of modes within each cluster in 2050 is presented below in Figure 9. Trains make up a significant proportion of many of the clusters, with most of the remaining demand divided approximately equally between buses and HGVs. In practice, rail demands can only be served by refuelling facilities next to freight sidings or locomotive depots which may be poorly suited to fuel road vehicles, even if rail’s higher scale of demand appears to make it a viable "anchor demand" for other modes. Aircraft only contributes to demand in a small number of regions: London, Glasgow, Aberdeen, the main hubs for domestic aviation in the UK.

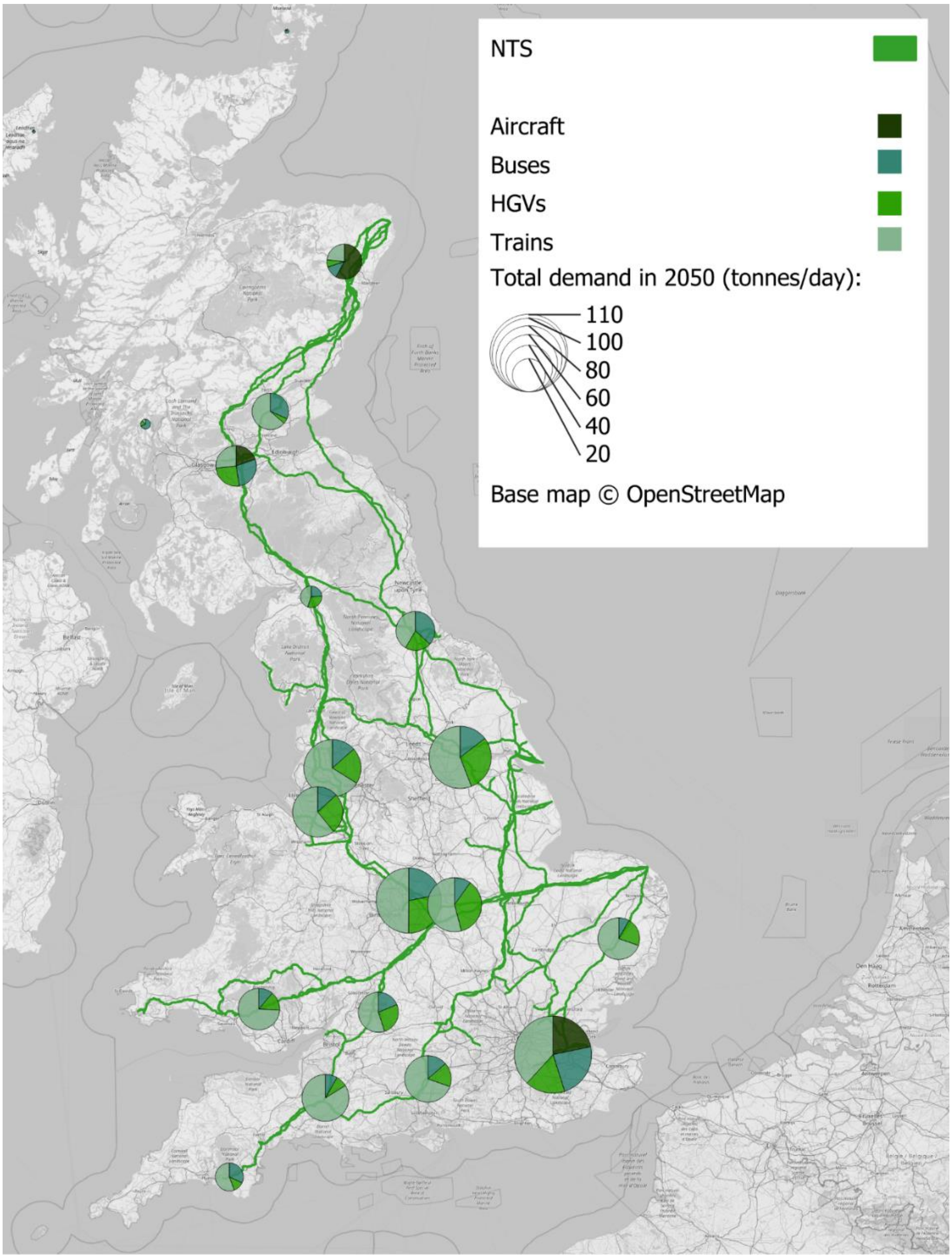

FIGURE 9: BREAKDOWN OF POTENTIAL DEMAND SERVED BY EACH HUB BY MODE (AIRCRAFT, BUS, HGV AND RAIL) (BASE MAP © OPEN STREET MAP).

2.3.2 OPTIMAL LAST-MILE DISTRIBUTION OPTION

As discussed in section 2.2, demands within each hub could either be served by (1) a direct connection to the NTS (which may require some new-build pipeline), or (2) tube trailer distribution from the hub. To determine the optimal last-mile distribution option, the cost of both distribution options was calculated for varying scales of hydrogen demand and distance from the NTS.

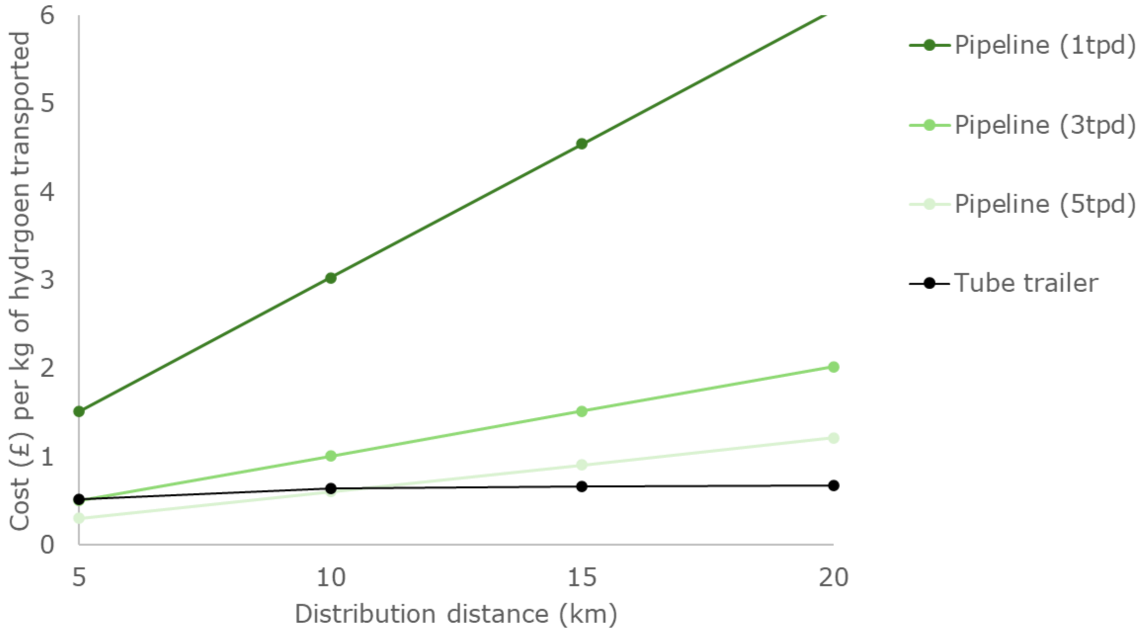

FIGURE 10: COST OF BUILDING NEW 100% HYDROGEN PIPELINE COMPARED WITH TUBE TRAILER DISTRIBUTION FROM A DEBLENDING HUB[10].

Figure 10 highlights that new-build pipelines may only be a preferable distribution option at short distances from the NTS and where large amounts of hydrogen are being transported. This contrasts to tube trailer distribution, which is less dependent on the distance of hydrogen transport (since the truck and trailer CAPEX, which makes up the majority of the cost, is less strongly correlated with the distribution distance).

Site-specific pipeline costing would be needed to determine whether building a new pipeline is commercially attractive. For the purpose of this analysis, it is assumed:

- For small demands (<3tpd), use tube trailer distribution
- For medium demands (3-5tpd), build a new pipeline if less than 5km from the NTS
- For large demands (>5tpd), build a new pipeline if less than 10km from the NTS

This leads to five different types of demand (based on demand size and distance from NTS) which can be assigned an optimal last-mile distribution method.

Demand size	Distance from NTS	Optimal distribution method
N/A	0km	Connect directly to NTS
Small (<3tpd)	N/A	Tube trailer
Medium (3-5tpd)	>5km	Tube trailer

[10] Note, this analysis assumes that for all volumes of hydrogen transported, the pipeline diameter is the same (0.1m).

Medium (3-5tpd)	<5km	Build pipeline for direct connection
Large (>5tpd)	>10km	Tube trailer
Large (>5tpd)	<10km	Build pipeline for direct connection

For each hub, a breakdown (by total demand) of the optimal distribution option is provided in Figure 11 below.

Given the limited number of large-scale demands in 2050 (41 in total, see section 2.1.1), the majority of the demand is best served by tube trailer distribution from a centralised purification facility. Once the demands served by direct connection to the NTS were removed, the total remaining demand of the hub was calculated to check the viability of the remaining hub: all hubs would still be viable, with a minimum demand of at least 1 tonne per day.

The results from this section will be used to determine the best locations to target for initial roll-out of deblending equipment in Section 2.3.4.

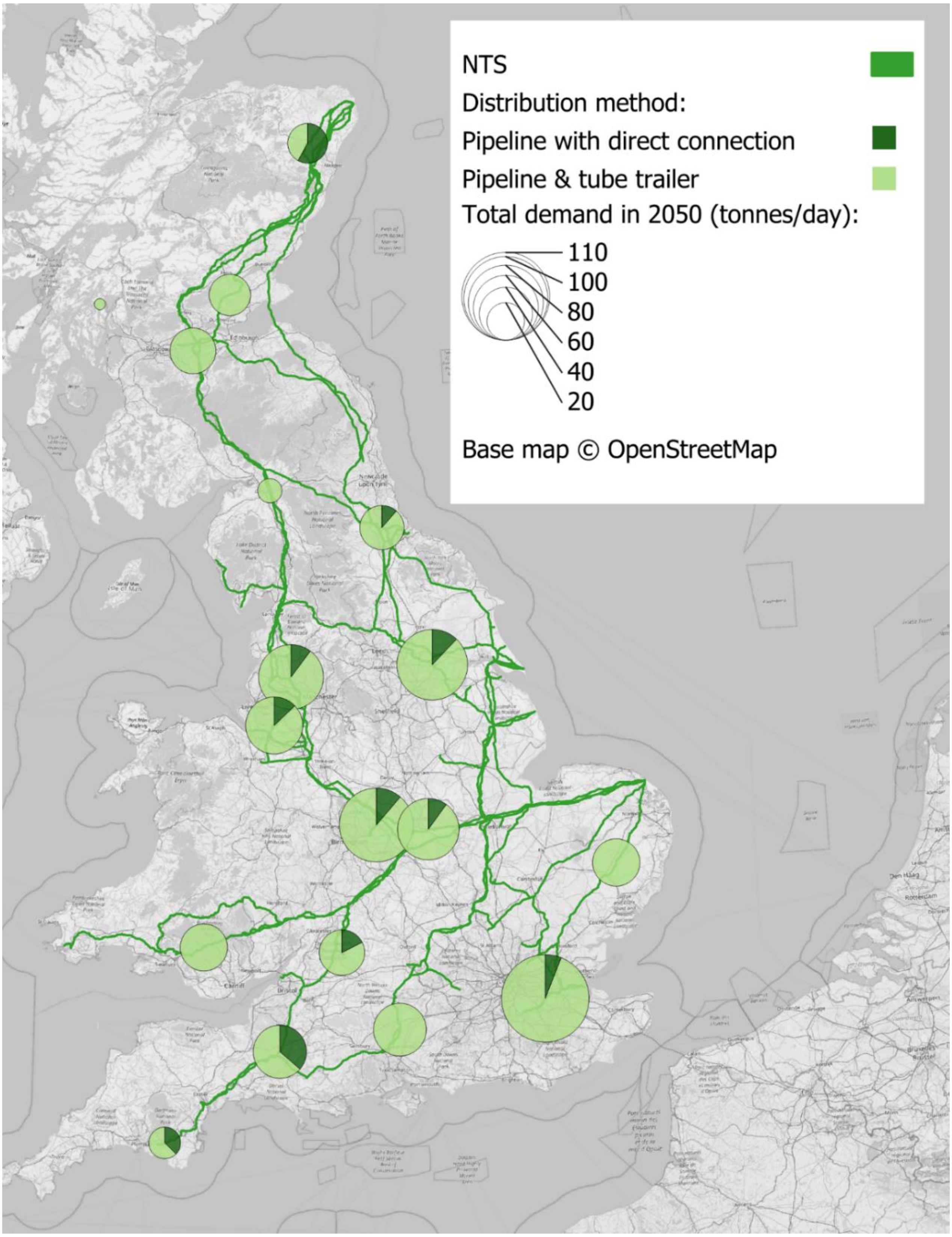

FIGURE 11: FRACTION OF HUB DEMAND IN 2050 SERVED BY DIRECT CONNECTION TO THE NTS COMPARED WITH TUBE TRAILER DISTRIBUTION. PIE CHART SIZE IS SCALED TO OVERALL HUB DEMAND IN 2050 (BASE MAP © OPEN STREET MAP).

2.3.3 RISK ASSESSMENT

Whilst future demand for hydrogen in the transport sector is inherently uncertain, the certainty of each demand has been quantified and split into three broad risk categories, as shown in the figure below. Moderate risk approximates to a 50-50 chance, while very high risk is estimated as no more than a 20% chance of occurring.

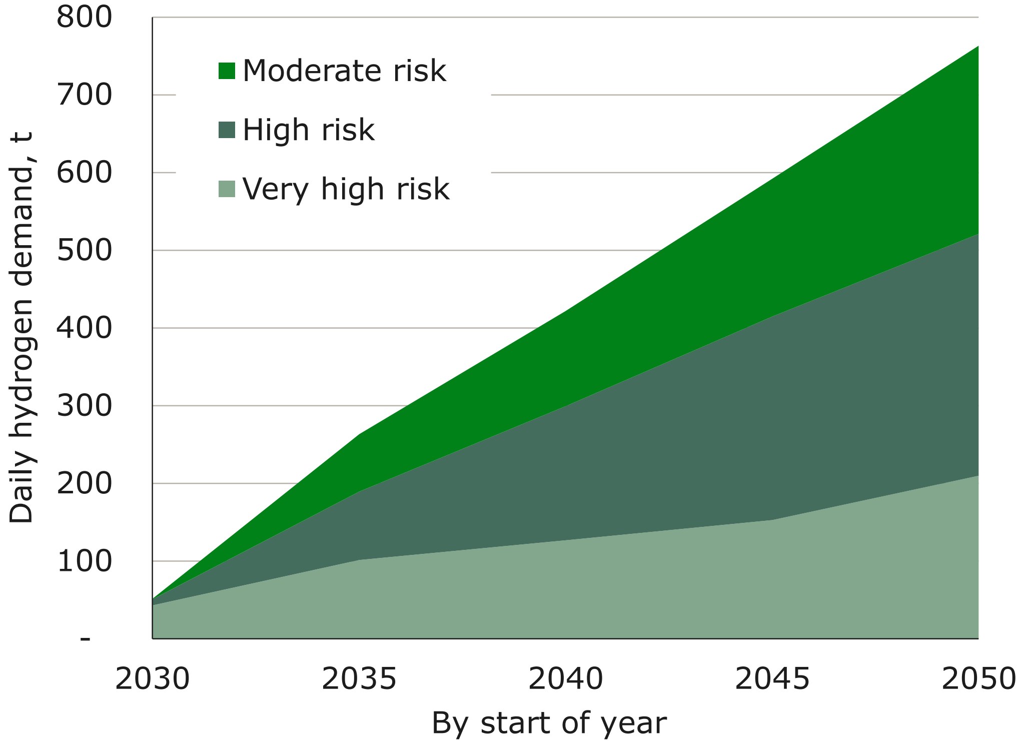

FIGURE 12: HYDROGEN DEMAND FROM TRANSPORT BY RISK VS DECARBONISATION ALTERNATIVES.

Much of the future hydrogen demand is highly uncertain, falling into the 'high' or 'very high' risk category. For each mode, a summary of the risks of the projected hydrogen demand materialising is provided below, and discussed more fully in section 4:

- Aircraft
  - There are safety concerns associated with using liquid hydrogen in aviation. Overcoming these challenges requires design, demonstration, and certification of new aircraft, which is anticipated to take several decades.
  - Hydrogen will serve a niche domestic 600+km market between battery and SAF. It is possible this demand will not materialise if the business case for hydrogen does not have any long-term advantage over SAF.
- Bus (see section 4.5.5):
  - The most likely hydrogen demands tend to reflect rural provision (including interurban services). This may need greater public subsidy to offset higher cost of hydrogen.
- Coach[11]:

[11] Scheduled coach has been included within the overall hydrogen demand modelling, but because of its long-distance nature, could not be reliably allocated to local hydrogen demand clusters. Tour and group hire coach has not been analysed.

 - Leisure travel is often price sensitive, rather than time sensitive, which means operators are less likely to be able to charge passenger extra to maintain the operational flexibility of hydrogen to provide long-distance journeys with minimal delay for fuelling.
 - The coach sector expects to follow the truck sector in terms of infrastructure requirements.
- HGVs (see section 4.4.5):
 - Scale of production for European OEMs is unlikely to be high enough to be cost-effective, leading to higher unit Capex for these vehicles.
 - Fuelling infrastructure for this sector is the hardest to scale geographically.
 - International trucks could transit Channel in trailer-only form and use only battery electric tractors within Great Britain.
- Trains (see section 4.6.4):
 - Emergence of a market for hydrogen in this sector will be impacted if Government commits to significant (i.e., *hundreds* of miles of) track electrification.

In earlier sections, the hydrogen demand values provided did not take into account the risk that demands may not emerge, but instead, helped to give a sense of the total potential hydrogen demand in any given year. The reasonable expectation of demand will depend on the breakdown of modes within each hub (with hydrogen demand more likely to emerge for some modes compared to others). This is an important factor in determining the suitability of a hub for rollout and is discussed more in the following section.

2.3.4 ROLL-OUT MAPPING

To determine which locations are best suited for a first commercial demonstration of deblending technology, several factors need to be taken into consideration. Firstly, the scale of the opportunity associated with each hub. This can be assessed by calculating the total potential demand in 2050 weighted by the certainty of this demand emerging (more detail in Section 2.3.3) to give a more reasonable estimate of demand in 2050.

Following this, the type of distribution method for demands within the hub needs to be considered. As discussed in Section 2.1.2, the priority should be on demands that are commercially viable to connect directly to the NTS in the long-term (large-scale demands close to the NTS), as they require a lower subsidy during the transition and higher mark-up in the long-term. In contrast, demands that will be served in the long-term by tube trailer distribution from a centralised purification facility may require significant subsidy to support deblending in the medium-term, making this option less attractive.

Therefore, as a first estimate of the suitability of different regions for a first commercial demonstration of deblending equipment, the total weighted demand of each site in 2050 was calculated (for each demand within a hub, total potential demand was multiplied by the certainty and weighted by the distribution method, with preference given to NTS-connected sites). The results are presented in Figure 13.

Figure 13 shows that the regions with the greatest suitability are London and Yorkshire, with Manchester, Birmingham and the South West close behind. Full detail on each of these sites (total potential demand, total weighted demand, fraction of demands directly connected vs tube trailer connected and breakdown of modes) is provided in section 6.2 of the Appendix. Specific sites for a first commercial demonstration have been identified in section 2.3.4.1.

Although Figure 13 provides a high-level assessment of the suitability of each hub for a first commercial demonstration, there are several additional factors that will be important for National Gas to consider. First, given that in the long-term, the repurposed pipelines will be used by both industrial and transport end users, the proximity of hubs to industrial demands should be considered, with priority given to hubs in close proximity to industrial demands. Second is proximity to large-scale centralised production facilities, which are likely to be concentrated around regions with high renewables availability, such as Aberdeen, Yorkshire and the East of England (See section 2.3.4.1 for detail). In this report, hubs are assumed to be a significant distance from these production facilities, which tips the business case in favour of pipeline distribution of hydrogen rather than tube trailer distribution. However, if hubs are located nearer to these production facilities, tube trailer distribution may be the more commercially attractive option.

The locations recommended for a first commercial demonstration in this report are based on future hydrogen demand modelling, which considers the ease of decarbonising different transport operations. An alternative approach is to consider the locations of existing and planned hydrogen refuelling stations as potential locations for a first commercial demonstration. This has not been explored in detail but a comprehensive list of these sites and their location relative to the NTS is provided in section 5.

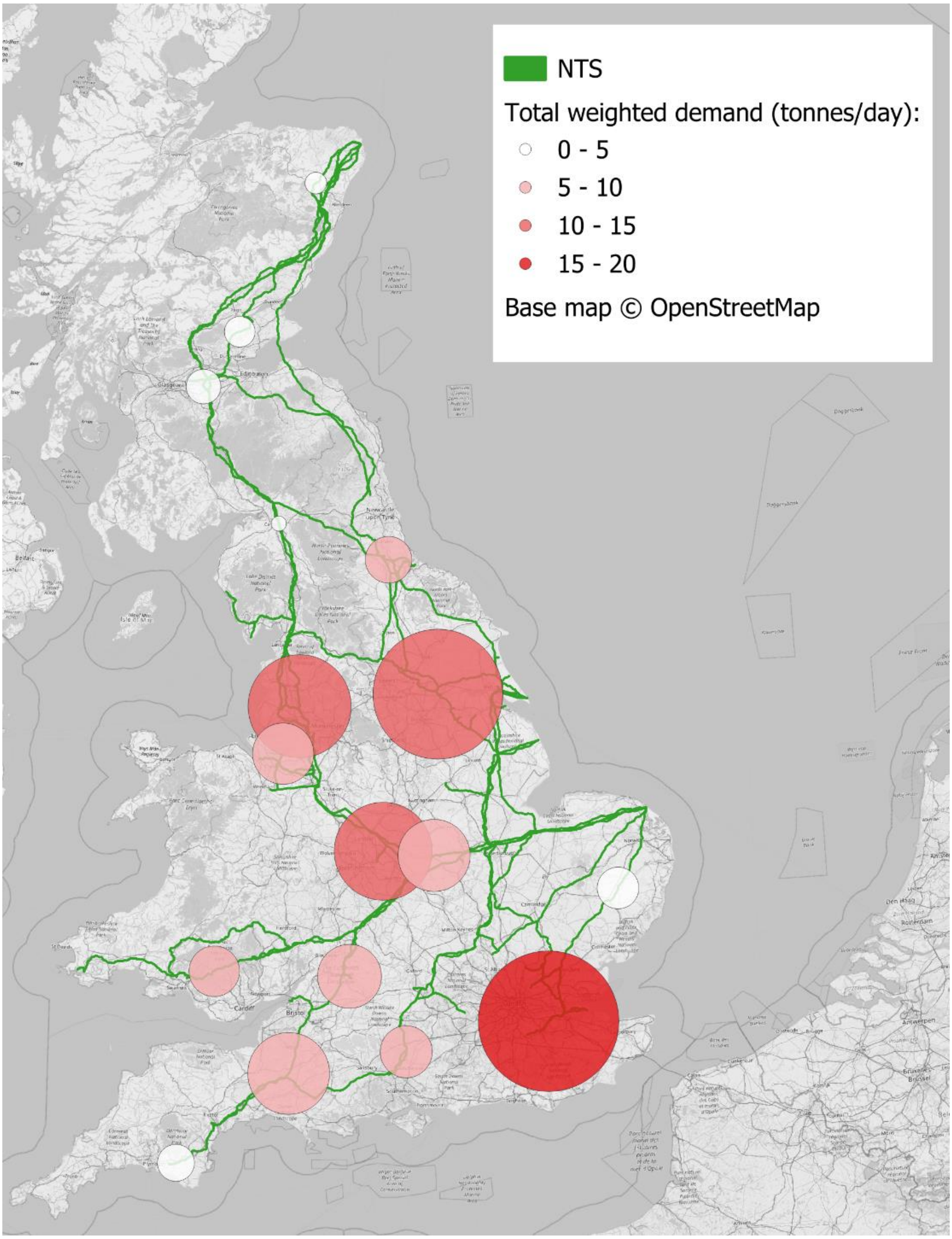

FIGURE 13: TOTAL WEIGHTED DEMAND FOR 100KM RADIUS HUBS IN 2050. HUB SIZE AND COLOUR ARE SCALED TO THE TOTAL WEIGHTED DEMAND (BASE MAP © OPEN STREET MAP).

2.3.4.1 SITE-SPECIFIC ASSESSMENT

To determine which specific sites to target for initial rollout of deblending, it makes sense to target those with large-scale potential for hydrogen demand. Rail is the obvious mode that has many sites with potential to create large-scale hydrogen demand and will therefore be the focus of this site-specific assessment. It is also useful to note that many of the operations are provided by the same companies (e.g., for railfreight, GB RailFreight, DB Cargo and Freightliner are the key players). Local railfreight operations vary in the extent to which they are self-contained, and the extent to which small, uniquely fuelled locomotive fleets might be viable. This means it will be advantageous to approach potential hydrogen deployment by railfreight sector, not just specific high demand sites.

The key sites to target for trainload bulk and metals (especially aggregates) are shown in **Error! Reference source not found.**Table 2 below. Note that sites that are currently used in polluting industries with limited long-term potential (e.g. oil refineries and coal production) were excluded from this list.

TABLE 2: LIST OF TRAINLOAD BULK & METALS SITES TO TARGET FOR FIRST COMMERCIAL DEMONSTRATION.

Site	Potential demand in 2050 (tonnes)	Certainty	Distance from NTS (km)
Dove Holes Quarry, Buxton[12]	18	50%	35
Whatley Quarry, Somerset	9		14
Port Talbot Steelworks	8		14
Torr Works Quarry, Somerset	7		10
Wembley, London	5		24
Hanson Concrete, West Acton	5		26
Barking Eurohub, London	3		11
British Steel, Scunthorpe	3		9

The key sites to target for railfreight distribution (primarily intermodal, including maritime containers) are shown in **Error! Reference source not found.**Table 3 below. Many of the locations shown are ports where freight begins its journey towards large cities in Britain. It is worth noting that there may be some flexibility on where these freight locomotives could be refuelled, with the possibility of refuelling en route, which could align better with the NTS, but this would vary by individual railfreight operator and would imply alteration to current operating behaviour.

TABLE 3: LIST OF RAILFREIGHT SITES TO TARGET FOR FIRST COMMERCIAL DEMONSTRATION.

Site	Potential demand in 2050 (tonnes)	Certainty	Distance from NTS (km)
Port of Felixstowe	14	30%	33
Port of Southampton	8		12

[12] Currently a key supplier to High Speed 2, a short-term end user whose supply is disproportionately suited to rail distribution, implying long term demand will be lower.

Site	Potential demand in 2050 (tonnes)	Certainty	Distance from NTS (km)
London Gateway Park	6		4
Manchester Container Terminal	6		8
Daventry International Rail Freight Terminal (DIRFT)	5		9
Eurocentral Mossend, Coatbridge	4		7
Port of Southampton	4		13
Hams Hall Rail Freight Terminal	3		1
Teesport	3		3

3. CONCLUSION

This report considers the possibility of serving future hydrogen transport demands by pipeline distribution. Two pipeline distribution scenarios were considered: directly connecting demands to the NTS (which may require some new-build pipeline) and tube trailer distribution from a centralised deblending hub.

A commercial assessment of the different distribution options highlighted that there is a case for pipeline distribution of hydrogen, but that deblending would need to be subsidised during the transition. Considering the two different pipeline distribution scenarios: directly connecting to the NTS is commercially favourable for large-scale demands in close proximity to the NTS. However, few demands fall into this category. Furthermore, many of these large-scale demands are rail demands, with uncertainty about whether this demand will emerge in the future (depending on Government’s decision on track electrification). Therefore, it is anticipated that many demands will be served by tube trailer from a centralised deblending facility. This scenario could be competitive in the long-term but with lower markup than direct connection to the NTS and requiring greater subsidy during the transition.

Beyond the commercial case, there are several other benefits to distribution via pipeline that are important to highlight. Firstly, pipeline distribution allows end users to access hydrogen supplied from multiple sources which increases the reliability of hydrogen supply. Additionally, the on-site footprint of direct pipeline options is smaller than tube trailer distribution.

Considering the scale and certainty of demand in each region and the preferred last-mile distribution method, the recommended regions to target for a first commercial roll-out of deblending equipment are London and Yorkshire, with Manchester, Birmingham and the South West close behind. Further consideration of the proximity of these regions to centralised production facilities and industrial demands is recommended in order to further shortlist these regions.

4. APPENDIX: HYDROGEN DEMAND MODELLING

4.1 COMMON METHOD

4.1.1 APPROACH

Our approach emphasises:

- **Clusters**: Efficient hydrogen supply requires scale locally, typically a minimum of hundreds of kilograms per day. Transport demand, especially from road vehicles, may need to cluster across multiple modes and operators to ensure cost effective supply. Modes with higher single location demands can still provide the local "anchor" demand for modes with lesser needs, hence are still included in the clustering logic.
- **Potential**: There is no clear trajectory for hydrogen transportation. Our first aim is to frame and locate the upper limits of direct demand, excluding demands where hydrogen has no realistic role. Within each category of mode and vehicle activity, the likelihood of hydrogen being adopted vs alternatives is assessed. Technology advancements have been considered as part of the modelling.
- **Practicalities**: The practicality of rollout has to be considered. Poor production efficiency means hydrogen will be a more expensive fuel than electricity. The key question is therefore "What vehicle activity cannot convert to battery electric without excessive extra cost or operational complexity?" Demand derived from hard-to-battery-electrify vehicle duties is modelled in the year period those vehicles are most likely to convert to zero emission.

The modelling method focuses solely on transport operational challenges, from the long-term perspective of the transport operator. Many advantages of hydrogen to the energy distribution network have no explicit impact on long-run fuel cost, and thus are not likely to be considered advantages by transport operators, notably:

- Transport operators have largely fixed demand for fuel from day-to-day, so cannot take direct advantage of periods of plentiful renewable energy production by simply operating more in those periods. Any advantage hydrogen has in storing energy will therefore manifest only in annual average fuel prices.
- There are short-term transitional challenges relating to depot conversions that are faced regardless of the technology deployed. For battery electric vehicles, operators may face challenges securing electricity grid connections. Equally, there are practical challenges to depot conversions to hydrogen, for example, relating to on-site storage regulation. In the long-term, these challenges will be solved, therefore, the modelling method has no regard for these practicalities.

Demand modelling was based around the place each vehicle duty starts. For many transport operators, hydrogen's appeal is that vehicles can be fuelled rapidly at the start of their working day without further refuelling. We expect the overwhelming proportion of any hydrogen fuelling to occur at or near home depots or hub terminals. This approach supposes that strong home demand will always be at the heart of any hydrogen refuelling facility, with any residual demand from en-route fuelling offered by such facilities on a marginal basis.

To ease the understanding of the core topic of modelling – the suitability of operations for hydrogen – current operations are simply assumed to continue in future years. In practice many modes of transport have ambitious growth targets, for example at least a 75% increase in railfreight by 2050[13]. Such policy aspirations of growth add uncertainty, especially for modes with no history of substantial growth in the previous 25 years. Any future uplift is most likely to scale up existing operations because the underlying geography will remain similar, so analysts may wish to simply multiply the hydrogen potential modelled here by whatever growth factor they consider reasonable.

4.1.2 DUTY CYCLE ASSIGNMENT AND LOCATION CLUSTERING

The method applied to each mode varies as detailed in subsequent mode-specific sections. However, all share the same broad approach shown in the flow chart below. A duty cycle is a sequence of trips conducted by a vehicle, typically between leaving and returning to its depot, typically over the course of one day. A trip is a one-way vehicle journey from origin to destination. A duty thus broadly defines the current diesel, and likely future hydrogen, fuelling requirements of each vehicle.

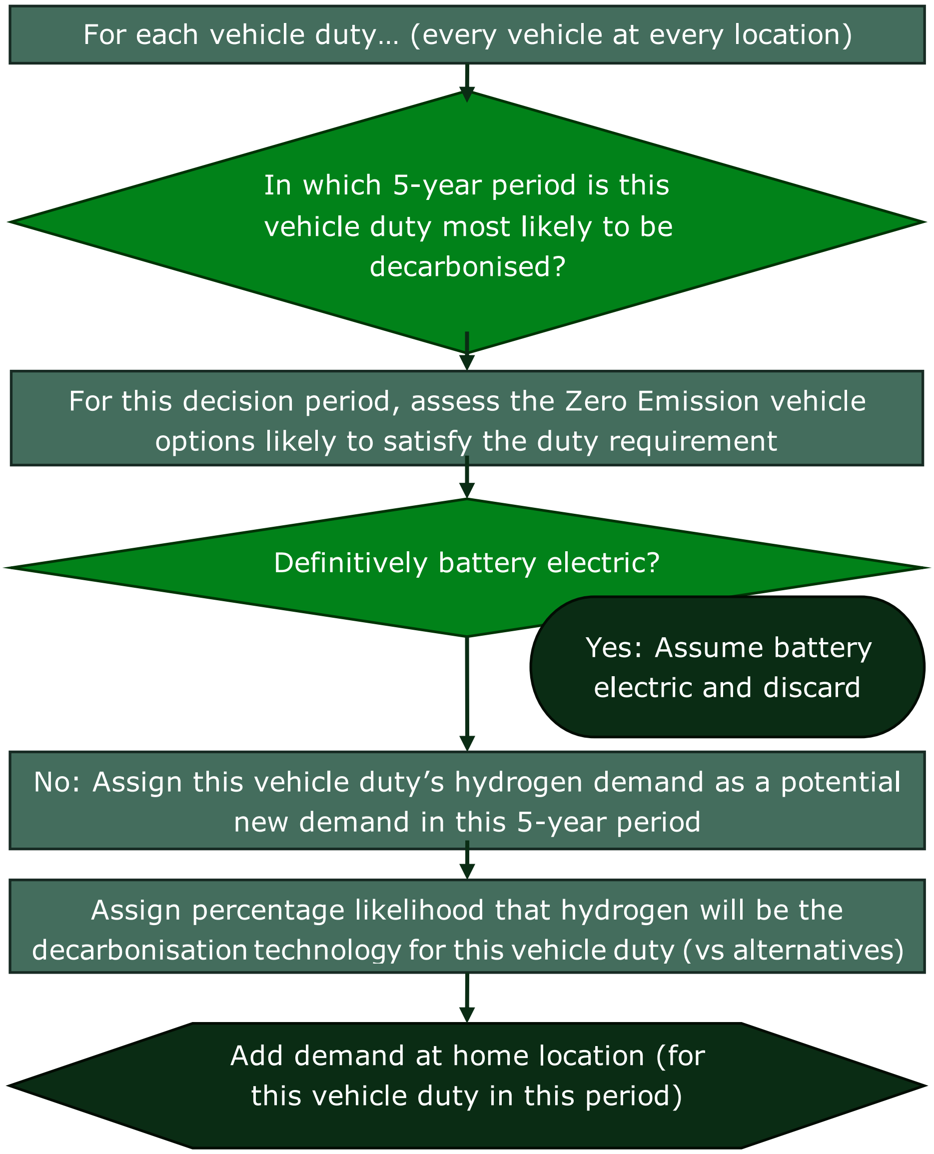

FIGURE 14: COMMON VEHICLE DUTY CYCLE ASSIGNMENT LOGIC

[13] https://www.gov.uk/government/news/government-sets-ambitious-target-to-grow-rail-freight-by-at-least-75

The risks assessed apply to the whole vehicle fleet for each duty cycle. Specific local factors are not considered within this assessment of risk. For example, a location modelled with a high total daily demand may as a result be more cost-effective to supply to, lowering costs and making the selection of hydrogen more likely. However, that total may require many local partners and vehicles duties to cooperate, an outcome which cannot be known.

The full set of demand locations were then clustered together using a SciPy hierarchical clustering algorithm. This algorithm gathers locations together, such that all are within a circle of radius 5 kilometres.

Where multiple demand locations have been clustered, the visible centroid of each cluster may not relate to any one site, or even land where a common site might be possible to build. Clusters are intended as indicators of demand within a local area – not precise locations for refuelling infrastructure.

Clusters may total any volume of potential demand. In practice, the most basic hydrogen refuelling station will require several million pounds of capital investment, which is unlikely to be viable to serve the smallest clusters of demand. Hydrogen refuelling stations are currently several times more expensive to build than an equivalent diesel facility[14], although costs are expected to drop as the technology matures.

In all cases it was assumed that local transport infrastructure will be sufficient to keep all individual locations within an acceptable distance of a notional central refuelling hub connected.

The acceptability of this distance was calibrated against the observed average dead mileage (between depot and start/end of bus route) of large bus operators, using data assembled for the local bus method. Dead mileage currently adds 4-5% to mileage in passenger service. This figure rises to an average of 16% for the smallest groups and independent bus operators, which suggests even more distant trips to fuel may still be viable.

Daily vehicle duties with genuine potential to adopt hydrogen tend to be over 200 kilometres, so adding around 3 kilometres for fuelling is in the order of 1%, which will be an insignificant mileage increase in most cases. In practice each vehicle may not need to drive to a shared refuelling facility each day. For example, supplying hydrogen could involve the use of short-distance road trailers to serve depot-specific compressors to allow refuelling within individual depots.

4.2 AIRCRAFT

4.2.1 CONTEXT

Despite neither the Climate Change Committee (CCC) 6th carbon budget nor the Department for Transport including any role at all for direct hydrogen use in modelled scenarios[15], some progress on hydrogen-fuelled aircraft has been made. For example, ZeroAvia is developing hydrogen-electric aircrafts, aiming for a 10-20 seat aircraft ready for service by 2025[16]. Similarly, Loganair is working with Cranfield Aerospace Solutions with the view to having the first operational hydrogen-electric Britten-Norman islander (10-person aircraft) flying by

[14] https://www.concawe.eu/wp-content/uploads/Rpt_22-17.pdf Table 75 vs 103
[15] https://www.theccc.org.uk/wp-content/uploads/2020/12/Sector-summary-Aviation.pdf
[16] Home - ZeroAvia

2027[17]. At a more global scale, Airbus is working with easyJet, London Gatwick and Air Products to expand hydrogen capability and infrastructure in the UK, to support Airbus' aim to get a hydrogen-powered aircraft in the sky by 2035[18].

That being said, hydrogen in aviation is a very high risk market and there are several key headwinds being faced, including:

- Low technology readiness level of the technologies that would be needed to make hydrogen in aviation widespread.
- Significant safety and regulatory challenges associated with transporting hydrogen in an aircraft, issues the Civil Aviation Authority's Hydrogen Challenge is seeking to address[19].
- Competition from battery electric aircraft, hybrid battery electric aircraft and drop-in liquid fuels (often collectively referred to as "Sustainable Aviation Fuel", or SAF). The possible space for hydrogen aircraft is squeezed from both above (by SAF) and below (by battery electric aircraft), and from all directions by hybrid electric aircraft.

Currently the only deployable option for decarbonising jet aircraft is via SAF, which have been successfully demonstrated on a small scale[20]. For short routes with propellor aircraft, battery electric aircraft have been successfully demonstrated on a small scale[21]. Both SAF and battery electric aircraft have identifiable drivers of uptake. In the case of SAF, UK regulation will require a 10% blend of SAF in airline fuel in 2030[22], while battery electric aircraft benefit from significant operational cost savings over combustion engines, as aptly demonstrated by battery electric ground vehicles. By contrast, hydrogen has no such regulatory or economic driver of uptake and faces uniquely challenging safety and regulatory challenges hindering uptake. These are outlined in the subsequent paragraph.

Assuming no commercialisation of disruptive battery technologies in aviation before 2050, literature suggests a conservative all-electric range for battery electric aircraft of 400 km in 2030 and 600 km in 2035, including operating reserve range[23]. Achieving significant range advantage over battery electric aircraft requires the use of liquid rather than gaseous hydrogen, bringing additional challenges. Some of the challenges associated with hydrogen aircraft deployment are briefly summarised below.

- **Safety and certification challenges**: the relatively low volumetric energy density of hydrogen compared to kerosene means that liquid hydrogen would need to be stored in the fuselage of the aircraft. Even ground storage of liquid hydrogen is limited to modest quantities owing to explosion risks. Storage of liquid hydrogen inside the fuselage of the aircraft would require a solution to prevent the usual boil-off of liquid hydrogen causing an explosive mixture of hydrogen and air to be formed inside the aircraft fuselage while also embrittling the airframe if not contained. Overcoming this safety limitation requires design, demonstration and certification of a completely new type of aircraft. The Climate Change

[17] Loganair and Cranfield Aerospace Solutions Set Sights on Debuting World's First Operational Hydrogen-Electric Britten-Norman Islander in Kirkwall by 2027 - Cranfield Aerospace Solutions
[18] Airbus welcomes easyJet and London Gatwick to global hydrogen hub
[19] https://www.caa.co.uk/our-work/innovation/hydrogen-challenge/
[20] https://corporate.virginatlantic.com/gb/en/media/press-releases/worlds-first-sustainable-aviation-fuel-flight.html
[21] https://www.aerospacetestinginternational.com/news/electric-hybrid/eviations-alice-all-electric-aircraft-completes-first-test-flight.html and https://www.rolls-royce.com/innovation/accel.aspx
[22] https://assets.publishing.service.gov.uk/media/6424782560a35e00120cb13f/pathway-to-net-zero-aviation-developing-the-uk-sustainable-aviation-fuel-mandate.pdf
[23] https://www3.weforum.org/docs/WEF_Target_True_Zero_Aviation_ROUND_2022.pdf

Committee highlights that a demonstration of this form would take "several decades"[24], particularly for long-haul aircraft, which would need to be completely redesigned from scratch to run on liquid hydrogen. An additional point in this regard is the provision of a failsafe mechanism for hydrogen aircraft. Regulation dictates that, if a fuel pump fails, the fuel must still flow to the engines – this is ensured by gravity in current aircraft, with kerosene flowing from the wings to the engines underneath. A new failsafe mechanism is just one example of a technology that would need to be designed, tested and then passed through the lengthy certification process before being introduced into production aircraft.

- **Lack of a business case**: the business case for hydrogen in aviation would depend on a long-term fuel cost advantage over SAF such that switching to hydrogen could improve airline profitability, net of the additional infrastructure and aircraft costs associated with a disruptive fuel change. It is not immediately obvious that this is achievable in practice for two reasons.
  - First, the economic impact of higher fuel costs on airlines is limited because of the modest contribution of fuel costs to total ticket prices and low fuel price elasticity of aviation demand[25].
  - Second, hydrogen aircraft would bring their own costs that would need to be covered by the fuel cost advantage: new infrastructure, and, in the case of combustion aircraft, higher maintenance and leasing costs[26].
- **Technology lock-in**: as mentioned earlier, regulation will mandate an increasing use of SAF in aircraft. The drop-in nature of this fuel means that its deployment is not hindered by the multi-decade asset turnover times in aviation. Even if hydrogen jet aircraft do become available in the 2040s, the motivation for airlines to adopt them, when they are already significantly decarbonised by SAF is unclear.

Achieving a fuel cost advantage over SAF is more likely to be possible with fuel cell electric aircraft than hydrogen jet engine aircraft, owing to the higher efficiency of the fuel cell option. Hence, a business case of hydrogen aircraft is most likely to exist for liquid hydrogen fuel cell aircraft operating on long-distance turboprop routes over 600 km. The long distance is needed to remove battery electric aircraft from the competition (under conservative battery assumptions), while the operation on turboprop routes means aircraft speeds will be like those realistic for fuel cell electric aircraft, preventing an additional cost penalty from slower travel.

4.2.2 DEMAND MODELLING

ERM analysis of UK Civil Aviation Authority airport departure data reveals[27] that roughly 84% of passenger-km from UK domestic scheduled and chartered passenger aircraft results from flights under 600 km in length that are likely to be able to convert to battery electric by 2050

[24] https://www.theccc.org.uk/wp-content/uploads/2020/12/Sector-summary-Aviation.pdf
[25] For example, Ryanair's income statement from 2022 (https://investor.ryanair.com/wp-content/uploads/2023/07/Ryanair-2023-Annual-Report.pdf) reveals that fuel represented around one-third of the firm's total costs. Therefore, doubling fuel costs would only lead to a 33% rise in ticket prices. Recent work by the IEA (https://www.iea.org/reports/the-role-of-e-fuels-in-decarbonising-transport) highlights how the consumer demand for aviation is relatively price-inelastic, suggesting that such price increases could be passed onto airline customers.
[26] A hydrogen jet aircraft would have all the maintenance and capital costs associated with a traditional kerosene jet aircraft, combined with additional costs from novel storage tanks capable of safely storing a highly explosive gas in liquid form close to absolute zero.
[27] https://www.caa.co.uk/data-and-analysis/uk-aviation-market/airports/uk-airport-data/uk-airport-data-2023/january-2023/

as discussed earlier. These domestic flights are currently performed a mixture of turboprop propellor aircraft and jet aircraft. The distance of up to 600 km leaves these flights with two options – switching to electric aircraft, or use of SAF. International flights from the UK are performed almost entirely by jet aircraft, which, for the reasons discussed earlier, will continue to decarbonise using SAF, with no role for direct hydrogen use up to 2050 owing to technological, financial, safety and regulatory challenges. Biofuel supplies will be insufficient to meet most expected future SAF demands. However, SAF can be manufactured primarily from hydrogen using a Power-to-Liquid pathway, and this method of production and supply is likely to be far easier to scale up than any direct use of hydrogen on aircraft.

This leaves domestic flights over 600 km as a potential niche for hydrogen fuel cell aircraft to occupy. Routes primarily consist of those between London and Aberdeen or Inverness. A few inter-regional routes, such as those operated by Loganair from Southampton and Exeter may be in range, but as demonstrated by the commercial failure of Flybe[28] are commercial vulnerable to relatively small changes in costs. In practice, it is more likely (as assumed by DfT)[29] that these routes will be performed by hybrid aircraft, which will be able to make use of existing infrastructure and fuel availability for both battery electric and SAF powered aircraft.

Domestic flights over 600 km account for around 16% of UK domestic aviation fuel use (ERM analysis based on CAA data as mentioned earlier), and domestic aviation accounts for around 3.8% of UK aviation fuel use[29]. Combining these figures results in hydrogen displacing around 0.6% of kerosene demand in UK aviation in 2050, with a resulting UK-wide hydrogen demand of about 50 tonnes per day. There are five routes with significant passenger flows that this could correspond to, connecting Gatwick and Heathrow to Glasgow, Aberdeen, and Inverness. If the aircraft were powered by liquid hydrogen, it is unlikely that these airports would receive hydrogen using the existing gas grid (with associated need for on-site liquefaction, purification and verification as aircraft fuel cell-grade), since Heathrow and Gatwick could be supplied by a single centralised electrolyser and liquefaction plant (with short-distance trucking of the liquid hydrogen to the two airports), with a similar scenario for the three Scottish airports mentioned.

4.3 COACHES

4.3.1 CONTEXT

Zero emission coach technology, policy and business planning lag a decade behind bus. The British battery electric coach fleet numbers less than a hundred vehicles, while production hydrogen coach models are only now becoming available to trial and order[30]. DfT's Transport Decarbonisation Plan[31] suggested a 2040 end date for the sale of non-zero emission coaches, but legislation is not imminent.

The largest contractors of scheduled intercity coach are actively planning coach decarbonisation, with both Flixbus and National Express pursuing hydrogen coach trials,

[28] https://en.wikipedia.org/wiki/Flybe_(1979%E2%80%932020)
[29] https://www.theccc.org.uk/wp-content/uploads/2020/12/Sector-summary-Aviation.pdf
[30] https://www.sustainable-bus.com/news/busworld-europe-brussels-2023/ and https://www.sustainable-bus.com/alternative-drive-coach/wrightbus-hydrogen-coach-2026-project/
[31] https://www.gov.uk/government/publications/transport-decarbonisation-plan

although increasingly talking about battery electric as a solution[32]. For the wider coach sector, this lack of clarity on future fuels has, according to industry body CPT's coach decarbonisation taskforce[33], "resulted in hesitancy, preventing the sector from moving forward".

Like many sectors faced with unclear decarbonisation pathways, expectations have started to shift towards the use of drop-in fuels, such as Hydrotreated Vegetable Oil, or even hydrogen as a combustion fuel. ERM analysis suggests HVO is structurally supply-constrained, with the aviation sector's demand for biofuel likely to price road operators out of the market before the end of this decade. Hydrogen as a combustion fuel is unlikely to be acceptable on local roads due its emissions of other harmful gases, and thus far DfT policy has pushed back against it.

While currently discussed as a single sector, in the context of decarbonisation, there are three broad categories of coach operation, each of which raises different decarbonisation issues:

- Private hire and group tours, at mid to long distance, and on a wide and changeable variety of routes. These duties can imply refuelling away from base, yet the location of that refuelling may vary from day to day, suggesting significant reliance on public or shared facilities.
- Scheduled long-distance intercity coach services, often intensively operated, typically over distances where one return trip exceeds likely battery capacity, but like buses, between the same places every day, meaning energy requirements are predictable.
- Local contract work that might use coach-bodied vehicles and might currently make use of a mixed fleet that also performs longer-range duties, but which alone raises similar issues, with similar solutions, to local bus decarbonisation.

4.3.2 TOURS AND GROUP HIRE

Perhaps more than any other road vehicle duty, tour/group hire coach operations would benefit from the operational flexibility and range granted by hydrogen.

Group hire and day trips naturally suit solely at-depot refuelling. Multi-day tours, in contrast, would be much more dependent on a network of public refuelling stations. Or potentially a much larger fuel tank than is currently found on hydrogen fuel cell buses – a requirement hydrogen coach manufacturers have already started to recognise. Tour/group hire markets are likely to be less price, and more time, sensitive than intercity coach markets. This means the higher operating cost of hydrogen fuel relative to battery electric may be outweighed by the operational flexibility of hydrogen.

Coach driving hour regulations are comparable to Heavy Goods Vehicles, which in practice means that the range of a coach is defined as 4.5 hours of driving, so long as the driver's rest break coincides with appropriate charging infrastructure. On longer trips, these stops are likely to occur at Motorway Service Areas (MSAs) because these offer refreshment facilities for passengers. High-power battery electric chargers are anticipated at all MSAs as part of DfT's Rapid Charging Fund[34], with similar facilities mandated in continental Europe[35]. As the use of

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[32] Largely Flixbus https://www.route-one.net/news/zero-emission-tech-mix-likely-in-future-of-coach-flixbus/ (for example https://www.route-one.net/news/flixbus-to-launch-first-zero-emission-coach-service-with-newport-transport/) and National Express https://www.route-one.net/news/data-and-investment-a-work-in-progress-for-national-express/

[33] https://www.cpt-uk.org/campaigns-reports/zero-emission-coach-taskforce/

[34] https://www.gov.uk/guidance/rapid-charging-fund

[35] https://ec.europa.eu/commission/presscorner/detail/en/IP_23_1867

battery electric vehicles grows, it is reasonable to expect major destinations start offering slower charging solutions for visiting coaches, much as they currently provide coach parking. This style of battery electric operation would require far more precise operational planning than is currently the case but would not be conceptually impossible, which means hydrogen is not the only potential solution.

This is important because except for a handful of larger providers, such as Skills and City Circle, tour and group hire coach operators tend to be small and local. Even with large fuel tanks that avoid the need to refuel away from home depot on most trips, these smaller operators would be unlikely to attain the required scale to refuel locally, as discussed in 4.3.4. So, while there may be a viable theoretical market for hydrogen coaches for tour and group work, supplying this market in a cost-effective manner may be challenging.

4.3.3 SCHEDULED INTERCITY COACH

Most scheduled long-distance coach services in Great Britain are contracted and operated on behalf of National Express, Stagecoach Megabus, or Flixbus, often with vehicle and driver provided by a local coach or bus operator. The commercial working life of coaches in this sub-sector is about 5 years, far shorter than the 15 years more typical of the wider bus and coach sector. This means that while all the major players have fleet decarbonisation targets for 2035 or 2040, current replacement cycles mean vehicle decarbonisation does not strictly need to commence until the 2030s.

The method used for local bus demand modelling (described in 4.5.3) was reused to analyse potential hydrogen demand for Flixbus, National Express and Stagecoach Megabus across Great Britain[36]. Long-distance coach has been modelled with battery energy use of 1.2 kWh/km, reflecting the significantly greater efficiencies Ember attain in their coach-like operations in central Scotland.

All scheduled coach mileage was modelled at 3.2 million kilometres per week. Only 13% of this was modelled to be manageable with a two-axle[37] battery electric vehicle in the 5-year period when Zero Emission vehicles would need to be introduced to meet operators' fleet decarbonisation targets. If the remainder were all converted to hydrogen, around 24 tonnes would be required daily across Great Britain.

For context, this upper limit of potential intercity coach demand is equivalent to just under 20% of all potential local bus demand for hydrogen across Great Britain (assuming all potential is realised, which as outlined in 4.5.5, is extremely unlikely). The presence of only three significant decision-makers, each ultimately able to specify vehicles and adjust operations, should make it possible to focus much of that hydrogen onto core operational hubs. However, such a strategy of operational evolution is equally valid for battery electric operation, as demonstrated by Ember, whose entire schedule logic appears to be built around the charging requirements of their battery electric coaches.

The long-distance, typically low-budget, leisure markets that characterise most intercity coach can be incentivised through fares to shift times of travel. It is thus not strictly necessary for

[36] Flixbus schedules were not included in DfT BODS so were processed from French government open datasets - https://transport.data.gouv.fr/datasets/flixbus-horaires-theoriques-du-reseau-europeen-1

[37] Coaches tend to be more weight-restricted than buses due their need to carry luggage in addition to passengers, while many scheduled coaches are already triaxle. This makes the use of modelling assumptions intended for local bus imperfect.

existing coach schedules to be mimicked with zero emission vehicles in the way we reasonably assume it is for local buses. Even routes with challenging single-trip battery electric compatibility, such as London-Glasgow, may ultimately resolve that the slower journey time implied by a mid-journey stop to opportunity charge or change of vehicle is more commercially attractive than passing on the increased cost of hydrogen fuel to passengers.

Even more so than Interurban buses, the combination of intense duties, long range, and dispersed networks, makes a strong technical case for hydrogen-powered coaches for scheduled intercity services. However, the practicalities of supplying hydrogen to such a niche and geographically distributed market, combined with the price (vs time) sensitivity of most intercity coach passengers, may favour a technically sub-optimal battery electric solution.

4.3.4 LOCAL CONTRACT DUTIES

Local contract duties tend to be predictable from day-to-day, in relative proximity to the operator's base, and generally require less energy than many bus duties. Technically, Battery Electric Buses (BEBs) are already able to offer a decarbonisation solution for many of these duties, a conclusion implicit in CPT's estimate[38] that 50% of all coach operators' services "could be delivered on current technology".

Battery electrification raises a raft of practical and commercial difficulties for coach operators, especially where their depots are leased and thus challenging to electrify, or where they cannot financially manage the uncertainties introduced by battery depreciation. In this environment, hydrogen's operational flexibility and functional similarity to diesel may appeal to operators seeking to maintain *business as normal*.

However, the increased operating costs of hydrogen (akin to those discussed in 4.5.3) would not be sustainable in a competitive contractual market open to BEB operators. Regardless, the relatively small size of local coach fleets (only a handful exceed a hundred vehicles, with 10 or 20 more typical) would make dedicated fuelling facilities inefficient. Given the remote location of many coach operators, widespread hydrogen uptake in the Heavy Goods Vehicle sector would be needed for coach operators to efficiently share fuelling with other modes.

4.4 HEAVY GOODS VEHICLES

4.4.1 APPROACH

The table below summarises our approach to modelling potential hydrogen demand for Heavy Goods Vehicles (HGVs), details of which are described in subsequent sections.

TABLE 4: APPROACH TO HGVS

Action	Comment
Model energy requirements of truck duty cycles	Considering mileages, trips, and payloads
Identify duties challenging for battery electric	Many trucks are certain to convert to battery
Analyse Total Cost of Ownership (TCO)	Relative costs of hydrogen and battery
Assign likely year of decarbonisation	Using expected fleet-wide uptake curve

[38] https://www.cpt-uk.org/media/ujknzryr/zect-coach-route-to-destination-zero-report-final.pdf

Action	Comment
Assign to relevant truck depot locations	Based on sites modelled with articulated truck fleets
Assess likelihood of hydrogen adoption	Considers hydrogen market scaling issues

4.4.2 CONTEXT

Progress is being made on hydrogen HGVs, with several OEMs planning to series-produce fuel cell electric heavy-duty trucks (e.g. Iveco, Volvo Group and Mercedes-Benz). There are also planned demonstrations of hydrogen HGVs in the UK, many of which are being supported by funding from Government. This includes the Zero Emission HGV and Infrastructure Demonstrator programme which is supporting the HyHaul project, which aims to deploy 30 hydrogen HGVs in the South West and Wales, and the Zero Emission North Freight project[39], which aims to deploy 16 hydrogen HGVs in the North of England in the mid 2020s. In addition, one of the projects funded under the Tees Valley Hydrogen Transport Hub scheme, the Tees Valley Hydrogen Vehicle Ecosystem project, will support 25 fuel cell electric HGVs[40].

Despite this, battery electric vehicles offer a feasible option for many Heavy Goods Vehicles (HGVs), including international long haul. More detail on this is provided in ERM's thought leadership piece in this area: https://www.erm.com/insights/why-electrification-of-great-britains-truck-fleet-can-happen-faster-than-many-expect/. In particular:

- **Range and recharging speed of 2024 battery electric HGV models are sufficient even for long haul HGV operations**: Sufficient range for 4.5 hours of motorway driving at full load, followed by a complete recharge using 1 MW charging (an upcoming standard already being piloted at several sites in Europe) during the 45-minute mandatory driver rest break prior to the second half of the shift with 4.5 hours of motorway driving. In fact, the ability to drive 4.5 hours on a motorway in 45 minutes of recharging is more than is needed for most UK HGV operations – 4.5 hours of motorway driving is very rare even for 44 tonne vehicles. This is because HGVs stop to pick up and drop off goods, reducing distances travelled and increasing available downtime for charging (e.g., charging the tractor unit nearby while the trailer is unloaded). It is for this reason that for most HGV operations – even 44 tonnes – slower charging speeds (c. 350 kW) will be sufficient. ERM analysis of data provided by Department for Transport (DfT) from the Continuing Survey of Road Goods Transport reveals that around 98% of 44t HGV trips[41] are less than 378 km[42] in length and – accounting for lower energy use (and hence increased vehicle range) on partly loaded trips – around 99% of UK 44t HGV trips can be performed on a single charge by a vehicle capable of driving for 4.5 hours at full load.

[39] ZEN Freight project re-groups after bp withdraws from DfT-funded ZEHID trials | Article | Freight Carbon Zero
[40] Tees Valley hydrogen transport hub: successful bidders - GOV.UK (www.gov.uk)
[41] A trip refers one pick up – drive – drop off cycle. A driver shift will normally comprise multiple trips with downtime and charging opportunities between each trip.
[42] 4.5 hours at UK average HGV motorway driving speed - https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/953335/evaluation-of-the-national-hgv-speed-limit-increase-in-england-and-wales-year-2-interim-report-document.pdf

- **Payload**: Payload loss for long haul battery electric HGVs is only around 2 tonnes, as reported by OEMs (original equipment manufacturers)[43]. Most HGV operations are in fact volume-limited not weight-limited, and so the battery weight has no impact of the payload for many trips (see ERM's thought leadership piece referenced earlier for further details). For those 44 tonne HGV operations that do operate at maximum payload, the small payload loss from switching to battery electric incurs a small cost penalty, which is included in the total cost of ownership modelling presented later.
- **Total Cost of Ownership**: Even for most long-haul operations, the high fuel costs of hydrogen HGVs mean that they do not get close to competing with battery electric HGVs on TCO even under the most optimistic assumptions for hydrogen. The total cost of ownership is explored later.

4.4.3 DEMAND MODELLING

Based on ERM modelling, using the DfT's Continuing Survey of Road Goods Transport[44] data on the duty cycle (including mileages, trip lengths and payloads) of a representative sample of several thousand HGVs, the annual energy use (supplied to the vehicle battery) if all GB HGVs were electrified is estimated at circa 22 TWh.

UK HGVs can be divided into 4 main groups, these are:

1. Rigid HGVs that can complete their operations with only depot charging – circa 47% of vehicles and 18% of energy use.
2. Rigid HGVs that will need some public charging to complete their longest trips – 11% of vehicles and 13% of energy use.
3. Articulated HGVs that can complete their operations with only depot charging – 20% of vehicles and 18% of energy use.
4. Articulated HGVs requiring public charging – 22% of vehicles and 53% of energy use, of which almost all is from 44 tonne long distance articulated HGVs – 50% of HGV energy use.

Hydrogen demand from HGVs, will be dominated by the final group (4) since this is the group with the most long route, high payload operations where battery electric operation is more challenging. OEM model line-ups and announcements to date indicate an exclusive focus on battery electric for (1) – (3) and a primary focus on battery electric for (4) (for Scania and MAN, an exclusive focus on battery electric for (4)).

To ascertain the potential hydrogen demand, we therefore focus on case (4) – 44t long distance HGVs, which accounts for half of all HGV energy use. The graph below shows the Total Cost of Ownership (TCO) of battery (BEV) and fuel cell (FCEV) electric vehicles relative to diesel across all the circa 1,600 44 tonne long distance HGV use cases in the DfT CSRGT sample, including the cost of any payload loss and charging time loss for the BEV case. For the

[43] See for example the Daimler eActros 600, already in series production - https://www.daimlertruck.com/en/newsroom/pressrelease/mercedes-benz-trucks-celebrates-world-premiere-of-the-battery-electric-long-haul-truck-eactros-600-52428265
[44] https://www.gov.uk/government/statistics/continuing-survey-of-road-goods-transport-gb-respondents-section

hydrogen case we assume (very optimistically) that hydrogen prices fall to £7/kg at the pump by 2030[45].

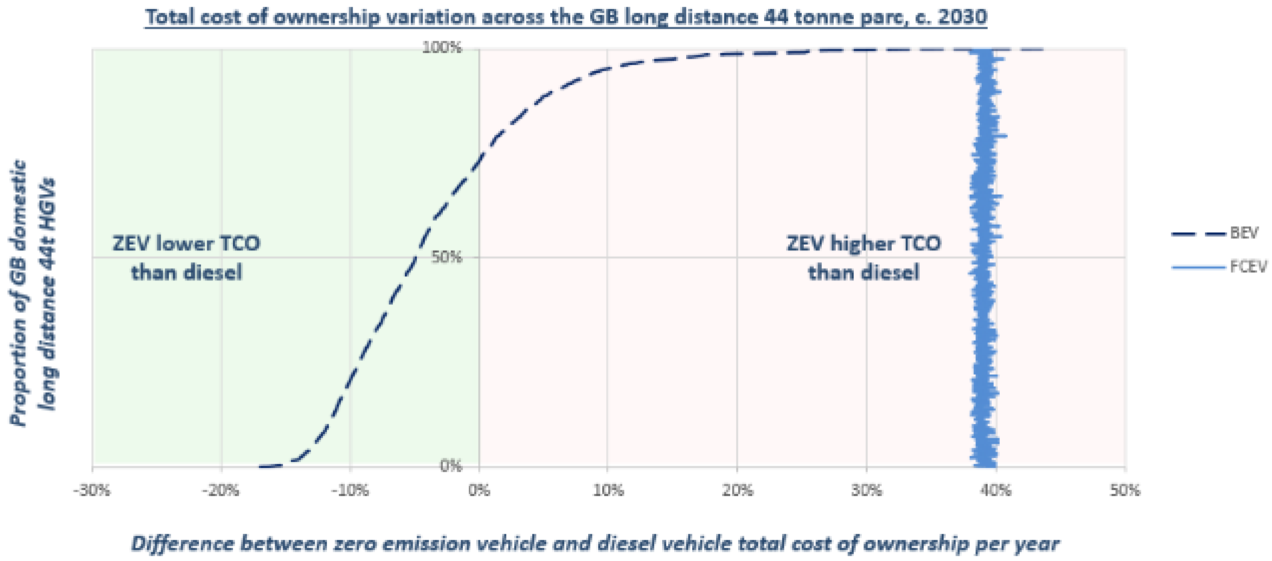

FIGURE 15: TOTAL COST OF OWNERSHIP VARIATION ACROSS THE GB LONG DISTANCE 44 TONNE TRUCK PARC (2030), UNDER OPTIMISTIC ASSUMPTIONS FOR HYDROGEN FCEV

95% of GB 44t long distance HGVs operate in use cases that are amenable to battery electric, i.e., will either be cheaper with BEV or within 10% of diesel TCO with BEV around 2030. The remaining 5% are more challenging for battery electric. Included in this remaining 5% are:

- 2-driver long distance use cases with 2 drivers in the vehicle at the same time (and hence no time to charge when drivers are swapped over), and
- Use cases that do infrequent very long trips.

This 5% represents the potential upper limit hydrogen demand from HGVs within Great Britain, as the remaining 95% would likely select BEV options instead. Figure 2 demonstrates that for this 5% of GB 44t long distance HGVs to be FCEV (the very top part of the graph), operators would need to be willing to pay a TCO premium of up to circa 30% for the flexibility offered by FCEV over BEV. Since these use cases do higher mileages than the average even for 44t long distance HGVs, they account for 7% of 44t long distance HGV energy use – which (based on the total figure of 22 TWh/year if all HGVs were electrified) amounts to 125 tonnes of hydrogen per day, across GB, if all this group went to hydrogen.

For international HGVs, we use ETISplus[46] mileage data to estimate a total energy use if all were electrified to be 2.1 TWh/year. Assuming 10% of international HGV energy use arises from hydrogen HGVs (a higher proportion than domestic articulated HGVs owing to the longer distances, with the remainder switching to battery electric), this adds 31 tonnes per day of

[45] As a base example, consider that a future grid-connected electrolyser project using 50 kWh of electricity per kg of hydrogen. At current electricity prices (about 12p/kWh) this would price hydrogen at about £6/kg, before any capital, distribution or dispensing costs. While direct connection to renewable generation might halve the effective cost of electricity, such a scenario would not be without further capital and distribution costs. Any estimate of future hydrogen prices masks a wide range of assumptions about the future cost-effectiveness of currently immature technology. Since the main determinant tends to be electricity price, much of the price variation applies equally to battery electric alternatives, and thus a best-case price for hydrogen does not necessarily make it significantly more competitive among transport operators.

[46] https://data.mendeley.com/datasets/py2zkrb65h/1

additional hydrogen demand within Great Britain, giving a 2050 upper bound of 156 tonnes of hydrogen per day, across GB.

The hydrogen demand trajectory from now to 2050 is estimated by assuming that FCEV sales reach their maximum value (up to 5% of 44t long distance HGVs) in 2040 and then remain constant thereafter. The ramp up of this sales percentage starts from zero in 2028 (the approximate year at which Volvo and Daimler have hinted at for starting series production of their hydrogen trucks).

4.4.4 ASSIGNMENT

Based on an uptake curve for hydrogen fuel cell HGVs[47], the total Great Britain HGV hydrogen demand modelled above was assigned to the 5-year period in which it might materialise. The numbers are shown below - for example, 27% of the HGV hydrogen demand is expected to come into existence between 2030 and 2035.

- 2025-30: 3%
- 2030-35: 27%
- 2035-40: 38%
- 2040-45: 27%
- 2045-50: 3%

This distribution of national demand is used because only limited assessments can be made of when each fleet might decarbonise without knowledge of which customers or sector that fleet serves. This approach can result in very small potential demands in any one period, especially in the first and last periods, which are accurate on aggregate only. For example, smaller fleets are likely to adopt hydrogen in just one period because of the need to establish dedicated fuelling facilities and institute new engineering practices.

The distribution of demand was then applied to local truck depots modelled with at least 10 articulated trucks, in proportion to the number of artic trucks modelled at each depot. Location assignment intentionally excluded the "long tail" of very small truck fleets, presuming such fleets would lack the technical economies of scale to support hydrogen. The ten-vehicle minimum reflects initial hydrogen trials in the bus sector with fleets of typically 10-20 vehicles, a scale at which operators have still struggled to manage specialist engineering support.

Depot locations were derived from Driver and Vehicle Standards Agency licence addresses[48], specifically geocoded postcodes. In industrial areas, where depots tend to be located, postcodes typically approximate coordinates to within a few hundred metres of a depot's actual location. Eventual clustering further averages and obfuscates precise location, which ensures no individually identifiable data is released in the final output.

Public Service Vehicle (bus and coach) operators were excluded by licence criteria. The inclusion of trailers on a licence was used as a proxy for the presence of articulated, rather than rigid, trucks. Legally there is no distinction between a licence for operating an artic and a rigid truck. The number of vehicles listed on the licence was then further used as a proxy for the proportion of the national artic fleet[49] present at each depot. Overall, truck operators only

[47] Factoring in the TCO modelling discussed earlier.
[48] https://www.vehicle-operator-licensing.service.gov.uk/search/find-lorry-bus-operators/
[49] https://www.gov.uk/government/statistical-data-sets/vehicle-licensing-statistics-data-tables

use two thirds of the fleet they are collectively licensed for, the remainder retained for organic growth or ease of vehicle replacement.

Depot-specific demands were then clustered as described in 4.1.2.

4.4.5 RISKS

A 30% chance of decarbonisation through hydrogen has been assumed for both domestic and international duty cycles, as rationalised below.

The niche in the market identified for hydrogen HGVs above focuses on long-haul vehicles travelling across Great Britain and Europe. These use cases struggle to match the concentrated demand for vehicles and infrastructure both temporally and geographically needed to make an easy investment case as set out below:

- **Limited HGV sales**: For vehicle production, ERM analysis covering all of Europe (including the UK) indicates that the niche use cases for hydrogen in trucking only correspond to sales of around 1,000 to 2,000 vehicles sales per year (maximum), which is at least one order of magnitude below the tens of thousands of vehicle sales per year needed to bring down the capital cost of the vehicles to the prices assumed in the TCO modelling[50].
- **Scattered refuelling demand**: To support the business case for stations, station operators are looking for scale of demand in a local area, at a specific point in time, supported by good hydrogen distribution routes. From a station point of view the minimum efficient scale is around 1 tonne per day operating at high utilisation. This can increase to tens of tonnes per day for pipeline fed stations as the effective scale required for de-blending or purification is higher than for the station itself. Gaining this scale is impacted by differences in refuelling technology preferences between OEMs: Daimler prefer liquid refuelling, while Volvo prefer 700 bar gaseous, which results in a double up of station requirements. Building station scale also requires local demand to act as an anchor load for station investment, our analysis show that only a quarter of all potential HGV demand would sit within a cluster of sufficient size to warrant a station and much of this demand will be spread temporally impacting the opportunity to build well utilised stations. Overall, delivering station scale is seen to be a challenge because the 150t/day demand will build up over 15 years, be split between gaseous and liquid hydrogen, with possibly different distribution routes and be distributed geographically.

Looking more broadly at Europe we see that EU regulation[51] mandates a certain minimum amount of infrastructure (HRS every 200 km of TEN-T and at urban nodes). However, an HRS every 200 km of TEN-T only corresponds to a total of 475 HRS across the whole of Europe. These stations must, by regulation, have a capacity of 1 tonne per day, which can be dropped to 0.5 tonnes per day if demand does not materialise. Hence, the implied demand for the whole of Europe is between 240 and 475 tonnes per day. This suggests to will be theoretically possible for a hydrogen truck to travel around Europe but does not imply an expectation of significant demand. It should be noted that this regulation does not mandate demand for hydrogen and utilisation of infrastructure, it does not mandate OEMs to sell FCEVs, nor

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50 https://h2accelerate.eu/wp-content/uploads/2022/09/H2A-Truck-TCO-and-Policy-Support-Analysis-VFinal.pdf

51 https://ec.europa.eu/commission/presscorner/detail/en/IP_23_1867

operators to buy FCEVs. Hence, there is a significant chance that these stations will remain at low utilisation.

4.5 LOCAL BUSES

4.5.1 APPROACH

The table below summarises our approach to modelling potential hydrogen demand from local buses, details of which are described in subsequent sections.

TABLE 5: APPROACH TO BUSES

Action	Comment
Process schedules into route network graph	Individual trips summarised as repeated patterns
Calculate route distance from stop locations	Factored up for indirectness of roads
Assign operational archetype to route	Considers frequency, distance, and demography
Estimate bus route energy demand	Uses worse case energy consumption, derived from tolerance of current Battery Electric Bus (BEB) operators
Estimate peak vehicle requirement	Also assesses slack buses in off-peak
Assign route to home bus depot	Via real-time data or proximity to termini
Identify challenging routes for BEBs	In period prior to operator's decarbonisation target
Assess likelihood of hydrogen adoption	Compares hydrogen to BEB-based solutions

4.5.2 CONTEXT

Local bus refers to passenger vehicles operated on registered local bus services. In England, local bus services are almost always operated by bus-bodied vehicles. Local bus excludes non-public contracted services and demand responsive/community minibus. Home-to-school services in Great Britain operate as a mix of public and non-public – they are included here only where public[52]. Scheduled services with route length of greater than 100 kilometres are considered "coach". Coaches are discussed in section 4.3.

The decarbonisation of bus vehicles is not yet mandated in law. However most large bus operators, and many of the local government agencies they partner with, have announced fleet (or equivalent) decarbonisation targets between 2030 and 2040. Of all the transport modes modelled here, local bus has the clearest set of decarbonisation pathways, and will tend to be the earliest of all the heavy-duty transport modes to decarbonise. This early decarbonisation trajectory reflects a mix of factors - strong clean air and net zero policy objectives within many cities, consistency of daily bus vehicle duty cycles and vehicle operating locations, relatively mature decarbonisation technology, and reasonable Total Cost of Ownership business cases.

[52] In practice dedicated school services are associated with short vehicle duty cycles, unsuitable for hydrogen

There are already multiple hydrogen fuel cell bus fleets in commercial passenger operation in Great Britain, with about 20 urban buses deployed in each of Aberdeen, London, Merseyside and the West Midlands. Go Ahead group's continued expansion of their Crawley fleet is perhaps the most significant, showing the operator's willingness to expand their hydrogen fleet beyond the first batch of the vehicles, and highlighting the role for hydrogen solutions to address those hard-to-decarbonise frequent interurban routes primarily operated from their Crawley depot.

Battery Electric Bus (BEB) technology is mature, with the best manufacturers and operators already attaining the desired 90% vehicle availability[53]. On average diesel fuel accounts for 13% of operating cost[54], with electricity able to reduce fuel cost by up to 70%[55]. Depreciation and leasing costs are historically 10% or less of operating cost. A BEB's fuel cost savings can thus offset up to a doubling of the vehicle's capital cost. Battery technology changes several investment assumptions, such as the working life of a BEB being longer than a diesel bus while requiring a mid-life battery replacement. But in broad terms, the Total Cost of Ownership of a BEB is already comparable, and only likely to improve over the next decade as battery prices continue to fall and economies of scale emerge in electric vehicle manufacturing[56].

There will be challenges transitioning from diesel to BEB, not least depot electrification and financial risk, but long-term the main limitation on BEB deployment is expected to be battery energy density: Prevailing battery chemistry means stored energy capacity is constrained by maximum legal vehicle weight. While future improvements in battery technology will gradually ease this constraint, a significant proportion of two-axle buses will continue to require more energy each day than they can carry from a single daily charge.

In some cases, routes already require extra vehicles only at peak times. This can allow operators to swap vehicles in and out of service off-peak, potentially with vehicles returning to depot for charging during the day. This can enable BEB operation without requiring extra vehicles. Where this is not possible all battery electrification options add cost, for example:

- Opportunity charging or similarly expensive fixed-location infrastructure, potentially including induction charging and trolleybus-like "in motion" charging.
- Extra vehicles to create the operational flexibility described above, which raises an operator's fixed costs.
- Tri-axle buses with larger and thus more expensive batteries, and potentially extra depot space.

It is on these bus routes that hydrogen's higher fuel cost can potentially be offset by the operational flexibility of being able to fuel a bus quickly for an entire day's duty, and thus avoid any of the cost or operational inconvenience associated with the battery electrification options listed above.

Zero Emission bus fuel cost assessment is complicated by a subsidy regime which, in England outside London, offers[57] 22 pence per kilometre. A bus using around 1.55 kWh of electricity

[53] ERM analysis of British real-time bus data.
[54] https://www.cpt-uk.org/media/ad4fjkwt/cpt-cost-monitor-06-2023-public.pdf
[55] https://assets.publishing.service.gov.uk/media/646f304c24315700136f4228/lebs-monitoring-report.pdf As discussed subsequently, subsidy regimes may reduce the operator's cost to almost nothing.
[56] Bloomberg NEF projections suggest a halving in price by 2035.
[57] https://www.gov.uk/government/publications/bus-service-operators-grant-guidance-for-commercial-transport-operators/bus-service-operators-grant-guidance-for-commercial-transport-operators Only in-service mileage is subsidised. This dead mileage (to and from depot) represents about 5% of total mileage for larger group operators but can be far higher for the smallest groups and independents.

per kilometre at a wholesale price of under 14 pence per kWh is effectively costing its operator nothing for fuel. In contrast hydrogen at £7 per kilogram and 0.06 kg/km costs 42 pence per kilometre, of which the operator therefore pays 20 pence.

The typical daily length of a local bus duty with hydrogen potential has been modelled using the method described below at just over 300 kilometres. Applying the assumptions above, hydrogen would cost about £60 more per bus per day than battery electric. This extra cost is in the order of 20% of revenue one might expect to earn with that bus, an increase only a minority of routes are likely to be able to sustain commercially.

As discussed in 4.5.5, BEB solutions to these challenging routes that used fixed infrastructure best suit intense or geographically focused operations, which many interurban and rural bus routes are not. Future demand for hydrogen buses could transpire to be primarily determined by the strength of political sensitivity around rural public transport provision.

4.5.3 DEMAND MODELLING

Bus duties do not change from day to day, so a vehicle's energy requirements are be defined by the duty on toughest day. This day is typically a school term-time weekday in extreme weather, when services are most intensely operated and when the energy required to heat or cool the passenger cabin is greatest.

Energy and vehicle requirements were modelled by bus route. The main source for bus routes was the Department for Transport's Bus Open Data Service (BODS) schedule dataset[58] for a sample week in term-time during May 2023.

Individual vehicle trip schedules were parsed into a network graph – a simplified map of bus services linking locations together. This graph consisted of "route variations", each defined as a unique sequence of bus stops in the order they are served by the bus. Each bus stop was located geographically. The number of scheduled vehicle trips for each route variation, and the average duration of those trips, were assigned to the network graph by hour of day, for weekdays, Saturdays, and Sundays.

Distances between bus stops were calculated using Haversine (direct line) distances, and then factored up by 117% to account for the indirectness of roads. This 117% value was derived from analysis of a sample of 5,400 routes where precise road routes were available in BODS. The annualised total vehicle mileage modelled equalled 97% of that recorded in national statistics for 2022, with no significant regional variations.

Bus stops were cross-referenced to their Rural-Urban classification[59], expressed as "urbanity", where the highest urban tier is 100% and the lowest rural tier 0%, with intermediate tiers distributed evenly between. Mileage between each stop was allocated an urbanity based on that of each stop pair, allowing the urbanity of each bus route to be summarised.

As shown in Table 6, the total weekly vehicle trips (one trip per direction), urbanity and route length were used to define route archetypes. These archetypes determine only the likelihood of demand emerging, not the hydrogen demand itself. Routes over 100 kilometres are considered as coach (discussed in section 4.3).

[58] https://www.bus-data.dft.gov.uk/

[59] https://www.gov.uk/government/collections/rural-urban-classification

TABLE 6: LOCAL BUS ROUTE ARCHETYPE DEFINITIONS

Archetype	Description	Weekly vehicle trips	Mostly urban or rural	Route length (km)
City	Core high-frequency urban	>= 600	Urban	< 40
Interurban	To regional centre from outside that centre	>= 100	Rural	20-100
		Any	Urban	40-100
Rural	Local rural or small town	Any	Rural	< 20
		< 100	Rural	20-100
Suburban	Secondary urban - lower frequency	< 600	Urban	< 40

The maximum energy required to operate each trip is calculated from distance only. In practice gradients have an impact of less than 10% in almost all cases, because buses are assumed to regenerate most of the extra energy lost going uphill when they eventually return downhill[60].

Hydrogen use by the current generation of (Wright Bus) vehicles has been derived from the Joint Initiative for hydrogen Vehicles across Europe (JIVE) project analysis[61] at 0.06 kilograms per kilometre, which operators have found to be reasonably consistent in all conditions.

BEB energy usage is typically less consistent and less likely to reflect test specifications[62] than hydrogen models in all operating conditions. DfT monitoring of early BEB projects[63] suggests typical consumption of 1-1.5 kWh/km including heating. While this analysis is robust, its sample size is very small and geographically selective, tends to reflect the oldest generation of battery management technology, and does not necessarily reflect how much battery capacity operational risk bus operators are prepared to take in practice.

Instead, an analysis was conducted of currently BEB-operated routes: A sample of real-time bus data[64] was used to identify the just over a hundred existing British bus routes where at least 90% of trips were BEB operated (indicative of a mature BEB operation) and where at least 1000 kilometres was operated each week (indicative of a regularly operated route). 70% of the mileage in this sample was on City archetype routes, with 22% on Suburban routes, meaning any assessment based on current operations was inevitably skewed to urban areas. The model was then calibrated to maximise the proportion of BEB-operated routes modelled as manageable to operate with BEBs. Manageable means both operated without needing to add

[60] The most extreme case in the whole of Great Britain, Aviemore-Cairngorm, has been modelled as losing only 15%, despite half the route averaging a gradient of 1 in 10.
[61] https://fuelcellbuses.eu/
[62] https://www.zemo.org.uk/work-with-us/buses-coaches/low-emission-buses/certificates-hub.htm In test conditions, BEBs can attain up to double the range assumed by our modelling method, for example, the latest Alexander Dennis Enviro400EV is reported to attain 0.67 kWh/km - https://www.sustainable-bus.com/electric-bus/adl-average-energy-consumption-of-just-0-67-kw-km-for-the-enviro400ev/ - although when exposed to extreme weather conditions performance can halve, as indicated by Yutong's testing https://www.sustainable-bus.com/electric-bus/yutong-testing-norway-cold-climate-technologies/
[63] https://assets.publishing.service.gov.uk/media/646f304c24315700136f4228/lebs-monitoring-report.pdf
[64] Gathered from https://bustimes.org/api/

any additional vehicles to existing route requirements and operated without under-utilising slack in the existing peak vehicle requirement.

From this, it was concluded that current BEB operations best fit an assumption of 1.55 kWh/km with up to 80% of battery capacity in use. Both single and double deck routes were analysed separately but both fitted the same pattern, possibly because while double deck vehicles logically require more energy, especially heating, they are also more likely to operate on routes with low average speed.

Advances in battery technology are expected to mean energy density rises rapidly from about 0.15 kWh/kg in 2020 to 0.20 kWh/kg in 2025, then more slowly to reach 0.25 kWh/kg by 2040. Fundamentally new technology, such as solid-state batteries, could change this assumption. Two-axle BEBs are limited in weight and thus limited in battery capacity, a limit that declines only gradually with improvements in battery energy density. While three-axle BEBs exist, both as articulated and double-deck models, neither is currently sold in Great Britain, and as discussed in 4.5.5, will not suit many British local roads.

For each route, the total round-trip time was calculated in each hour and thus the vehicle requirement in that hour to deliver the service. The route's busiest hour defined the Peak Vehicle Requirement. From this the operating hours, mileage, and energy of each vehicle required to operate the route was calculated, which in turn allowed any slack in vehicle requirement across each day to be identified.

No adjustment is made for inter-working of the same vehicle between different numbered bus routes. This cannot be identified from passenger schedule data. On more frequent routes inter-working is an operational optimisation, unlikely to fundamentally change any analysis of BEB compatibility. On rural routes ignoring interworking is more likely to over-estimate the vehicle requirement of any one route. In practice this error tends to affect occasional routes, which tend not to operate full days, and thus tend to imply low-to-mid duty intensities unlikely to suit hydrogen.

Each vehicle is assumed to travel into service to and from a home depot. This "dead mileage" is assumed 6% of a single in-service route duty, derived from analysis of the average distance between depot and nearest route termini, using data detailed in 4.5.4. This average is dominated by large and mid-size bus operating groups. In practice dead mileage tends to be far higher for small group and independent operators – using the same analysis method, over 15%. This could be one of the factors that makes BEB adoption fundamentally harder for smaller operators.

Bus routes were considered to have hydrogen potential where a BEB of maximum expected battery capacity (analysed for each year period) would require charging at least once during the day, time which there is no slack for in the existing route vehicle requirement once existing vehicle requirement, distance to depot, and downtime to charge were considered.

4.5.4 ASSIGNMENT

Bus operator depot location information was collected from a combination of Driver and Vehicle Standards Agency[65] licence addresses and enthusiast sources. Where possible, sample real-time data was used to relate routes to vehicles to dominant home bus depot. Where this

[65] https://www.vehicle-operator-licensing.service.gov.uk/search/find-lorry-bus-operators/

relationship could not be established, routes were assigned based on the nearest depot (used by the operator of the route) to either of the route's termini. Out-stations (overnight bus parking locations where no maintenance occurs) were ignored because these are generally not suitable for bus refuelling.

Each operator was assumed to leave their most challenging-to-decarbonise routes until the 5-year period immediately before their fleet decarbonisation target, or in the case of targets for only new zero emission vehicle purchases, 10 years later (based on a front-line working life of 15 years[66]). Individual corporate bus targets were used for the "big five" groups (the five largest groups, which collectively dominate the British bus market), secondary groups were assumed to adopt the bus industry body CPT's pledge[67] to buy only zero (or ultra-low) emission buses from 2025, while independents were assumed to react to legislation expected[68] to force the same behaviour after 2030. In practice some operators will move to decarbonise slightly sooner, for example to meet partnership commitments with local government, while some will struggle to meet their targets.

The hydrogen demand associated with all the local bus vehicle duties with hydrogen potential (from 4.5.3) was assigned to the duty's home depot solely in the 5-year period of decarbonisation determined above. Depot-specific demands were then clustered as described in 4.1.2.

4.5.5 RISKS

Hydrogen fuel cell buses will be one of several possible technologies that could be deployed to decarbonise bus routes which will be challenging to battery electrify. An assessment of the likely suitability of these options was used to evaluate the likelihood of hydrogen being selected for each operational archetype:

- **Opportunity charged BEBs**: Rapid charging infrastructure that does not require the bus to stop to charge longer than it would have otherwise stopped. Prevailing technology uses a pantograph, but induction or trolleybus-based technology also exists. Infrastructure is closely linked to battery strategy, as regular rapid charging implies faster battery degradation, but also potentially much smaller installed battery capacity. Reliance on fixed infrastructure limits operational flexibility. In broad terms, routes operated with ten or more dedicated buses, where all vehicles routinely return to the same place in the route, could be candidates for opportunity charging.
- **Extra BEBs with at-depot charging**: Use of home bus depot charging equipment during the day by extra BEBs, which are rotated in-and-out of services to charge, while overall maintaining route service levels. Extra buses both increase capital expenditure and fixed costs, such as insurance and depot space. Staff costs rise slightly due to the need to drive buses to and from depot. Where routes are less frequent, the extra buses may be inter-worked between routes. This approach relies on depots being reasonably close to route termini, to minimise time lost bringing buses in and out of service. The lack of additional

66 https://www.climatexchange.org.uk/research/projects/the-impact-of-electric-buses-on-the-scottish-second-hand-bus-market/
67 https://www.cpt-uk.org/moving-forward-together
68 https://www.gov.uk/government/consultations/ending-the-sale-of-new-non-zero-emission-buses-coaches-and-minibuses

fixed infrastructure makes this approach more operationally flexible than opportunity charging.

- **Triaxle BEBs**: Buses with three axles can carry more weight and thus more batteries – potentially enough to meet the duty cycle requirements on a single overnight charge[69]. Increasing battery capacity and chassis size raises capital cost. The main limitation on the use of triaxle vehicles is their length and increased difficulty manoeuvring, which makes them unsuitable for many local roads, especially in suburbs, town centres, and on rural roads.
- **Hydrogen buses**: As discussed in 4.5.2, the cost of hydrogen fuel will be significantly greater than electricity. This means hydrogen buses are likely to be priced out of duties that can be operated efficiently with one of the BEB solutions above, even after the added costs of the pervious options have been considered. Exceptions may emerge where routes with high revenue earning potential can both benefit from hydrogen's operational flexibility and are able to sustain its higher costs. Operators that opt for hydrogen for one set of difficult routes may need to convert others to attain sufficient economies of scale locally – both fuel supply and maintenance expertise.

The table below evaluates each option.

TABLE 7: EVALUATION OF HYDROGEN ADOPTION RISK FOR BUSES

Option	City buses	Interurban buses	Rural buses	Suburban buses
Opportunity charged BEBs	Frequent services and common termini	Less frequent services and often dispersed termini	Infrequent services and dispersed termini	Less frequent service, but common termini
Extra BEBs with at-depot charging	Depots nearby	Depots often too remote	Depots often too remote	Depots often nearby with interworking of less frequent routes feasible
Triaxle BEBs	Unsuitable for some city centres and termini	Unsuitable for some termini and where accessing smaller settlements	Inadequate access to local roads	Inadequate access to local roads
Hydrogen buses	Adds operational flexibility, with potentially adequate revenue to cover extra costs	Potentially adequate revenue to cover extra costs	Policy sensitivity may encourage expansion of subsidies	Only where operating remote from depot
Likelihood of hydrogen	*10%*	*50%*	*30%*	*30%*

[69] Current triaxle bus and coach designs can already carry over 600kWh of batteries, up to 50% more capacity than two-axle buses - for example, https://www.alexander-dennis.com/alexander-dennis-unveils-its-first-zero-emission-three-axle-double-deck-bus-the-enviro500ev-charge-for-north-america/ and https://pelicanyutong.co.uk/gte14-the-first-tri-axle-battery-electric-coach/

4.6 TRAINS

4.6.1 APPROACH

The tables below summarise our approach to modelling potential hydrogen demand for trains, details of which are described in subsequent sections.

TABLE 8: APPROACH TO PASSENGER TRAINS

Action	Comment
Filter schedules for diesel passenger trains	Electric traction assumed decarbonised
Extract overnight stabling locations and activity from railway schedules	Assumed to be placed where refuelling could occur prior to each day's duty cycle
Relate trainset classes to typical duties	Excludes local services as certainly (battery) electric
Assign operator's diesel fleet to scheduled activity	Distributes operator's trainsets across scheduled duties, relating trains to overnight locations
Calculate daily mileage by train and derive hydrogen demand	Applies operator-specific daily trainset mileages
Assign likely year of decarbonisation	Based on rolling stock age and replacement cycle
Assess likelihood of hydrogen adoption	Compares hydrogen to other solutions

TABLE 9: APPROACH TO FREIGHT TRAINS

Action	Comment
Filter schedules for diesel freight trains	Locomotive positioning moves excluded
Factor scheduled activity down to adjust for occasional trips	Many scheduled trip paths are routinely unused
Estimate each scheduled trip's distance	From origin to destination terminal
Calculate energy and hydrogen requirements	Considering scheduled weight and trip distance
Reassign hydrogen demand to any dominant terminal	Where aggregate demand at either origin or destination far exceeds the other
Assign likely year of decarbonisation	Based on fleet age and replacement cycle
Assess likelihood of hydrogen adoption	Compares hydrogen to other solutions

4.6.2 CONTEXT

4.6.2.1 POLICY BACKGROUND

In England there is no clear proactive policy on railway decarbonisation, beyond the ambition contained in DfT's overall Transport Decarbonisation Plan[70]. This is despite DfT's effective control of almost all English railway investment and strategic operational decision-making. Only 38% of UK railway lines are currently electrified, well behind most Western European railway networks[71]. Railway investment life cycles often span decades, implying a rapidly diminishing window of time in which the wider 2050 Net Zero target can be met.

In 2020, national rail infrastructure manager, Network Rail concluded[72] that in almost all cases the logical decarbonisation pathway for trains in Great Britain involved the electrification of track. Electric railways are indeed "better railways"[73], not only decarbonising traction, but also lowering operating costs, improving reliability, and raising effective network capacity. Track electrification is also a proven technology, which should make rail decarbonisation less risky than the decarbonisation of other transport modes where new technology needs to be introduced.

The problem with Network Rail's strategy was the expense of track electrification, up to £3 million of capital investment per single track kilometre, including high voltage grid connections[74]. Network Rail's plan was simply too costly for the UK Treasury to agree to[75]. Alternative traction decarbonisation strategies, as discussed later in this section, could in some cases double the Total Cost of Ownership of rolling stock, yet still be the cheapest option for individual operators.

In the absence of central government commitment to track electrification, the British rail sector now needs to consider second best decarbonisation options – those which Network Rail initially dismissed[76] with, "battery and hydrogen technologies are *unsuitable* for long-distance high-speed and freight services as these services have higher energy needs than battery and hydrogen can provide." These conclusions appear to have been rooted in RSSB research[77] which discounted any fuel that would not allow *business as normal*, for example limiting the scope of battery trains to weights and volumes freed by the mere removal of diesel propulsion equipment.

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[70] https://www.gov.uk/government/publications/transport-decarbonisation-plan with RIA's analysis showing how little progress has been made since https://riagb.org.uk/RIA/Newsroom/Publications%20Folder/RIA_briefing_Transport_Decarbonisation_Plan.aspx

[71] https://alternative-fuels-observatory.ec.europa.eu/transport-mode/rail

[72] https://www.networkrail.co.uk/wp-content/uploads/2020/09/Traction-Decarbonisation-Network-Strategy-Interim-Programme-Business-Case.pdf

[73] Noel Dolphin, addressing the Rail Industry Association on the topic in 2023.

[74] https://www.modernrailways.com/article/electrification-prove-you-can-deliver-demands-dft Grid connection may need to be subsequently reinforced to support unanticipated increases in the volume of electric trains operating nearby.

[75] https://www.newcivilengineer.com/latest/30bn-rail-electrification-plan-blocked-by-treasury-13-12-2021/

[76] https://www.networkrail.co.uk/wp-content/uploads/2020/09/Traction-Decarbonisation-Network-Strategy-Executive-Summary.pdf

[77] https://www.rssb.co.uk/research-catalogue/CatalogueItem/T1145

These assumptions now need to be reappraised, because otherwise their logical conclusion is that currently non-electrified long-distance passenger and freight services will continue to produce emissions come 2050.

Non-track electrification solutions tend to suppose conceptual or trial-stage technology, which brings a further degree of technical uncertainty to an already uncertain policy and appraisal landscape. As hinted above, the increased operating costs implied by many of these solutions could challenge the rationale for providing certain services. However, since the Serpell Report in 1982[78] British politics has rejected any cost-driven reduction in the passenger railway network, while DfT's stated policy intention to grow railfreight[79] is likely to evoke indirect financial support[80].

In this sense, decarbonisation is not just a technical problem to solve, but core to a wider strategic railway funding dilemma that shows few signs of political resolution[81]. The modelling of railway decarbonisation presented here is consequently much more discussive than for other modes.

4.6.2.2 PASSENGER TRAINS

While battery electric passenger trains have a long history in a few niche operations[82], the technology has only reemerged as a mainstream rail decarbonisation solution over the last decade. Many European-based railway manufacturers now offer, or are actively developing, a battery electric passenger model suitable for local services.

Partial operation on electrified track, during which period the train "in-motion" recharges its batteries, is optimal where part of the route is already electrified. The volume and weight of batteries can be minimised accordingly, while much of the traction equipment is common. For example, Stadler delivered a batch of new battery-augmented Electric Multiple Units to Merseyrail, allowing services to extend over short non-electrified sections of track. Current Scottish plans[83] to electrify only fragments of the Fife Circle route presume this style of operation. 25KV AC overhead supplies have the theoretical potential to deliver relatively rapid charging over relatively small sections of electrified track, if local grid connections and substations can be appropriately reinforced.

Vivarail re-powered several ex-London Underground trainsets for battery-only operation and started development of trackside opportunity charging equipment. This technology avoids the requirement for track electrification by using short ground-level charging rails, which a charging shoe on the train connects to when the train is stationary. This charging rail is fed from line-side battery storage, which can be trickle-charged from the domestic power grid,

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[78] https://en.wikipedia.org/wiki/Serpell_Report

[79] https://www.gov.uk/government/news/government-sets-ambitious-target-to-grow-rail-freight-by-at-least-75 - a policy introduced by a Conversative Party government, which is also Labour Party policy, thus likely to be sustained long-term.

[80] This might include subsidies for Zero Emission fuels, or proxies such as reduced track access charges for freight trains – noting that European Union rail policy intended to remove, not promote, such proxy mechanisms should no longer be relevant to Great Britain.

[81] The *draft* status of the 2024 Rail Reform Bill serves as an example - https://www.gov.uk/government/news/ministers-set-out-blueprint-for-future-of-the-railways-through-draft-rail-reform-bill

[82] For example, the routine use of battery equipment on the Folkestone Harbour branch - https://en.wikipedia.org/wiki/British_Rail_Class_419

[83] https://www.transport.gov.scot/news/green-light-for-55m-scottish-government-investment-in-decarbonisation/

thus avoiding expensive high voltage grid connections or significant track-side engineering work. The Great Western Railway inherited and is now trialling the technology[84]. It is likely to be best suited to branch-line style operations, where each regularly repeated train trip requires roughly the same amount of energy to be replenished at the same location.

The modest pace of battery train development, and uncertainty around future track electrification, appears to have led another British operator of a large diesel passenger fleet, Northern Trains, to *hedge their bets*: Northern's rolling stock procurement framework requires the delivery of diesel trains capable of being "decarbonised mid-life" into battery electric[85].

Even where decarbonisation is being delayed, all current intentions point towards a role for batteries in local passenger trains. In contrast, while hydrogen fuel cell propulsion has been demonstrated for local passenger trains[86], no implementations are planned in Great Britain. At the time of writing, there is one test "HydroFLEX" passenger unit in Great Britain, which has been used to demonstrate operation up to 90 miles per hour, on gradients, and through tunnels[87].

In continental Europe, several hydrogen local passenger train fleets have been introduced over the last few years. 41 Alstom iLint trains entered regular service in Lower Saxony and Frankfurt Rhine-Main in Germany[88], with several smaller fleets expected to enter service in France and Italy. Many countries, including Canada, have tested hydrogen local passenger trains[89]. In practice these trains have proven both expensive to buy and difficult to operate. One of the pioneers of such trains, Lower Saxony, has since decided to decarbonise with battery[90], while Stadler note that[91], "the only time hydrogen trains usually win tenders in Germany is when hydrogen models are specifically requested".

However, hydrogen passenger trains may have markets at longer distance, especially where track electrification is missing or minimal. Stadler's fuel cell FLIRT trains[92] have been successfully introduced in San Bernardino in the United States, and California has since ordered additional intercity hydrogen trains[93]. Spanish manufacturer Talgo has started developing high speed hydrogen fuel cell trains[94]. In modelling potential hydrogen demand for passenger trains, it is consequently important to understand which types of passenger train better suit hydrogen or battery.

Weight constraints

Self-propelled passenger trains typically average about 40t per carriage (assuming equipment is evenly distributed across the trainset, which is increasingly common on modern Diesel

[84] https://news.gwr.com/news/great-western-railways-innovative-fastcharge-battery-train-trial-could-transform-uks-railway
[85] https://www.railwaypro.com/wp/northern-trains-to-acquire-450-trains/
[86] Prototyped as https://en.wikipedia.org/wiki/British_Rail_Class_799 and thereafter proposed as https://en.wikipedia.org/wiki/British_Rail_Class_600
[87] https://www.porterbrook.co.uk/innovation/hydroflex-cop
[88] https://www.alstom.com/solutions/rolling-stock/alstom-coradia-ilint-worlds-1st-hydrogen-powered-passenger-train
[89] https://www.cbc.ca/news/science/hydrogen-train-quebec-city-1.6888891
[90] https://www.railtech.com/rolling-stock/2023/08/09/german-hydrogen-pioneer-opts-for-battery-trains-for-remainder-of-fleet/
[91] https://www.hydrogeninsight.com/transport/hydrogen-will-almost-always-lose-out-to-battery-electric-in-german-rail-transport-train-manufacturer/2-1-1504868
[92] https://stadlerrail.com/en/flirt-h2/details/
[93] https://dot.ca.gov/news-releases/news-release-2023-034
[94] https://www.railway-technology.com/news/talgo-first-hydrogen-high-speed-train/

Multiple Units), rising to 60t for high speed intercity. Adding a margin of about 5t for the passengers brings the total to 45-65t distributed across 4 axles. In Great Britain, Route Availability limits[95] define the maximum axle load, which as the name suggests varies slightly by route, but typically limits weight at just over 20t per axle, or 80t per carriage. The scope for extra battery-related weight is thus in the order of 15-35t, depending on train specification.

Near-future battery density is about 0.2 kWh/kg, but this is expected to rise to about 0.25 by 2040 when many railway traction decarbonisation attempts are likely to be enacted. The 2400 kWh per day of energy assumed by the RSSB analysis[96] for a mid-distance passenger train is thus feasible within about 12t, distributed across an assumed three carriages. The 4620 kWh RSSB estimate for long-distance equates to 23t, which is broadly feasible given longer-distance trains tend to consist of more carriages. The RSSB work rejected any increase in carriage weight based on increased track degradation, which may become an extra cost[97], but is not strictly a limitation.

Volume constraints

Battery volume constraints are in the order of 50 kWh per metre cubed: 48m^3 for mid-distance passenger trains and 9m^3 for long-distance – in practice about a third and two thirds of a carriage dedicated to battery storage. That implies roughly a 10% and 20% reduction in passenger carrying capacity.

At current battery prices, batteries will add up to £0.5 million per train in capital cost, in the order of a 10-20% increase in overall capital cost. Electric traction is significantly cheaper to maintain and operate than diesel, although battery degradation implies multiple mid-life replacements of battery packs, especially where routinely in-motion or opportunity charging. Assuming a 10-yearly battery replacement cycle, long-run operating costs would rise by £1-1.5 million, which is a similar magnitude to the lifetime saving anticipated by moving from diesel to electric. Thus, for the Total Cost of Ownership change is assumed net neutral, leaving the main *cost* as 10% and 20% reductions in revenue earning potential.

Volumes and especially weights for hydrogen (even at 350 bar) are lower than batteries. Assuming a cautious 0.5 kg of hydrogen per km (diesel consumption on long-distance units is about 30% higher than average), long-distance hydrogen trains would need about 700kg and 30m^3. The far lower total weight makes it far easier to store the energy in one part of the train, in contrast to batteries, which would need to be distributed more evenly across all axles.

Value of capacity

The RSSB analysis concluded that mid and long-distance trains were destined for "diesel or biofuel" because while RSSB yielded to the need to refuel daily, they were unwilling to entertain any reduction in passenger capacity. But with those two non-Zero Emission fuels not sustainable decarbonisation options[98], the question becomes which of battery or hydrogen reduces passenger capacity the least, either as an absolute reduction, or by proxy of increased

[95] https://en.wikipedia.org/wiki/Route_availability
[96] https://www.rssb.co.uk/research-catalogue/CatalogueItem/T1145
[97] Based on current track access charges for freight, as analysed in 4.6.2.3, any additional weight-related cost is likely to be minor.
[98] HVO, even as a means of reducing emissions short-term, has been discounted as a fuel for rail. ERM analysis shows HVO production to be structurally supply-constrained and entirely likely to instead feed the production of SAF for aviation. The higher willingness of aircraft operators to pay is assumed to price terrestrial transport operators out of the market for HVO within the next decade.

train length. In broad terms, hydrogen occupies roughly a third the volume of batteries, however hydrogen is also more expensive as a fuel and both financially and practically riskier. This is where consideration of relative cost is relevant.

Pre-Covid passenger revenue covered about 60% of British railway operating costs[99], but this has dropped substantially since and a more pragmatic future assumption is 50%. So, in very crude terms, a 20% reduction in passenger capacity aligns to the equivalent of a 10% increase in overall cost, and a 10% reduction to 5% cost. Fuels (diesel and electricity) account for about 4% of overall sector costs (railway traction cost per train is somewhat higher for diesel, but not significantly so). It follows that every 100% increase in fuel cost aligns to an 8% reduction in passenger capacity.

A longer-distance diesel passenger train is assumed[100] to use under 2 litre/km, which at £0.50/litre (pre-2020s "red diesel" rates) costs roughly £1/km in fuel. An equivalent hydrogen train might use up to 0.5 kg/km at £7/kg, or about £3/km. Hydrogen roughly triples fuel cost relative to diesel.

This means hydrogen costs the equivalent of a 16% reduction in passenger capacity but requires only a third of the capacity reduction of using batteries. If electricity is assumed a similar fuel cost to diesel[101], then the only cost of batteries is their physical space, which is triple that of hydrogen. Our battery assessment does not include any increased cost of track maintenance, which could have a significant impact on overall operating cost.

Implied optimal decarbonisation technology

On these broad assumptions:

- Mid-distance passenger train: Factor of 10% cost/capacity for battery, vs 19% (16% + 3%) for hydrogen. Such trains are highly likely to convert to battery electric.
- Long-distance passenger train: Factor of 20% cost/capacity for battery, vs 23% (16% + 7%) for hydrogen. Hydrogen is a contender alongside battery.

In both cases, but especially long-distance passenger, partial track electrification would allow a portion of each train service's energy to be taken direct from the overhead supply. This potentially both reduces battery requirements (due to in-motion charging) and reduces the volume of hydrogen needed to be carried by the train, either of which would tilt the optimal solutions toward battery.

4.6.2.3 FREIGHT TRAINS

British railfreight operates in a liberalised commercial market, motivated primarily by the needs of freight customers. About 90%[102] of British freight train hauls use diesel locomotives. The best operator decarbonisation plans offer no detail on how Net Zero traction

[99] https://dataportal.orr.gov.uk/media/algdbizg/rail-industry-finance-uk-statistical-release-202223.pdf and https://www.nao.org.uk/wp-content/uploads/2021/04/A-financial-overview-of-the-rail-system-in-England.pdf
[100] The industry's "rule of thumb" of 1 litre per kilometre is skewed down by slower local trains, trains which are already assumed here to be battery operated. Longer distance trains both need to accelerate to higher line speeds and have greater "hotel" passenger-related energy requirements.
[101] An assumption discussed in the context of railfreight in 4.6.2.3.
[102] https://dataportal.orr.gov.uk/statistics/usage/freight-rail-usage-and-performance/

decarbonisation targets will be met[103]. Aside from track electrification, railfreight decarbonisation technology is nascent:

- Battery electric shunting locomotives are increasingly common[104], with small batteries starting to appear on bimodal freight locomotives to enable similar activity at terminals[105].
- Irish Rail is planning to trial hydrogen combustion in a retrofitted freight locomotive[106].
- Canadian Pacific is expanding its initial trial of hydrogen fuel cell freight locomotives[107], with several other North American corporations actively developing similar partnerships and technology.

CILT have shown[108] that 95% of diesel-hauled freight trains could shift to overhead electric traction with about 800 miles of additional track electrification. That implies a capital investment of about £2-3 billion to serve the requirements of about 500 freight locomotives, akin to £4-6 million per locomotive.

As explored below, this could be a plausible option to decarbonise railfreight when considered over a full 40-year locomotive working life, given the similarly high cost of decarbonisation alternatives. However, that would imply all railfreight operators agreeing to the same decarbonisation strategy and socialising the infrastructure investment through substantially higher track access charges. In practice this commercial risk would belong to Network Rail, which is ultimately a risk held by the British state. It would also require railfreight operators to price in the true costs of decarbonising their operations to the rates they charge their customers.

Any assessment of future railfreight fuels is complicated by the continued use of "red diesel"[109] with no equivalent subsidy or incentive available for Zero Emission fuels. The current fine balance between diesel and electric operating costs was recently exposed when several freight operators switched electric traction for diesel to reduce operating costs[110]. Broadly, the use of electricity may be presumed cost-neutral, while hydrogen at an optimistic £7/kg is likely to triple fuel costs from their pre-2020s baseline. However, because fuel is a relatively small proportion of overall train operating cost in Great Britain, substantial increases in fuel cost could still be manageable within existing business models[111].

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[103] GBRF https://www.gbrailfreight.com/wp-content/uploads/2023/05/GBRF-Carbon-Reduction-Plan-2023.pdf and Freightliner https://www.freightliner.co.uk/sustainability/decarbonisation/

[104] https://www.positivetraction.co.uk/ provide targets, while DB Cargo are merely "committed to helping UK government achieve net zero in 2050" https://uk.dbcargo.com/rail-uk-en/Our-Company/sustainability

[105] Stadler's class 93 features an 80kWh battery - https://en.wikipedia.org/wiki/British_Rail_Class_93_(Stadler)

[106] https://www.irishrail.ie/en-ie/news/iarnrod-eireann-and-latvia-s-digas-to-trial-europe

[107] https://railway-news.com/cpkc-orders-18-hydrogen-fuel-cell-locomotive-engines-from-ballard/

[108] https://ciltuk.org.uk/News/Latest-News/ArtMID/6887/ArticleID/37134/Rail-electrification-possible-for-95-of-UK-freight-trains-CILT-research-reveals

[109] https://www.gov.uk/guidance/using-rebated-fuels-in-vehicles-and-machines-excise-notice-75

[110] https://www.railtech.com/all/2023/07/25/db-cargo-uk-grounds-electric-fleet-following-rocketing-electricity-prices/

[111] Great Britain's railways are optimised for passengers, with freight is a marginal user. In contrast, North American networks are designed for freight, with passenger trains as marginal users. This flips cost structures, as demonstrated by ORR benchmarking - https://www.orr.gov.uk/sites/default/files/om/north-america-report.pdf - which shows railroad costs are 80-90% lower. That implies North American

Over the next decade, the railfreight sector will be able to sell its environmental credentials as "better than road". But thereafter the widespread adoption of battery electric trucks and the growing number of customers (both direct and indirect) requiring fully Zero Emission logistics to meet their own decarbonisation targets, could start to work against rail. Since this pressure will stem from individual freight customers on individual operators, not upon the whole railway network simultaneously, solutions are more likely to be delivered at train, not network, level.

Example freight locomotive use case

The heaviest sustained freight hauls in Great Britain will be used to illustrate the upper requirements of railfreight decarbonisation: Aggregate trains, specifically those from the Mendip quarries to terminals around London and the South East. Based on scheduled analysis detailed in 4.6.3, these trains average 3,100t (including locomotive and wagons) and 150km from origin to destination. The empty return is around a quarter of the outbound weight. The wide discrepancies between loaded and unloaded train weights make it important to model tonne-kilometres for freight trains, in contrast to passenger trains which can be adequately approximated by mere kilometres.

ORR statistics for annual railfreight diesel consumption[112] were divided into equivalent statistics for tonne kilometres (factored up from net to gross) to derive an average diesel consumption of 0.005 litres per tonne-kilometre. This consumption is modelled as 0.05 kWh/t-km of battery energy or 0.0015 kg/t-km hydrogen via fuel cell[113].

Indicative battery locomotive TCO

The example Mendip train would thus need upwards of 23 MWh of usable battery just to get from origin to destination. In practice a significantly larger capacity may be needed to enable operation in extreme weather conditions, but for simplicity of example, 25 MWh of installed battery is assumed. That implies:

- Roughly double the weight of the current 125t locomotives, while (assuming 50kWh per metre cubed) also requiring over 500 metres cubed of physical space, which in turn implies a triple chassis. These two extra chassis and associated control systems and bodywork might add a further £2 million to the existing diesel locomotive capital cost of about £5 million.
- Assuming current battery cost of about £100/kWh, the batteries alone would cost about £2.5 million. Battery degradation is difficult to predict in such a theoretical use case, but based on other heavy-duty vehicles, a 10-yearly replacement cycle is a reasonable assumption, which brings the (40 year) lifetime cost of batteries to £10 million, with the caveat that batteries are expected to halve in price during this life, so we assume £7 million for batteries overall.

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operators spending a higher proportion on fuel, and thus their business models being more sensitive to more expensive fuels. In practice freight market dynamics are complex. For example, an aggregate train from the Mendips to the London area might be sensitive to the relative price of shipping aggregate in from a coastal Scottish quarry instead. But there is a reasonable argument that British railfreight will not simply be priced out of its markets by switching fuels, because even a tripling of fuel costs should increase overall costs by under 10%.

[112] https://dataportal.orr.gov.uk/media/1993/rail-emissions-2020-21.pdf

[113] Using conversion factors of 10.56kWh energy per litre of diesel and 0.317kg of hydrogen per litre of diesel. These factors assume an energy density of 38 Megajoule per litre for diesel, and 33.3kWh per kg of hydrogen.

- Lifetime diesel fuel costs are estimated at about £7 million[114], and this cost is assumed to be unchanged by using electricity. Maintenance costs are assumed about £5 million over the life. Electric powertrains will offer maintenance cost savings, but these are likely to be nullified by the cost of installing and connecting very high-power chargers at multiple terminals to support relatively few locomotives.
- Network Rail charges[115] around £4 per thousand gross ton miles for bulk freight, so every mile the extra 100t of batteries travels costs 40p. This will add no more than £1 million to lifetime operating costs[116].

In very rough terms, the Total Cost of Ownership of an existing diesel is estimated in the order of £15-20 million, with the cost of a battery equivalent in the order of £25-30 million.

Indicative hydrogen locomotive TCO

The equivalent hydrogen fuel cell powered haul would require about 700 kg of hydrogen, perhaps 1 t or more as combustion. 700kg would occupy just over 30 m^3 of storage at 350 bar, with higher pressure reducing volumes further. That volume is under 20 % of total locomotive volume, so might be designed onto one chassis, or might need a hydrogen tender (a technology currently under test in Canada[117]). Fuel cells would require some batteries to manage acceleration, but likely in the low hundreds of kWh, so relatively insignificant compared to the battery-only case above. Like batteries, fuel cells are likely to need replacement over the life of the locomotive.

So, while the capital cost of a hydrogen fuel cell locomotive will be greater than a diesel, it is likely to be far cheaper to acquire than the equivalent battery locomotive. Hydrogen as combustion should broadly match the capital cost of an existing diesel. In both cases there will be costs establishing a hydrogen fuelling station, but because hydrogen requires far less space, it is much more practical to fuel locomotives for a round trip, avoiding the need to install fuelling facilities at multiple destination terminals, and instead concentrate infrastructure investment at the common origin.

The key determinant is likely to be hydrogen price, which even at £7 /kg will roughly triple fuel costs, to around £20 million over a 40-year life, and thus push the overall Total Cost of Ownership of a hydrogen freight locomotive in the order of £30-35 million, roughly double that of diesel.

While the headline case for hydrogen is weaker than battery, hydrogen's flexibility has tangible value: In the aggregate sector, where a single quarry is the constant and the use of delivery terminals can change over time depending on end-user demand, the flexibility of only needing one fuelling site has tangible value. In contrast, a battery locomotive capable of charging in just one location would require at least 30MWh of battery energy, narrowing the gap in Total Cost of Ownership considerably. Likewise, the grid and/or downtime implications of charging

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[114] 500 active diesel freight locomotives divided into (ORR's) 172 million litres of diesel a year is about 350,000 litres per locomotive per year, or 14 million litres of diesel over 40 years. Assuming (red) diesel costs the operator about 50p per litre (pre-2020s), lifetime fuel cost is about £7 million.

[115] https://www.networkrail.co.uk/industry-and-commercial/information-for-operators/cp6-access-charges-2/

[116] Assuming 20 million freight miles annually across a 500-locomotive fleet, we expect about 40,000 miles per locomotive per year, or 1.6 million miles in a lifetime, which at 40p/mile is an extra 0.6 million on lifetime costs.

[117] https://www.railjournal.com/regions/north-america/cpkc-trials-use-of-hydrogen-tender/

such a large capacity battery could be significant, in contrast to hydrogen which broadly mimics diesel fuelling.

Implied optimal decarbonisation technology

In both battery and hydrogen cases explored above, the additional lifetime cost of locomotive decarbonisation (£10-15 million per locomotive) emerges as significantly higher than the socialised cost of freight-specific track electrification (£4-6 million per locomotive cited at the start of this section). However, there are two further considerations which tend to bring these figures much closer together:

- Where a proportion of the route is already electrified traction should be able to switch to overhead supply or even in-motion charge, reducing the on-board energy requirements specified above, and thus costs. The scope for such reductions, if any, will vary by route.
- The average scheduled diesel freight train weighs about 1,300t, less than half of our Mendip example. In the *average case*, the cost of decarbonising the locomotive alone (with batteries or hydrogen) will be akin to the cost of socialised track electrification.

The analysis here serves only to demonstrate that all the railfreight decarbonisation options outlined could have broadly similar magnitudes of cost. The solution for each freight market could ultimately differ, perhaps dependent on factors such as how centralised the source of the cargo is, or what proportion of the trip is already over electrified track.

There is a risk that the relatively small size of the British fleet results in certain options never materialising as commercial products. The greater extent of continental Europe's existing track electrification may generate few commercial opportunities for either large battery or hydrogen locomotives, which in turn provides European-focused manufacturers with insufficient economies of scale. Instead, whatever solution eventually emerges from North America, where track electrification is minimal, could transpire to be the only technologically mature import available. While all known heavy-haul locomotive development programmes in North America assume hydrogen, with battery locomotive trials so far consigned to shunting roles[118], it is far too early to conclude that hydrogen power will ultimately dominate railfreight in North America.

The railfreight sector offers hydrogen a unique advantage over most modes of transport – the potential for synergy with industry. British railfreight naturally gravitates towards large industrial sites where hydrogen may be required as industrial energy. In these cases, the ability to fuel a locomotive may be considered a marginal use case, albeit one still critical to the successful operation of that industry. This is the main reason for considering hydrogen combustion for freight locomotives, since combustion can directly use the impure pipeline fed hydrogen anticipated in industry – gas which cannot be used in fuel cells without expensive purification. While combustion emits other noxious gases, these are less likely to raise local objections than on road, because of the remoteness of many railfreight operations from centres of population.

But even where railfreight operations are not linked to industry sites, the daily volume of hydrogen required by each locomotive is such that relatively few locomotives would be needed to make hydrogen supply reasonably efficient. Combined with the natural tendency for British

[118] https://cleantechnica.com/2023/11/07/u-s-steel-pioneers-battery-powered-locomotives-1st-in-north-america/

railfreight operations to concentrate[119], rail should be the easiest transport market to scale appropriately.

4.6.3 DEMAND MODELLING AND ASSIGNMENT

4.6.3.1 DATA SOURCES

Network Rail open data schedules[120] were extracted for the Summer 2023 timetable. Schedules include data that allows electric traction to be identified and excluded[121]. Passenger trains were identified, via schedule data, by vehicle class or type, and operator. Freight trains were identified by gross weight and customer sector.

Locations used geospatial coordinates compiled by GB Railway Data[122]. Origin-to-destination distances were approximated using Haversine (direct line) distances, multiplied by 120%, to account for the indirectness of rail routes. This factor was derived by testing a sample of trips against network maps.

4.6.3.2 PASSENGER TRAINS

For passenger trains, existing overnight stabling or maintenance locations were assumed to be the places trains would refuel in future. Almost all passenger trains services start and finish their daily duty at one of these locations. There is no standard list of such facilities, in part because activity ranges from a siding used to berth the train, through a set of sidings also providing fuel and light maintenance, to major depots providing all this plus heavier maintenance. Instead, these locations were assumed to be origins or destinations which are not passenger stations but are used by passenger trains.

The average number of weekly passenger train moves scheduled to depart between 02:00 and 08:00 was used as a proxy for the proportion of each operator’s total diesel fleet using that depot overnight. This proxy method assumed all trains of the same operator consist of roughly the same number of carriages per unit. A unit is a permanently coupled set of self-propelling carriages. An in-service passenger train is made up of one or more units.

For each operator and vehicle class/type (as identified in the schedules), current unit fleet size was researched from enthusiast sources, expected replacement date assuming a 35-year life[123], and an assessment made of the broad category of duties that vehicle was most likely to be assigned to. In some cases, the current duty type is more local or suburban than the rolling stock was originally designed for. For example, all older class 15x units operated by Northern Trains were assumed to operate on duties scheduled as local “Sprinter” (up to 75 miles per hour), even though class 158 rolling stock was originally introduced for mid-distance “Express Sprinter” (up to 90 miles per hour) services.

The number of units derived above was reduced by 10% to reflect the proportion of the fleet expected to be unavailable for passenger service, typically for heavy maintenance or due to

[119] As modelled, half of all British railfreight demand for hydrogen would occur across the top 20 locations.
[120] https://www.networkrail.co.uk/who-we-are/transparency-and-ethics/transparency/open-data-feeds/
[121] Bimodal (diesel and overhead electric) trains are filtered based on their traction mode at the start of their journey, which crudely averages out diesel and non-diesel use.
[122] https://railmap.azurewebsites.net/Downloads
[123] https://www.riagb.org.uk/RIA/Newsroom/Publications%20Folder/The%20UK%20Rolling%20Stock%20Industry.aspx

equipment failure. Each operator/duty scheduled overnight depot move was then weighted in proportion to this number of trains, to give an estimate of the number of trains that would be refuelled in each location.

Duties highly likely to convert to overhead electric following the completion of TransPennine or Midland Mainline track electrification schemes were assumed to do so. Other large electrification schemes where funding commitments and timelines were judged insufficiently certain, such as the North Wales coast, were ignored. Fleets already being replaced (with specific rolling stock orders) were assumed to adopt their new train type. As discussed in 4.6.2.2, local trains were assumed to convert to battery electric, and were thus excluded from assessment of potential hydrogen use. Charter trains, which typically showcase historic rolling stock, were ignored.

Each operator's average daily mileage per unit was estimated by dividing operator-specific statistics for passenger train kilometres into those for trains planned[124], with the result weighted by the estimated number of train units coupled together per operator (typically between 1 and 2 units) and factored for an assumed 90% fleet availability. Derived values varied from 400 kilometres per unit per day for entirely suburban operators, to over 1000km for solely intercity operators.

Potential hydrogen demand for each unit was then calculated at 0.5kg/km. This demand was assigned to the year period containing the existing vehicle's replacement date. The allocation of risks reflected the rationale presented in 4.6.2.2.

4.6.3.3 FREIGHT TRAINS

Most diesel freight locomotive are currently fuelled at dedicated maintenance facilities, although the use of bowsers (road tankers) can occur. As outlined in 4.6.2.3, the high energy requirements of freight trains effectively force a change in fuelling strategy, to in future fuel before each trip. Likewise, the natural synergy between freight and industry may make future fuels more readily available at industrial sites than at existing depot locations. As such, current depot-based operations, including "light locomotive" positioning moves without wagons, were ignored, and analysis conducted only on freight flows.

Traction, tonnage, and industrial sector were provided in the Network Rail schedule data. The main complication in analysing these was that many freight train paths are routinely unused. These "Q-coded" trains were not always accurately labelled in the schedule data, while in practice trains serving certain sectors, notably aggregates, appeared to be more likely not to operate than trains serving intermodal traffic.

To better factor these occasional trips, annual statistics[125] for diesel-hauled railfreight were applied to current schedules so that the overall tonnage and distance modelled matched prior statistical patterns. Q-coded trains were assumed to operate with half the frequency of non-Q trains, a pattern derived from analysis of a small sample of performance data[126]. This effectively reduced the number of diesel-hauled non-Q trains to 42% of that in the schedule, and 21% for Q-coded trains. In practice some locations and operations will be more biased

[124] https://dataportal.orr.gov.uk/statistics/compendia/toc-key-statistics/
[125] https://dataportal.orr.gov.uk/statistics/usage/freight-rail-usage-and-performance/
[126] Observations via https://www.realtimetrains.co.uk/

towards trains running than others, so this factoring induces a significant margin of error at local site level. It does not however alter overall totals.

Potential hydrogen demand was initially modelled as 0.0015 kilograms per tonne kilometre, assuming fuel cell technology. However, given the synergy with industry of using hydrogen combustion technology for railfreight (as discussed in 4.6.2.3), an uplift of 20% was applied to the total hydrogen demand values to represent a proportion of demand occurring from inefficient hydrogen combustion. This uplift conflated two unknowns, both the proportion of hydrogen as combustion and its inefficiency related to fuel cells. Fuel cells are typically held to be considerably more efficient than combustion, although relevant studies tend to derive from small vehicle trials, not railway locomotives[127].

Operators of freight trains serving minor routes or terminals will rationally seek to avoid the requirement to install expensive fuelling or charging equipment at those minor terminals, and instead simply carry sufficient fuel to complete an out-and-back round trip. The total hydrogen demand initially modelled above was summed by location. On routes where demand (from all railfreight) at origin or destination location was more than three times the other, and the minor location of the pair totalled less than 1 tonne per day (indicative of the approximate scale at which hydrogen supply tends to become efficient), that demand was instead assigned to the major location of the pair.

Freight locomotives can last over 40 years in active service, especially with refurbishment. By far the most common current design of locomotive, the class 66, typically dates from the 2000s[128]. This means the bulk of the fleet will last, or can be made to last, well into the 2040s. The current state and future cost of railfreight decarbonisation technology means operators have a strong incentive to maintain their current fleet until action on Net Zero objectives becomes unavoidable, either by legislation or competitive customer pressure. As previously discussed, that customer pressure is likely to start emerging in the 2030s, and may create market opportunities for an expensive, but genuinely zero emission, railfreight service.

The assumption made was thus that only 25% of fleet replacement would occur in the 2030s, with the remaining 75% in the 2040s. These proportions were distributed evenly across all types of freight operation. In practice, akin to the assignment of HGV demand, certain freight flows in certain locations are likely to entirely decarbonise in the same period because of the need to support new locomotives with new fuelling infrastructure.

4.6.4 RISKS

As discussed in 4.6.1, all potential hydrogen applications presume insufficient track electrification. A lack of national government commitment to track electrification, combined with the long timescales to deliver it, suggest there is a strong chance that track electrification will be insufficient by the time rail operators seek to decarbonise their traction.

For passenger trains the balance between the two reasonable alternatives to track electrification – battery and hydrogen – was discussed in 4.6.2.2. Each category of train raises further issues, which also feed into our assessment of likely decarbonisation pathways:

[127] https://www.cummins.com/news/2022/01/27/hydrogen-internal-combustion-engines-and-hydrogen-fuel-cells
[128] https://en.wikipedia.org/wiki/British_Rail_Class_66

- **Intercity trains** are those operating at over a hundred miles per hour, with routes centred on London or Birmingham. The adherence of these long-distance trains to mainline routes, most likely to already be engineered for heavy freight trains, suggests weight will not be a limiting factor, although may substantially increase track access charges.
  - Intercity trains operating primarily under electrified track are highly likely to favour bimodal battery/overhead operation over hydrogen, due to the ease of in-motion charging and the consequent reduction of their onboard battery capacity requirement. A 10% likelihood of adopting hydrogen has been assumed, primarily reflecting the immaturity of battery train technology at higher speeds and longer ranges.
  - Those operating primarily away from electrified track have a much stronger chance of adopting hydrogen, assumed 50%. This reflects the relatively high proportion of passenger-carrying capacity that would be lost to battery electric, and in some cases (notably routes to London) the difficulty simply extending train length to compensate. The main risk to hydrogen is targeted track electrification. For example, the extension of electrification from Bristol and Newbury to Exeter would allow almost all these trains to operate primarily on overhead electric supplies, which tilts the optimal solution away from hydrogen, towards large, in-motion charged battery trains.
- **Regional trains** are mid-distance services, excluding primarily local or suburban services, typically between regional towns and cities using short two or three carriage units and operating up to 90 miles per hour. A 10% chance of adopting hydrogen is assumed because of the high degree of uncertainty around the decarbonisation pathway of these services. Many diesel trains used here are expected to become life-expired within the next 10 years, yet battery train technology for such ranges is not yet proven in Great Britain. Many such services are commercially weak, so expensive decarbonisation technology is likely to make a poor business case for investment. However, the political risk, for example in reducing regional connectivity by curtailing longer routes, is tangible. This could promote viable, but expensive, solutions. New build with conversion to battery much later in life seems the most likely option, but potentially challenging to design because of the difference in volume and weight between current diesel engines and expected future battery equipment.

As discussed in 4.6.2.3, all railfreight decarbonisation solutions are likely to add similar magnitudes of cost, and in this context hydrogen propulsion should be considered a realistic option. Hydrogen is especially likely where freight emanates from one common origin hub to many destinations (because of the operational flexibility of potentially only needing to refuel hydrogen at the origin) and where little or no in-motion charging is possible due to a lack of track electrification (or adequate electricity supply).

This has resulted in slightly different assessments of risk for each category of railfreight train, based on the tendencies of trains in each category:

- **Railfreight distribution** trains consist primarily of intermodal cargo, especially maritime containers. Cargos tend to be lighter than on Trainload bulk and metals trains, more likely to pass under overhead-electrified sections of track, and loads more evenly balanced in each direction, but the distances travelled tend to be further. Railfreight distribution is judged the least likely freight sector to adopt hydrogen, at 30%, because its operations tend to be focused on core routes, especially those between ports and big cities, where at least part of the route either operates over sections of electrified track or has the potential to do so.

- **Railway engineering** trains are those operated to move railway maintenance materials and equipment around the network[129], not the operation of that equipment to maintain infrastructure (which is outside the scope of this modelling). Most mimic the requirements of Trainload bulk and metals, but a third have far lighter or shorter distance requirements, so overall likelihood of hydrogen is assumed slightly lower, at 40%.
- **Trainload bulk and metals** trains primarily carry aggregates, including all the heaviest trains operated in Great Britain. These typically travel shorter distances than Railfreight distribution, with an empty return haul as low as a quarter of the net weight of the outbound loaded train. A 50% likelihood of adopting hydrogen is assumed: Hydrogen is better suited to the Trainload's focus on common origins, such as quarries, combined with higher powers and shorter distances, compared to Railfreight distribution, which reduce the likelihood of being able to in-motion charge for a sufficient part of a journey to suit battery electric. The weight of bulk goods can make their distribution by rail price sensitive vs alternative modes or material sources – there is a risk that any decarbonisation option will alter overall market competitiveness for the cargo.

[129] In practice railway engineering is the smallest of the three freight train classifications modelled, totalling less than 10% of all freight by weight or distance. The grouping has been analysed separately for clarity since many "freight" statistics and assessments exclude railway engineering trains. Railway engineering trains are unlikely to be a large enough segment to warrant a dedicated fleet with a unique decarbonisation technology.

5. APPENDIX: EXISTING & PLANNED HYDROGEN REFUELLING STATIONS IN THE UK

Another way of looking at the problem is to consider where existing and planned hydrogen refuelling stations are in the UK. These stations are mapped against the NTS in Figure 16 and listed in Table 10. Efforts have been made to ensure that the Figure and Table include all known stations in the UK that are operating or planned, however, it cannot be guaranteed that the list is fully comprehensive, given that the picture of refuelling stations in the UK is constantly evolving.

As shown in Figure 16, there are several existing stations in the UK, including a combination of public refuelling stations and private stations (e.g. Crawley and Perivale, which are private stations serving a fleet of hydrogen buses). It should be noted that the future of many existing stations is uncertain, having been built for small-scale demonstrations of hydrogen fuelled vehicles. However, stations such as Crawley were recently developed to fuel a fleet of hydrogen buses operating on routes that would be challenging to electrify, so are likely to have more long-term potential.

There are also tens of stations planned to come online in the next few years, shown in Figure 16, which are likely to be larger-scale and have greater long-term potential. These projects have received funding under several different Government schemes, some of which are focussed solely on mobility as an end use:

- **Tees Valley Hydrogen Transport Hub**, a scheme to support hydrogen-powered transport in the North East of England, with vehicle demonstrations to start from October 2024[130].
- **Zero Emission HGV & Infrastructure scheme (ZEHID)**, a scheme to increase zero emission road freight in the UK. Vehicle demonstrations are required to begin by end of 2026[131].

There is also potential for mobility demand as a result of new large-scale hydrogen production projects funded through schemes such as:

- **Net Zero Hydrogen Fund** (only those with stated mobility end-use have been included).
    - Strand 2 competition, which provides CAPEX support for hydrogen production projects (projects funded in round 1 and 2 must be built by end of March 2025[132]).
    - Hydrogen Allocation Rounds, which provides revenue support for hydrogen production projects (projects funded in round 1 must be in operation by December 2025).

However, for many of these projects, the amount of the overall production capacity that will be attributed to mobility is not clear.

[130] Competition overview - Hydrogen Transport Hub Demonstration Phase 2 - Strand 1 - Innovation Funding Service (apply-for-innovation-funding.service.gov.uk)
[131] ZEN Freight project re-groups after bp withdraws from DfT-funded ZEHID trials | Article | Freight Carbon Zero
[132] Round 1 competition details: Competition overview - Net Zero Hydrogen Fund – Strand 2 – Capital expenditure (CAPEX) - Innovation Funding Service (apply-for-innovation-funding.service.gov.uk), Round 2 competition details: Competition overview - Net Zero Hydrogen Fund: Strand 2 Capital Expenditure Round 2 - Innovation Funding Service (apply-for-innovation-funding.service.gov.uk)

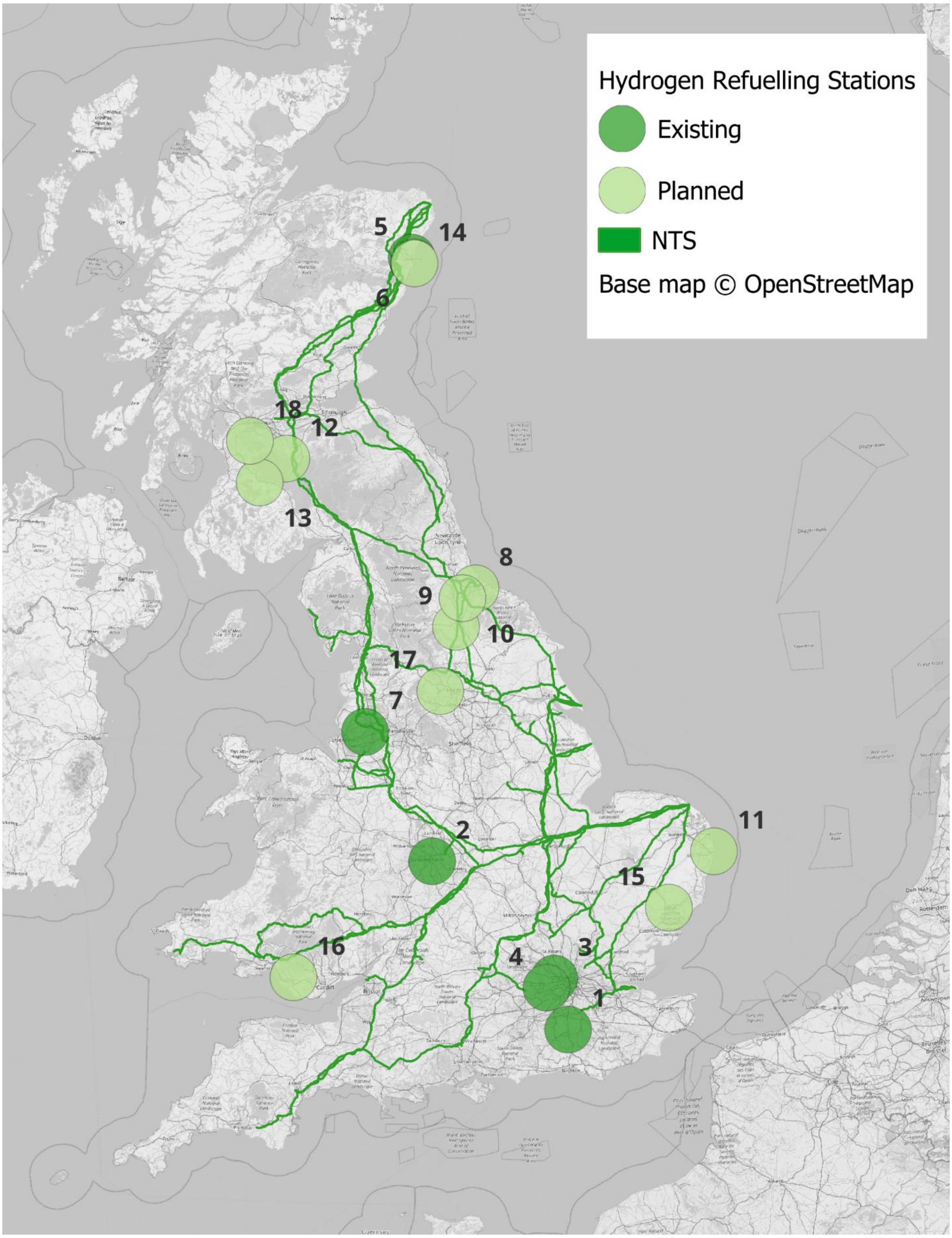

FIGURE 16: MAP SHOWING EXISTING AND PLANNED HYDROGEN REFUELLING STATIONS IN THE UK, MAPPED AGAINST THE NTS (BASE MAP © OPEN STREET MAP). NOTE, EXACT LOCATIONS OF MANY OF THE PLANNED STATIONS IS NOT CONFIRMED, SO APPROXIMATE LOCATIONS ARE SHOWN ON THE MAP.

#	Project name	Project / station details	Location
Existing stations			
1	Crawley	350 bar; private bus refuelling	West Sussex
2	Tyseley Energy Park	350 and 700 bar; public	Birmingham
3	Perivale	350 bar; private bus refuelling	Perivale
4	Hatton Cross	350 and 700 bar; public	Hatton Cross, London
5	Kittybrewster, Aberdeen	350 and 700 bar; public	Aberdeen
6	ACHES, Aberdeen	350 and 700 bar; public	Aberdeen
7	St Helens	350 bar	Merseyside
Tees Valley Hydrogen Transport Hub projects[133] - from October 2024			
8	Tees Valley Hydrogen Vehicle Ecosystem	25 HGV FC vehicles, one hydrogen refuelling station	Tees Valley, North East
9	Zero Emission Hydrogendemonstration in Airport Applications	Demonstrate range of hydrogen-fuelled airside vehicles at Teesside International Airport and RAF Leeming	
10	Teesside International Airport Refuelling Hub	Publicly accessible station at Teesside International Airport to serve airport operation vehicles and supermarket deliveries	
Net Zero Hydrogen Fund, Round 1, Strand 2 winners (CAPEX funded) with mobility focus – production online by March 2025[134]			
11	Conrad Energy Hydrogen Lowestoft	2 MW (0.4 tpd), fuel for marine vessels	Lowestoft, East Suffolk
12	Octopus Lanarkshire Green Hydrogen	15 MW (2.5 tpd), for transport and industrial applications	Lanarkshire, Scotland
13	Knockhinnoch Green Hydrogen Hub	2.5 MW (0.4 tpd), decarbonisation of bus and truck fleets	East Ayrshire, Scotland
Net Zero Hydrogen Fund, Round 2, Strand 2 winners (CAPEX funded) with mobility focus – production online by March 2025[135]			
14	Aberdeen Hydrogen Hub	0.8 tpd, sufficient to fuel 25 FC buses and fleet of council vehicles	Aberdeen, Scotland
15	Suffolk Hydrogen Hub	10 MW (4 tpd), buses for Sizewell C and other offtake in the Suffolk and East Anglia region	Suffolk, East

[133] Tees Valley hydrogen transport hub: successful bidders - GOV.UK (www.gov.uk)
[134] Net Zero Hydrogen Fund strands 1 and 2: summaries of successful applicants round 1 (April 2022) competition - GOV.UK (www.gov.uk)
[135] Net Zero Hydrogen Fund strands 1 and 2: summaries of successful applicants round 2 (April 2023) competition - GOV.UK (www.gov.uk)

HAR1 projects with mobility focus – production online by December 2025[136]			
16	HyBont	5.2 MW, for transport (trucks & buses) and industry	Bridgend, Wales
17	Bradford Low Carbon Hydrogen	24.5 MW, project will include a hydrogen refuelling station for buses, public and private sector fleets	Bradford, Yorkshire
18	Whitelee Green Hydrogen	7.1 MW, hydrogen will be used to fuel public transport and heavy freight vehicles	Whitelee, Scotland
Zero Emission HGV & Infrastructure Demonstrator – must begin demonstration by end of 2026			
19	ZEN Freight[137]	16 hydrogen HGVs and multiple combined hydrogen refuelling & electric recharging sites	North of England (exact locations TBC)
20	HyHaul[138]	30 hydrogen HGVs and four public refuelling stations by 2026, ambition for 300 HGVs by 2030	M4 corridor in the South West & Wales (exact locations TBC)

TABLE 10: LIST OF EXISTING AND PLANNED REFUELLING STATIONS IN THE UK[139].

[136] Hydrogen Production Business Model / Net Zero Hydrogen Fund: HAR1 successful projects (published December 2023) - GOV.UK (www.gov.uk)
[137] ZEN Freight project re-groups after bp withdraws from DfT-funded ZEHID trials | Article | Freight Carbon Zero
[138] PROTIUM LAUNCHES THE FIRST OF ITS KIND GREEN HYDROGEN PROJECT TO DECARBONISE UK ROAD TRANSPORT - Protium
[139] Note, the ZEN Freight and HyHaul projects have not been included on the map in Figure 16 since the exact locations of the stations for these projects has not yet been confirmed.

6. APPENDIX: HYDROGEN HUB ANALYSIS

6.1 HYDROGEN DISTRIBUTION COST MODEL

To reflect the current projections of energy and equipment costs, the business case prepared in the Alpha phase of the project was reviewed and updated, considering eight different hydrogen distribution scenarios:

Transitional supply archetypes:

1. Centralised hydrogen production with de-blending only
2. Centralised hydrogen production with de-blending at regional hub and local tube trailer delivery
3. Regional hydrogen production with localised tube trailer delivery
4. Centralised hydrogen production with national tube trailer delivery

Long-term supply archetypes:

5. Centralised hydrogen production with transport through repurposed pipelines
6. Centralised hydrogen production with transport through repurposed pipelines to regional hubs and local tube trailer delivery
7. Regional hydrogen production with localised tube trailer delivery
8. Centralised hydrogen production with national tube trailer delivery

The key general parameters for the analysis are as follows:

- Scale of hydrogen demand is 5 tonnes per day.
- Years: 2040 and 2050 considered to reflect the transition and long-term respectively.
- Tube trailer delivery distance: a range of values is provided for the tube trailer costs, considering driven distances of 50km for local distribution and 250km for national distribution depending on archetype.
- Variable blend: the deblending costs used assume a variable blend profile, as this is consistent with the centralised hydrogen production value used (which assumes the majority of the electrolyser electricity is provided by directly connecting to renewable assets).
- HRS CAPEX and OPEX: values are not included in the LCOH comparisons as they will vary depending on the size of the end-use demand. Further details for this rationale are provided in the caveats below.
- Tube trailer CAPEX and OPEX values are provided assuming delivery to a 5tpd station. The tube trailer costs shown in the LCOH analysis include trailer and truck CAPEX, fuel costs, driver cost and cost of compression into tube trailer. Note, compression is only required for archetypes 3, 4, 7 and 8 where there is no pipeline transport, since electrochemical purification can pressurise hydrogen up to high pressure as part of the process, which reduces the need for additional compression).

- Electricity sourcing for electrolyser: the regional production case assumes 100% grid electricity, whereas the centralised production case assumes a rough split of 50:50 renewables (50:50 solar and wind) to grid electricity. This approach has been taken as it is not reasonable to assume that all regional sites could have a direct connection to renewables, whereas large centralised sites will be located next to dedicated renewables.

Key assumptions are detailed in the Table below.

TABLE 11: TABLE OUTLINING KEY ASSUMPTIONS USED IN THE BUSINESS CASE MODELLING.

Input	**Unit**	**Value**	**Source**
Centralised hydrogen production			
Hydrogen production cost	£/kg	3.82 (2040)	Based on optimistic electrolyser CAPEX and wind and solar CAPEX and grid electricity projections for 2040
		3.65 (2050)	Based on optimistic electrolyser CAPEX and wind and solar CAPEX and grid electricity projections for 2050
Electrolyser CAPEX	£/kg	425 (2040)	Based on optimistic future projections from ERM electrolyser CAPEX review
		320 (2050)	
Wind turbine CAPEX	£/MW	1,130,000 (2040)	World Energy Outlook 2023 – Analysis - IEA; technology costs for Europe
		1,100,000 (2050)	
Solar CAPEX	£/MW	350,000 (2040)	World Energy Outlook 2023 – Analysis - IEA; technology costs for Europe
		320,000 (2050)	
Size parameters for centralised production			
Electrolyser capacity	MW	200	Indicative size of a large-scale hydrogen production project, see examples such as Holland Hydrogen I
Wind capacity	MW	200	Combined capacity to provide ~50% electricity requirement for electrolyser with remaining 50% supplied by grid. Scale of renewables similar to large-scale hydrogen production projects, see examples such as Holland Hydrogen I (200MW 100% supplied by a 759MW wind farm)
Solar capacity	MW	200	
Repurposed pipeline parameters for centralised production			

Input	Unit	Value	Source
Repurposed pipeline CAPEX	£/km	261,000	Value based on medium scenario cost estimates based on gas TSO's preliminary R&D efforts regarding hydrogen infrastructure from: ehb-report-220428-17h00-interactive-1.pdf (note: for small diameter pipelines <20 inches)
Repurposed pipeline length	km	200	Indicative length used for transportation distance from centralised production to NTS offtake point. This value is also used for the European Hydrogen Backbone study.
Pipeline diameter	inch	20	Small pipeline size diameter used for European Hydrogen Backbone calculations: ehb-report-220428-17h00-interactive-1.pdf (CAPEX source provides values for repurposed pipelines 20 inches in diameter).
Pipeline capacity	GW	1.2	Value used in European Hydrogen backbone study: ehb-report-220428-17h00-interactive-1.pdf
Pipeline maintenance costs	% of CAPEX	0.9	ehb-report-220428-17h00-interactive-1.pdf
Compressor CAPEX	£/MW	3,400,000	ehb-report-220428-17h00-interactive-1.pdf
Compressor maintenance costs	% of CAPEX	1.7	ehb-report-220428-17h00-interactive-1.pdf
Pipeline lifetime	yrs	40	ehb-report-220428-17h00-interactive-1.pdf
Compressor lifetime	yrs	25	ehb-report-220428-17h00-interactive-1.pdf
Repurposed pipeline LCOH	£/kg	0.044	Value from European Hydrogen Backbone estimates: ehb-report-220428-17h00-interactive-1.pdf (includes pipeline capex and compression) and uses key parameters outlined in the rows above.

Regional hydrogen production			
Hydrogen production cost	£/kg	5.63 (2040)	Based on optimistic electrolyser CAPEX and grid electricity projections for 2040.
		5.36 (2050)	Based on optimistic electrolyser CAPEX and grid electricity projections for 2050

Electrolyser CAPEX	£/kg	870 (2040)	Based on optimistic future projections from ERM electrolyser CAPEX review.
		650 (2050)	
Size parameters for regional production			
Electrolyser size	MW	50	Aligns with electrolyser capacities of regional production projects ERM has been involved with.
General parameters			
Electricity price	£/MWh	95	Internal ERM electrification cost model (UK retail electricity price in 2040)
		93	Internal ERM electrification cost model (UK retail electricity price in 2050)

Caveats

CAPEX assumptions: CAPEX assumptions used for the electrolyser, wind and solar represent optimistic cases with large reductions in CAPEX from current levels and therefore are not guaranteed.

HRS considerations: refuelling costs will vary depending on the specific scenario, so were not included as part of the levelised cost of hydrogen modelling. For example, in the scenario with regional deblending and local tube trailer distribution, tube trailers are likely to distribute hydrogen to several smaller scale stations (e.g. for a 5 tpd deblending facility, this could be 5 x 1 tpd stations). Whereas, in the scenario where the HRS is directly connected to the deblending facility, there will be a single large-scale station (e.g. 5tpd station assuming a 5tpd deblending facility). The exact cost will vary depending on the number of smaller stations deployed, however, the cost of a single large-scale station will be less than multiple smaller stations due to economies of scale.

Tube trailer delivery considerations: In the scenarios considered, differentiation is not made between delivery to multiple or singular HRS. Since tube trailers are modular (capacity assumed to be 670kg per trailer), there is not a significant difference in cost, as the distance travelled will be the same for all trailers regardless of whether travelling to a single large HRS or individual trailers travelling to a smaller HRS (assuming distance assumptions used in the analysis).

Hydrogen compression for tube trailer v pipe scenarios considerations: for scenarios where hydrogen is first distributed via pipeline, costs for compression (either into a tube trailer or directly into a refuelling station) are not included because the electrochemical purification can pressurise hydrogen up to high pressure as part of the process. On the other hand, in scenarios where hydrogen is transported via tube trailer direct from the production facility, there is a small cost included associated with compressing the hydrogen up to 350 bar into the tube trailer.

6.2 DETAILED RESULTS FOR TOP-RANKED REGIONS

Rank	Hub location	Total weighted demand in 2050 (tpd)	Total potential demand in 2050 (tpd)	Last-mile distribution option		Mode breakdown by demand (%)			
				Direct connection demand (tpd)	Tube trailer demand (tpd)	HGV	Bus	Rail	Aviation
1	London	30	109	6	103	17	23	38	22
2	Yorkshire	25	71	9	62	29	15	56	0
3	Manchester	22	60	6	54	21	13	66	0
4	Birmingham	20	78	9	69	28	22	50	0
5	South West	14	40	15	25	8	8	84	0