Hydrogen Infrastructure Spatio-Temporal Optimisation for the UK's Heat Network

Hassan Sherbaz, Klement Tam

Abstract

Heating for residential and industrial buildings releases 110Mt of CO_2 annually. 85% of heating comes from natural gas, which is not compatible with the Committee on Climate Change's proposed target of net zero greenhouse gas emissions by 2050. Hydrogen can be a low-carbon replacement to natural gas due to it's storage flexibility and minimal transmission losses. To identify the key opportunities and challenges in a hydrogen-for-heat network, the Hydrogen Infrastructure Spatio-Temporal Optimisation (HISTO) model was developed. This illustrates a gradual transition from natural gas to hydrogen from 2020 to 2050. HISTO also studies the intraday and interseasonal demand fluctuations. A Pareto frontier was developed between the Total Discounted Cost against an Emission Budget Target by 2050. Each data point provides a spatio-temporal optimisation of the UK grid. Different scenarios were studied. This highlighted that using a 20mol% blend of hydrogen with methane would provide a minimum of 16% emission cut, without the need for appliance or transmission overhaul, providing a "low-regret" solution for 2030. Underground storage was also imperative as they provided a guarantee of supply even if there was a large reliance on intermittent sources of production i.e. wind and electrolysers. Finally, allowing the wind generators to sell electricity to the grid and the electrolysers enhanced the uptake of electrolysers, therefore some integration of the heat and electricity grid can be economical. Such results can be used to better inform policy makers, local authorities, utility providers and investors.

Keywords - Spatio-Temporal, Hydrogen for heat, MILP, Supply chain optimisation

1. Introduction

In a typical year, the UK consumes 328TWh of heat energy with a peak demand of 159GW [1]. This results in 110Mt of CO_2 emissions, 30% of the total annual emissions. 85% of this heating is supplied from natural gas, which emits 0.184 kg CO_2/kWh [2]. Currently, 56% of the natural gas supply for electricity generation and heating is imported, most of which is via European pipelines from Russia. As North Sea gas fields start to deplete, dependence on imports for natural gas will increase, thus increasing political dependence to meet energy requirements. Despite this, household consumption of electricity and heat has fallen by 17% in the last decade due to enhancements in building efficiency and insulation which is significant considering the number of households has increased. The Committee on Climate Change (CCC) published a report which replaces the 80% Greenhouse Gas (GHGs) reduction target by 2050, where they now propose a 100% reduction [3]. Consequently, radical action must be taken to tackle all emissions sources within the UK. This means that alternatives to natural gas for heating need to be implemented on a national scale within the next 30 years. The CCC has outlined several "low-regret" approaches which can be a feature in a number of different decarbonisation targets [4]. These include:

1) Continuing to improve energy efficiency in existing and new buildings
2) Low carbon heat networks in heat dense areas. This can be through heat recovery from Large Biomass, Municipal Waste, and other Industrial activities.
3) Heat pumps in the half of the 4 million homes not connected to the mains gas network

This, however, does not tackle the 20 million gas-heated homes in areas where heat networks are not cost effective. The decarbonisation strategies for such buildings include:

1) Electrification using highly efficient heat pumps and storage heaters for smaller properties.
2) Shifting to a green gas supply such as low-carbon hydrogen
3) Hybrid heat pumps where heat pumps meet most of the demand and hydrogen or a blend can meet the peaks.

Imperial College London was commissioned to provide a study on this which showed all three pathways had annual costs within 10% of each other [3]. This was in line with estimates by Element Energy Ltd . This suggests that for a complete decarbonisation, a combination of all 3 pathways could be deployed. Such costs also meet budgets of less than 1% GDP as proposed by CCC [4]. These findings show that to cut emissions, a low-carbon gas is necessary to deploy serious decarbonisation pathways. The main reasons for why hydrogen is being considered as a potential low-carbon gas are as follows:

1) Transmission losses are minimal relative to other technologies. For electricity, 9% is lost from production. District heat and hot water networks are even more inefficient and costly to transport over long distances. Consequently, hydrogen has the potential for centralised production, transportation, storage and local conversion to heat.
2) Hydrogen, like natural gas is easily stored. On the other hand, electrification of heat would not provide the same flexibility due to the limitations of electric batteries. Currently, batteries would incur large losses if they were used to meet interseasonal demand and are also too small in scale. Direct thermal storage for long periods is also difficult due the required insulation of the storage device.

This is too expensive to consider as a national-scale solution.

Because of this, hydrogen is being considered seriously as a low-carbon gas. Detailed planning is required to inform investors and policymakers as well as to set up pilot projects. This is because several challenges currently exist for hydrogen-for-heating. The main production methods for hydrogen are electrolysis, methane reforming and gasification (Coal or Biomass). For electrolysis, the electricity supplied must come from renewable sources such as wind to ensure that zero-carbon hydrogen is produced. Wind is an intermittent source of electricity, which means the production is not guaranteed. Methane reforming produces CO_2 and hydrogen, which therefore requires Carbon Capture and Storage (CCS). Similarly, gasification produces CO_2 and requires CCS. Ultimately, this raises the problem of which production facilities to use, and in which locations considering varying demand, underground formation for storage, and area availability.

2. Literature Review

Commissioned industry reports provide a good basis to define the problem. Several models have been built to analyse the feasibility of adopting hydrogen as a fuel. Equilibrium energy models such as MARKAL/TIMES match supply and demand over a given planning period [5]. However, this does not include any spatial resolution, and interseasonal and intraday supply and demand. Supply chain models for hydrogen have been developed in the context of the mobility sector and can provide more in-depth insights. Such models can still be adapted for a hydrogen for heating supply chain model.

2.1. Commissioned Reports

One of the key strategies in the *Decarbonisation of Heat* report [6] is providing a low-carbon solution for buildings that are on the gas grid and not on heat networks. This constitutes most of the current heat demand. The *Next Steps on UK Heat policy* report [3], recommended that the 20 million homes currently connected to the central natural gas grid could be decarbonised by using hydrogen.

Consequently, there has been a greater initiative to test the feasibility of using hydrogen since 2016. The BEIS hydrogen supply chain evidence base [7] provides a basis for the hydrogen production technologies with their associated costs and learning rates up to 2050.

The H21 report [8] provided a localised study of Leeds' heating supply and found that by leveraging the existing network, a natural gas to hydrogen conversion is feasible. The end result showed that 4 steam methane reformers were constructed with a total capacity of 1025 MW_{HHV}, with interseasonal and intraday demand balanced using salt caverns in Teesside.

In terms of live pilot projects, HyDeploy [9] started a live test in Keele University (Phase 1) where a 20mol% hydrogen blend with natural gas is being tested for heating. This has now been proven to be safe without the need to replace pipelines or boilers. Phase 2 and 3 will see a wider gas blend roll out to different residential properties in the North East. The hydrogen is being produced using electrolysis. Meanwhile in the North West, HyNet is looking to produce hydrogen through Auto-Thermal Reformers (ATRs) whilst capturing the CO_2 and storing it in Liverpool Bay's oil and gas fields. The aim is to build 890 MW of hydrogen output capacity from ATRs with a 93% CO_2 capture rate, where the hydrogen can be injected to the Local Transmission Network (LTS). However, the *Element Energy Ltd* report [7] states that current ATR designs are more suited to Syngas production and must be re-optimised for pure hydrogen production. For that reason, previous modelling work has focused on using SMRs as it is a more established design.

2.2. Mobility Sector Spatial Optimisation

Much of the early research in hydrogen supply chain optimisation was focused on the mobility sector. One of the first models which applied spatial optimisation was the Almansoori model [10]. It developed a future hydrogen supply chain for fuel cells in the mobility sector within the UK. The model divided the UK into 34 spatial zones where hydrogen can be transferred via road tankers to fuelling stations.

Several modifications have built on top of this spatial formulation. Moreno added constraints that consider carbon (for CCS) and hydrogen pipelines for distribution across the UK [11]. Dayhim applied a demand forecast on New Jersey by analysing how uncertainty in socio-economic factors affected this network [12]. Kim and Moon considered safety as well as profit, and allowed for hydrogen production through wind turbines with electrolysers [13]. Sabio's model took a holistic view of minimising emissions by carrying out a full Life Cycle Assessment [14].

The main drawback of these models is that they are "snapshot" models, i.e. only the spatial optimisation of the network are considered at a single point in time. The interseasonal and intraday demand shifts were not accounted for, prohibiting a comprehensive modelling of operating an energy network. Storage is often considered as a static parameter expressed as a certain number of days of demand stored, e.g. 10 or 20 days. This level of analysis will not exemplify the benefits of storing and transmitting hydrogen at different times of the year and day, especially when it is produced through variable renewable sources. Except Kim and Moon, all the models discussed do not consider wind generation to produce hydrogen. The Kim and Moon paper takes a static average production rate which underestimates the intermittency challenges of relying on renewable resources.

2.3. Spatio-Temporal Optimisation

Newer models achieved more comprehensive studies of potential hydrogen supply chains by adding a time-dependent element.

Lahnaoiu developed a model optimisation on North Rhine-Westphalia, Germany, where hydrogen is produced from excess wind electricity [15]. This was applied to the mobility sector, where optimal truck paths to the fuelling stations were identified.

Reus's model highlighted the challenges of matching intermittent supply of hydrogen through wind and the varying demand of in Germany's mobility sector [16]. It provided a detailed study of seasonal storage and performed wind turbine site suitability modelling using Geographic Information System (GIS) software.

Samsatli's Value Web Model (VWM) took a focused view on hydrogen-for-heating in the UK [17]. Similar to Reus, it utilised GIS modelling to assist in the planning of building new wind turbines. The model studied a combined network situation where heat and electricity grids are integrated which will provide added synergies and a smarter network. However, the end recommendation of using 80% electric heating and 20% hydrogen for heating might be more difficult in practice. The heating demand peaks are 5 times greater than the electricity peaks, adding 300GW [6]. This will require significant reinforcement to the electricity grid and such associated costs are not considered in the VWM. Consequently, an 80% direct electric heating future contradicts the commissioned reports discussed above.

2.4. Contributions Of Work

The discrepancy between the commissioned reports analysing UK's heating demands and current spatio-temporal models remains significant. This work aims to provide insights which can bridge this gap further and better inform policy makers and investors. In particular, none of the previous models considered a gradual transition over time from the current predominantly-used natural gas to a future hydrogen infrastructure network, specifically for the heating industry. By building a novel spatio-temporal optimisation model for a hydrogen supply chain without reliance of an extensive integration with the electricity grid, it will provide a stand-alone study for how this transition can occur. This model can then be further modified accordingly to test potential real cases of hydrogen deployment such as using blends, wind outages and minimal grid integration.

3. Methods

3.1. Spatio-Temporal Optimisation

In this study, UK is spatially distributed into 12 zones based on the regions which the Department for Business, Energy and Industrial Strategy (BEIS) collects its gas consumption statistics. Temporal representations are important to monitor network movements across the 30-year horizon from 2020 to 2050. 5-year planning period intervals are considered for investment decisions. Each planning period interval comprises the 4 seasons (Winter, Spring, Autumn, and Summer) and each season consist of 4 times of the day (Day, Evening Peak, Late Evening, Night). Altogether, these form 16 non-uniform time slices per 5-year planning period.

3.2. Infrastructure Network

Fig. 1 depicts the hydrogen infrastructure network diagram across the three components of the supply chain considered – production, storage and transmission. Hydrogen can be generated within the zone either by steam methane reforming with 90% carbon capture storage (SMRCCS), onshore wind turbines with proton exchange membrane electrolysers (ONWTE), or by offshore wind turbines with PEM electrolysers in the waters for coastal zones (OFFWTE). It is assumed that the wind turbine and electrolyser are built in the same zone. The produced hydrogen can then be stored in underground salt caverns (if present in the zone) or pressurised vessels which can be built in 3 different sizes. Transmission within neighbouring zones is viable through pipelines or trucks. Together with the natural gas network assumed to be already present in all zones, the hydrogen generated in a zone or received from other zones, can then be used to satisfy local heat demands.

The technologies chosen for this study are those that have been well supported by previous work on hydrogen supply chain and are financially practical. For example, PEM electrolysers were favoured since it has been scientifically tested and has a higher learning rate on capital cost than the more mature alkaline electrolysers [7]. Other technologies such as gasification techniques were not considered as the design is still in the early stages for pure hydrogen production and has excessive predicted costs.

3.3. Hydrogen Infrastructure Spatio-Temporal Optimisation Model (HISTO) Mathematical Formulations

The novel Hydrogen Infrastructure Spatio-Temporal Optimisation model (HISTO) is a mixed-integer linear program (MILP). Optimal solutions for the investment and operation of the hydrogen supply chain infrastructure (including transmission and managing of storage inventory) were found by implementing the proposed algorithm using the CPLEX solver accessed via the GAMS modelling tool. The nomenclature and complete set of formulations are found in the Supplementary Material.

3.3.1. Material balance: The flows across production, transmission and storage in each zone and time slice are represented by the material balance in Eq. (1), which is an inequality constraint that balances these flows. The demand for each zone, is obtained from current gas consumption statistics for 12 zones in the UK [18]. Allocated demand for residential and industrial properties are aggregated then split into 16 time slices. The total heat demand was converted by assuming a natural gas boiler efficiency of 80%. Hydrogen boiler efficiency was assumed at 90% [19]. A conservative assumption was made that the annual heating demand will remain the same as there could be a trade-off between improved building efficiency and more buildings constructed.

$$\begin{aligned}\textstyle\sum_{z't}(QT_{zz'tyh} - QT_{zz'tyh}) + \sum_{s}(QSout_{zsyh} - QSin_{zsyh}) \\ + \textstyle\sum_{p} PRD_{zpyh} - Demand_{zh} = 0, \forall z, y, h\end{aligned} \tag{1}$$

3.3.2. Production: The hydrogen production rate in each zone and time slice is bounded by the installed capacity of production technologies in the zone, which can increase across planning periods as seen in Eqs. (2) and (3). A production

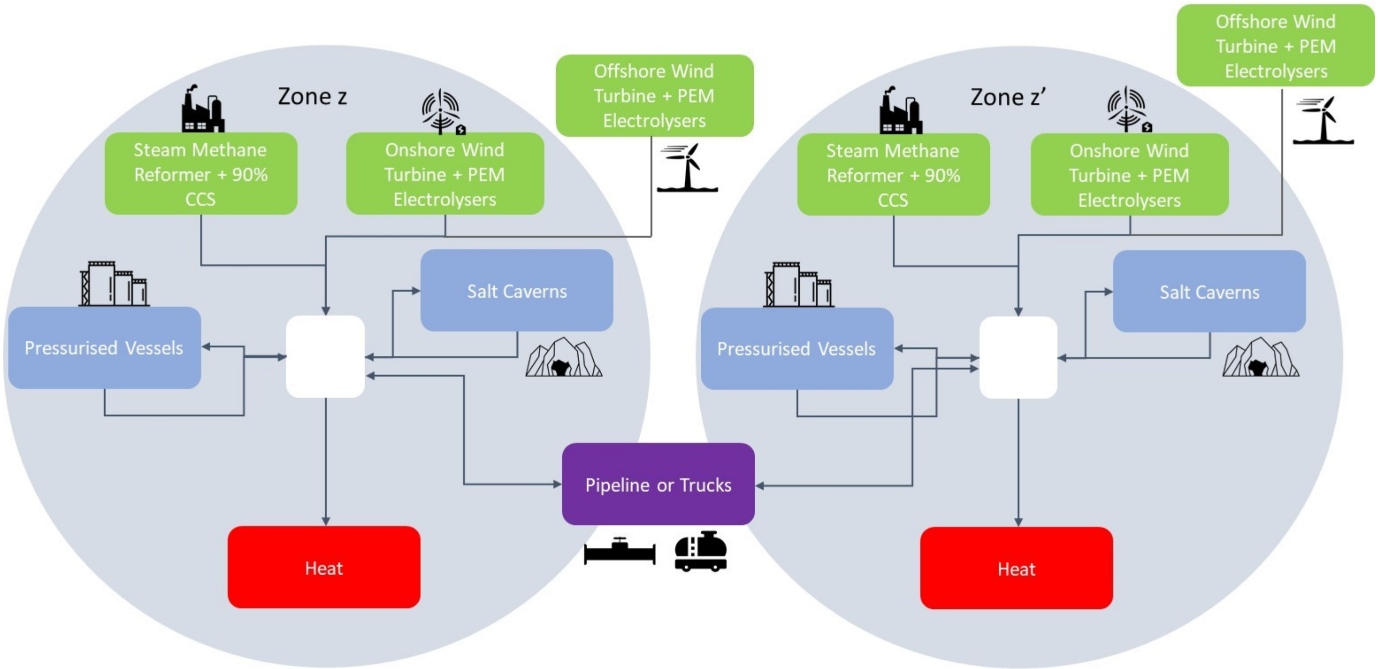

Fig. 1: Hydrogen infrastructure network diagram showing all potential supply chain pathways

factor is included in Eq. (2), which accounts for the varying wind speed profiles in different seasons and times of the day as obtained from Sinden (2007) [20]. Since installing onshore wind farms may spark concerns on land availability, the number of new onshore wind turbines installed in each zone are restricted using Eq. (5). The factor $2\sqrt{3}$ assumes that the turbines are arranged on a hexagonal grid. Data for the total available area for wind turbines in each zone are adapted from Samsatli et al. (2016) [21] which used GIS mapping.

$$Producemin_p \cdot PRDFactor_{ph} \cdot PRDCAP_{pzy} \leq PRD_{pzyh} \leq PRDFactor_{ph} \cdot PRDCAP_{pzy}, \forall z, p, y, h \tag{2}$$

$$PRDCAP_{pzy} = PRDCAP_{pzy-1} + PRDCAPI_{pzy}, \forall z, p, y \geq 2 \tag{3}$$

$$PCAP_p^{min} \cdot NPI_{pzy} \leq PRDCAPI_{pzy} \leq PCAP_p^{max} \cdot NPI_{pzy}, \forall z, p, y \tag{4}$$

$$\sum_y 2\sqrt{3}(5R^w)^2 \cdot NPI_{pzy} \leq PCAP_p^{max} \cdot NPI_{pzy}, \forall z, p = ONWTE \tag{5}$$

3.3.3. Storage: A material balance is used in Eq. (6) for the amount of hydrogen that is stored between timeslices. The stored amount is constrained by the storage capacity in Eq. (7) which similar to production, can increase every planning period for that of pressurised vessels. Binary variables in Eqs. (8) – (10) enforces that hydrogen is either added or removed from the storage facility in each timeslice and not both simultaneously. Flowrates into and out of storage facilities are also bounded by maximum deliverability and injection rates.

$$Store_{szyh} = Store_{szy,h-1} + (QSin_{szy,h-1} - QSout_{szy,h-1}) \cdot Duration_h, \forall z, s, y, h \geq 2 \tag{6}$$

$$Store_{szyh} \leq STRCAP_{s,z,y}, \forall z, s, y, h \tag{7}$$

$$SIN_{szyh} + SOUT_{szyh} \leq 1, \forall z, s, y, h \tag{8}$$

$$\frac{SIN_{szyh}}{M_a} \leq QSin_{szyh} \leq SIN_{szyh} \cdot MaxInj_{sz}, \forall z, s, y, h \tag{9}$$

$$\frac{SOUT_{szyh}}{M_a} \leq QSout_{szyh} \leq SOUT_{szyh} \cdot MaxDel_{sz}, \forall z, s, y, h \tag{10}$$

3.3.4. Transmission: Hydrogen can be transmitted between zones via pipelines or trucks. Eq. (11) - (12) ensures unidirectional pipeline flow between 2 zones. The big-M method was used in Eq. (12) to determine whether there is hydrogen flow between 2 zones. In Eq. (13), pipeline flows are bounded by the total pipeline capacity, which is attained from assuming a constant pipeline diameter of 10 inches. Eq. (14) allows for additional pipelines to be built in each planning period.

$$X_{zz'yh} + X_{z'zyh} \leq 1, \forall z, z', y, h \tag{11}$$

$$\frac{X_{zz'yh}}{M_a} \leq QT^{pipe}_{zz'yh} \leq X_{zz'yh} \cdot M_a, \forall z, z', y, h \tag{12}$$

$$QT^{pipe}_{zz'yh} \leq NT^{pipe}_{zz'y} \cdot QTCAP^{pipe}_{zz'}, \forall z, z', y, h \tag{13}$$

$$NT^{pipe}_{zz'y} = NT^{pipe}_{zz',y-1} + NTI^{pipe}_{zz'y}, \forall z, z', y \geq 2 \tag{14}$$

Eq. (15) calculates the flowrate transmitted via trucks, taking into account factors such as loading and unloading time, average truck speed, road distances etc. Eq. (16) bounds the amount of hydrogen transported while Eq. (17) allows additional truck units.

$$QT^{truck}_{zz'yh} = \frac{TruckOpTime}{\frac{2RoadDistance_{zz'}}{TruckAvgSpeed} + LUTime} \cdot \frac{VT^{Truck}_{zz'yh}}{Duration_h}, \quad \forall z, z', y, h \tag{15}$$

$$0 \leq \sum_{z'} VT^{Truck}_{zz'yh} \leq NT^{truck}_{zy} \cdot QTCAP^{truck}, \forall z, y, h \tag{16}$$

$$NT^{truck}_{zy} = NT^{truck}_{z,y-1} + NTI^{truck}_{zy}, \forall z, y \geq 2 \tag{17}$$

3.3.5. Emission budget: The final category of constraints includes the emission budget constraint. As seen from Eq. (18), an inequality constraint is placed on the amount of CO_2 that can be emitted from the production technologies across the network. The right side of the equation shows the parameter EBT, which is a set emission budget target at 2050, i.e. a proportion of current emissions from natural gas that is allowed. A linear decrease of the permissible emissions is assumed over the planning periods (2020-2050) to achieve this set carbon emission budget target.

$$\sum_{p,z,h} CO_2Emission_p \cdot PRD_{zpyh} \cdot Duration_h \leq CurrentEmission \cdot EBT \cdot \frac{y - 2015}{35}, \forall y \tag{18}$$

3.3.6. Objective function: The objective function minimizes the total discounted costs, which takes into account the investments and costs of operation of the entire hydrogen network in each planning period. The costs and learning rates for production, storage and transmission were obtained from the Element Energy Ltd, and the H21 reports [22], [8].

$$\min_{s.t.} TDC = \sum_y \frac{TC_y}{(1+r)^{y-1}}, \ where \tag{19}$$

$$TC_y = CAPEXP_y + OPEXP_y + CAPEXS_y + OPEXS_y + CAPEXT_y + OPEXT_y \tag{20}$$

4. RESULTS AND DISCUSSION

The model was implemented for a base scenario which examines a bi-criterion optimisation approach in the design and planning of the hydrogen network. In addition, the optimisation model was configured for 3 case studies which provides further depth into the proposal of using a hydrogen network for heating. The base case and case studies are as follows:

- Base case - examining how TDC varies as the EBT parameter is tightened, and probing into the optimised spatio-temporal solution across the supply chain for a specific EBT.
- Case 1 - investigating how a live pilot project, in particular HyDeploy, would work on a large scale across the entire UK.
- Case 2 - exploring the impacts of wind outages in deep decarbonisation scenarios, where there is a high adoption of wind turbines with electrolysers.
- Case 3 - analysing how selling part of the wind turbine installed capacity to the electricity grid can affect adoption of electrolysers.

All the MILP problems were implemented in GAMS and solved using the CPLEX solver on a High Performance Computer. For each EBT, the simulation consists of 149,666 variables (of which 33,972 are integer variables) and 178,606 constraints. The total CPU time taken varied across different scenarios, with the longest (EBT = 0.1) taking 21 minutes. An optimality tolerance of 0.1% was chosen (i.e. the best integer objective must be within 0.1% of the objective of a fully-relaxed problem) to ensure a sufficient level of accuracy.

4.1. Base Scenario

4.1.1. Pareto solution: By introducing a *LOOP* function, the MILP optimisation problem was solved multiple times, with each consecutive iteration having a different EBT and thus different allowable emissions in the same planning period. This generated a Pareto frontier as shown in Fig. (2), illustrating the trade-off between TDC and EBT. Fig. (3) shows the accumulated total heating energy supplied from 2020-2050 with different values of EBT.

The frontier can be segmented into 4 categories: A) A complete natural gas grid when there is no limit on carbon emissions; B) Linear uptake of SMRCCS due to its steady adoption against natural gas; C) Emergence and uptake of ONWTE as the EBT becomes too tight for SMRCCS to exist as the only hydrogen production technology; D) When ONWTE exists as the only hydrogen production technology for complete decarbonisation by 2050.

ONWTE only emerges when the EBT is under 0.2 due to its higher costs (driven by electrolysers) relative to SMRCCS, despite the former having a more favourable learning rate on capital costs. Consequently, a steep increase in TDC is incurred as more ONWTE is adopted, making deep depcarbonisation scenarios less financially feasible. The most expensive option of OFFWTE is not adopted throughout, which shows that there would be sufficient area for onshore wind turbines if a hydrogen network were to be implemented.

It is worth noting that if ATRs were considered, they would replace all SMRs as they allow for a higher capture rate (95%) at a similar costs. However, they were not included as functional designs optimal for hydrogen production are not as mature as SMRs [7].

4.1.2. Model validation: To achieve complete decarbonisation, i.e. EBT of 0, this incurs an additional £15.6bn relative to point A on Fig. (2). This amounts to a cost of avoided emissions of £56.5/tCO_2 saved and a levelised cost of heat (LCOH) of £58.1/MWh.

The Value Web Model predicts that for a 82.6Mt CO_2 annual saving, it would cost £8.54/tCO_2 with a LCOH of £38.28/MWh (current nominal heat price £33.3/MWh) [23]. The HISTO model requires a much more expensive cost of emission avoidance £39.5/tCO_2 and a LCOH £45.5/MWh . On the other hand, the H21 report states that the 4 SMRCCS units for Leeds would require £291.4/tCO_2 for emission avoidance [8]. As the scale of the HISTO model is much greater than the H21 study, a more connected network would provide cost savings not found in a localised study. However, the H21 reports provides greater granularity in the cost structure, which makes it more conservative than the HISTO model. On the contrary, the VWM allows for 80% of heating to be electrified, saving costs on SMRs and PEM electrolysers whilst not considering the cost of electric grid reinforcement required. Consequently, the VWM could potentially be underestimating the feasibility of its optimal solution.

A technology abatement curve done by McKinsey includes several technologies which would cost below £50.5/tCO_2. Similar to the HISTO model, it calculates the abatement rates assuming aggressive uptake of a particular technology. Currently, complete decarbonisation in the HISTO model exceeds this by £6/ tCO2. Despite this, EBT = 0.1 has comparable abatement costs to other technologies such as Gas and Coal plant CCS retrofit [24].

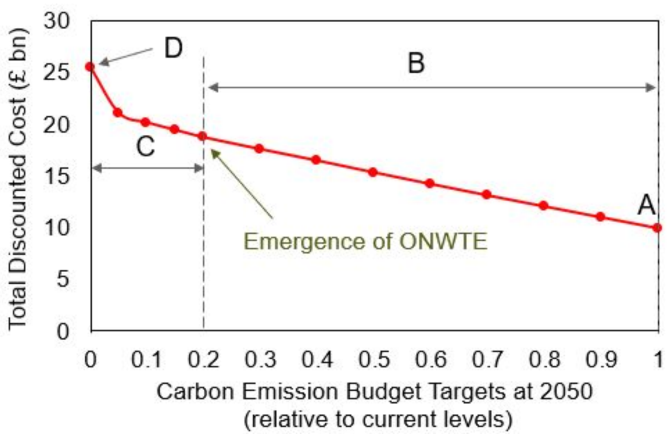

Fig. 2: Pareto solution of TDC against EBT

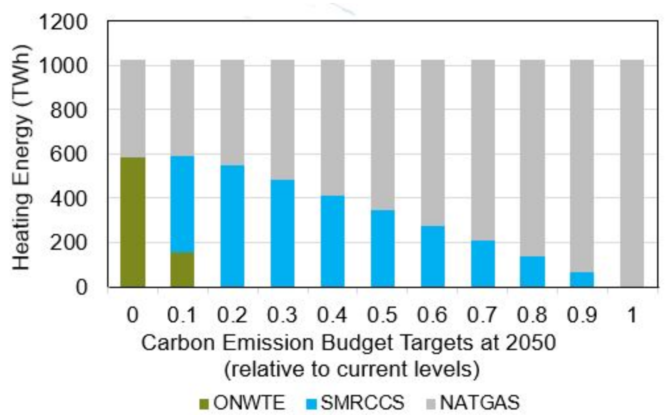

Fig. 3: Total heating energy supplied from 2020 to 2050

4.1.3. Hydrogen network transition: Fig. (4) dives into the hydrogen network transition over the time horizon when the EBT is set at 0.1. This has an LCOH of £48.6/MWh which is a 46% increase from the current nominal price. This would have to be subsidised by the government, but the end customers will also face a large increase. Only 3 planning periods are shown. The complete network over time can be found in the Supplementary Material. In the first planning period (not shown here), the model builds SMRCCS in all zones except for Z7 and Z8 (Inner and Outer London), which has been prohibited due to limitations of major industrial activities in the capital. As time progresses towards 2030, more SMRCCS units are installed. Zones with underground salt caverns (Z2, Z3, Z9) are key locations for hydrogen production units.

As seen from Fig. (4a), the pipeline network shows a disconnect between North and South England until 2035. As the transition from natural gas to hydrogen extends due to emission constraints, the salt caverns' capacity in Z9 is not large enough to provide the flexibility in surrounding regions (Z7, Z8, Z9 and Z10). Thus, the 2 pipelines connecting Z4 with Z6 and Z6 with Z8 introduced in Fig. (4b) are crucial to enable the Southern zones to have access to the much larger salt caverns in Z3 (Yorkshire). By 2035, the hydrogen pipeline network connects all the zones accordingly.

From 2040 onwards, the emission budget becomes too small for only SMRCCS to be built, explaining the large uptake of ONWTE. The final network in 2050 is shown in Fig. (4c), where 52% of heating comes from ONWTE distributed across UK depending on area and wind availability of each zone.

4.1.4. Interseasonal storage: No pressurised vessels are installed throughout the years, which demonstrates the high costs of the technology. However, underground salt caverns play a huge role in the hydrogen network. Fig. (5) displays the optimal storage inventory over a typical year. In all the 3 zones with salt caverns, hydrogen is accumulated in the summer to reach maximum capacity in autumn, before distributed to the surrounding zones during winter to fulfill the higher heating demands.

4.1.5. Intraday storage: Fig. (6) shows the total net flow into all storage units at different times of the day during the 4 seasons. During spring, there is a varied flow of hydrogen at different times of the day. A positive net flow into storage units is seen throughout the summer time slices, explaining the steep accumulation of hydrogen inventory in Fig. (5). Storage inventory movements are relatively neutral during autumn. Key periods during winter include the day (07:00h-17:00h) and evening peaks (17:00h-20:00h), where the high demand requires a large outflow of hydrogen from the storage units.

4.2. Case 1 - HyDeploy

HyDeploy is a pilot scale project testing the feasibility and safety of using a 20mol% hydrogen blend with natural gas. Phase 1 became live in Autumn 2019 where the blend was used to heat Keele University. It is expected that Phase 2 and 3 will lead to supplying heat for residential homes in the North East area. The significance of this blend is that it does not require appliance or pipeline overhaul. The existing infrastructure can be utilised. Consequently, the base model was augmented to analyse the emission cut, TDC and the optimal network which can be achieved if such a blend was used on a national scale. One of the safety issues associated with using a blend is that hydrogen's flammability limits are wide (between 4 vol% to 75 vol%). This is why the HyDeploy project is testing a wide variety of end user scenarios in Phase 2 and 3.

Fig. (7) illustrates that a 16% emission cut can be achieved with a 20mol% hydrogen blend. The optimised solution will

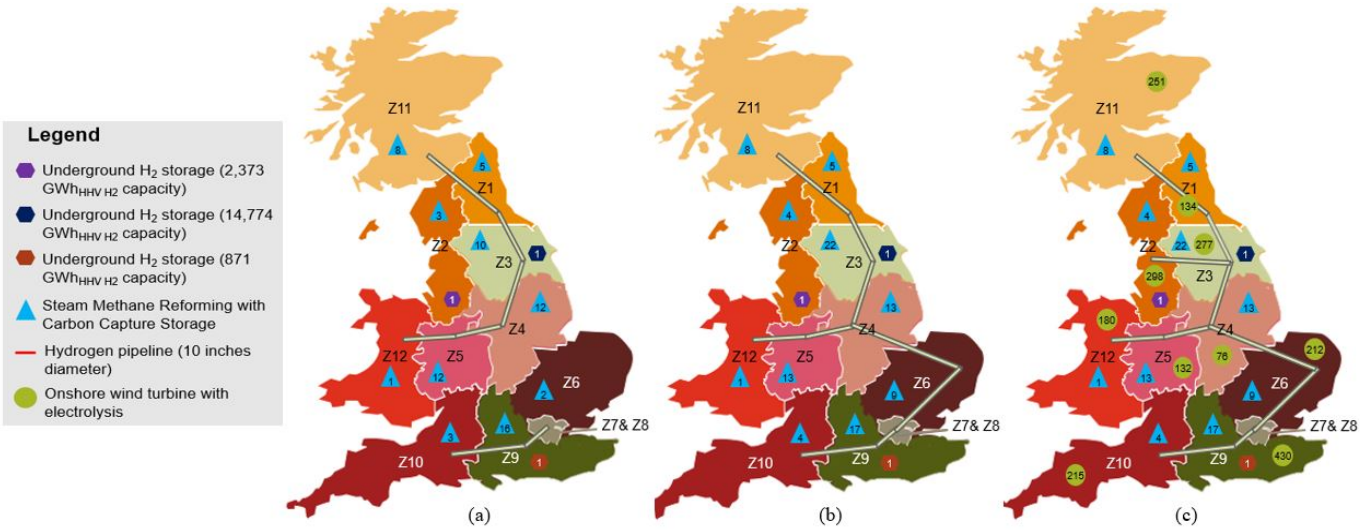

Fig. 4: Optimal hydrogen infrastructure network in the base case for 0.1 EBT: (a) 2030; (b) 2035; (c) 2050

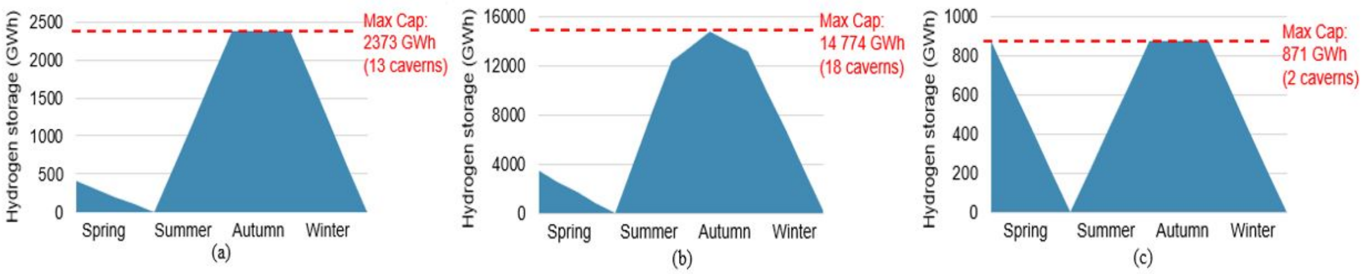

Fig. 5: Optimal hydrogen inventory in salt caverns over a typical year: (a) Cheshire underground storage in Zone 2; (b) Yorkshire underground storage in Zone 3; (c) Weald underground storage in Zone 9

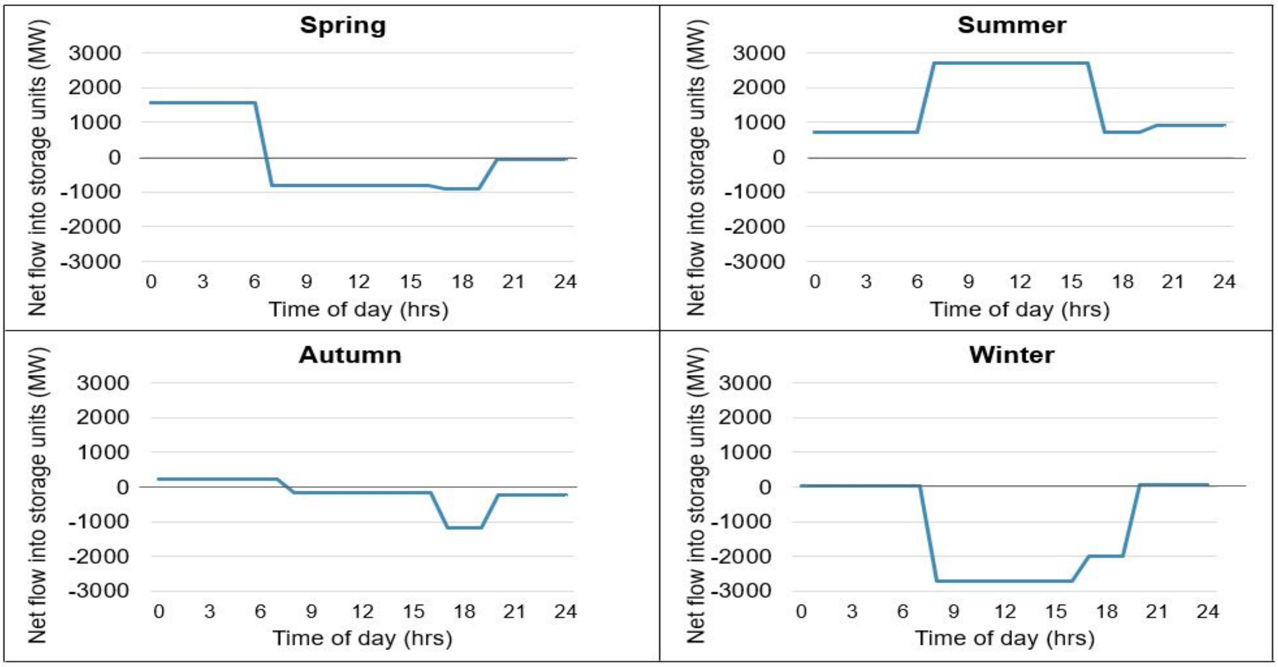

Fig. 6: Intraday storage - optimal operation of hydrogen storage inventory flows for each season

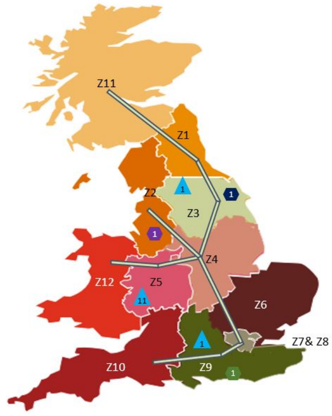

Fig. 7: Optimised spatial network for a 20mol% hydrogen gas blend at 2050

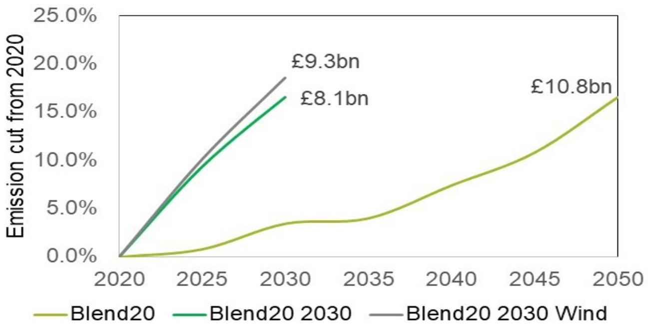

Fig. 8: Methane and Hydrogen blends cutting emission over time. Each scenario incurs a different TDC

build 11 SMRCCS units, concentrated at the centre of the country (Z5), and will invest in the pipeline network to distribute to all the zones. However, a 16% emission cut by 2050 will leave the UK far from meeting the CCC net zero GHG target. As a result of this, the model was altered to achieve this by 2030, which would result in a lower TDC of £8.1bn, as seen from Fig. (8). However, HyDeploy is currently using electrolysis to produce the hydrogen and a major assumption of the model is that CCS will be feasible before 2030. Thus, a third run which prohibited the use of SMRCCS before 2030 was executed, which resulted in a TDC of £9.3bn. This is a significant increase but it is a more realistic outcome. Overall, if HyDeploy's test are successful, a "low-regret" solution would be to scale up the 20mol% hydrogen blend with ONWTE using PEM electrolysers to achieve an 18% emission cut by 2030. This would lead to an additional cost of £38.4/tCO_2 saved. This falls cheaper than new build coal CCS on McKinsey's abatement curve [24]. It would have an LCOH of £37.4/MWh which is only a 12% increase from the nominal price.

4.3. *Case 2 - Wind Outage*

In order to decarbonise more than 80% of the heat demand, wind turbines with electrolysers must play a key role in the hydrogen network. However, the main concern faced by wind energy is the unpredictability in weather. Thus, an extreme case of an extended period with no wind was modelled. This period was chosen to be in the summer time slices (when wind speeds tend to be lower) of 2045 (when ONWTE already has a high adoption in the hydrogen network). The model was augmented by setting $PRDFACTOR_{ph}$ as zero for $p =$ ONWTE, OFFWTE during the summer time slices.

Fig. (9) displays the impact this would have on hydrogen inventory levels. Unlike before, storage does not build up during the summer since there is no production from wind turbines. The loss is offset from 2 factors - accumulation of storage in the spring season beforehand and increased production from SMRCCS during the summer itself. After the extended period with no wind, ONWTE would increase production (close to its maximum capacity) to bring hydrogen inventory back to that of the levels experienced in base case. This allows the EBT to still be met. Therefore, the key interpretation to be drawn from this case is that hydrogen storage is not only essential to meet demand fluctuations, but also to react to potential inconsistencies in wind speeds. This can also provide certainty in commercial contracts for utility providers, local authorities and investors as a known amount of hydogen supply can be guaranteed through storage.

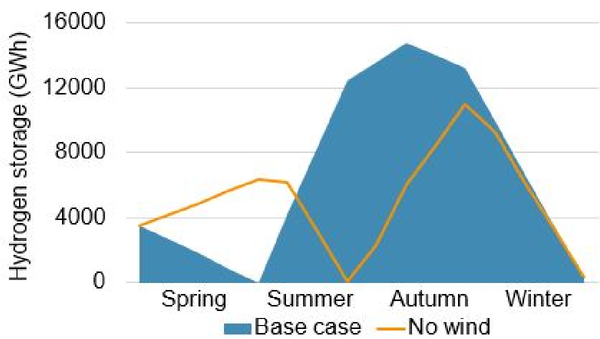

Fig. 9: Optimal hydrogen inventory in Yorkshire salt caverns (Zone 3) for base case and case with extended period of no wind during the summer of the 2045 planning period interval

4.4. *Case 3 - Grid Integration*

Since ONWTE would not produce up to its installed capacity at periods of lower heating demand, this case study examines the option of allowing a fraction of the wind turbine's installed capacity to be used in selling electricity to the grid. This can further incentivise the uptake of ONWTE, which was a challenge in the base case due to its higher costs relative to SMRCCS. Fig. (10) displays a significant reduction in TDC for deep decarbonisation scenarios (when EBT is less than 0.2). Naturally, the percentage of the wind turbine's installed capacity sold into the electricity grid would be limited by the demand, but this can be considered in advance when forming the generation contracts. As a result, Fig. (11) shows that when more wind capacity is sold into the grid, the earlier ONWTE appears in the transition to the hydrogen network (2025). For a 7% wind capacity sold back into the grid, it would cost £40.4/tCO_2 with LCOH £50.8/MWh for complete decarbonisation (EBT=0), much lower than the base case (£56.5/tCO_2 and £58.1/MWh).

A top down policy could encourage the construction of ONWTE units. This can be done by registering the onshore wind turbines on the Balancing Mechanism and contracting a certain amount of energy to be supplied to the electricity grid. In addition to this, there is currently 1.5TWh/year of wind energy which is curtailed [25]. This can be utilised as cheaper electricity from existing wind turbine to feed PEM electrolysers. Such combination and smart control can maximise the synergies between the heat and electricity grid, without adding large loads on to the electric grid.

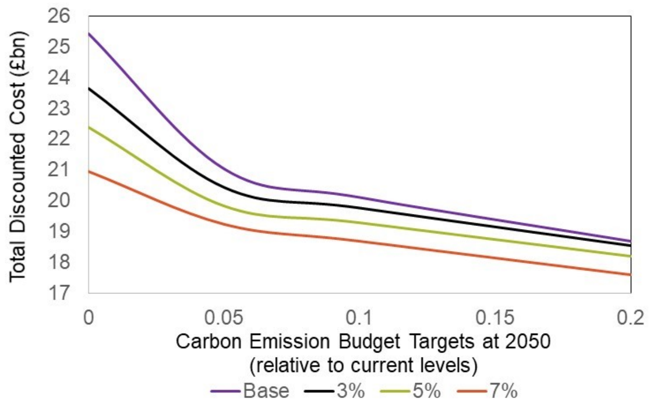

Fig. 10: Pareto solutions for deep decarbonisation scenarios, with different fractions of wind capacity sold to electricity grid

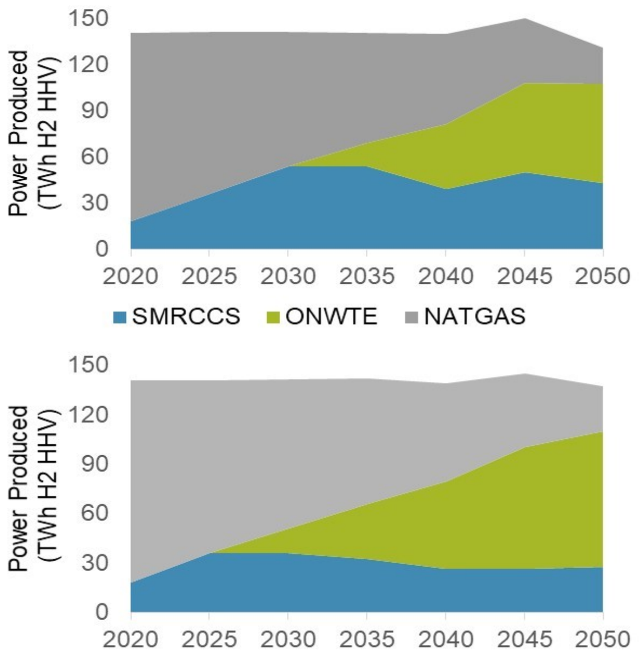

Fig. 11: Top: 3% of wind capacity sold, Bottom: 5% of wind capacity sold

4.5. Physical Constraints

In the base case and case studies generated by the HISTO model, SMRCCS is widely adopted. However, storage of CO_2 has not been achieved at a large scale yet. Currently, this is the largest underlying assumption which makes most of the transition scenarios feasible. Even if capture technologies, especially MEA absorption, are assumed to be feasible at large scale, the HISTO model does not consider the cost of transporting the captured CO_2 to underground formations and depleted oil and gas fields for long-term storage. By using a coarse grid, the HISTO model does not consider the associated appliance and transmission overhaul. In addition to this, there will be pressure differentials between the different levels of transmission which require compressors and expanders. This will create a further differentiation in feasibility especially when considering Case 1, since the 20mol% blend does not add such associated costs. The final output from the HISTO model relies on salt caverns for hydrogen storage. Whilst there are salt caverns around the world containing hydrogen, further safety testing is required on the UK salt caverns to ensure that capacities stated are all considered safe to provide similar load shifting flexibility as natural gas.

5. Conclusions

In this paper, the HISTO model was developed to explore a gradual transition from using natural gas to hydrogen for the provision of heat in the UK. The HISTO model comprises of a mixed-integer linear programming algorithm that provides the most cost-efficient method for designing a hydrogen infrastructure supply chain network to achieve a certain emission budget target at 2050. The model provides an optimal solution regarding the location and number of new hydrogen production, storage and transmission facilities installed across 5-year planning period intervals. In addition, the operation of the hydrogen network is resolved on an interseasonal and intraday basis.

Valuable insights can be attained from this study. As the heating demand becomes increasingly carbon constrained, there is a linear increase in TDC until EBT = 0.2. Below this target, there is an exponential increase in costs as ONWTE is adopted. The effectiveness of projects currently being piloted can be evaluated with the model. In particular, HyDeploy is a ”low-regret” solution which can be seen as a near-term strategy to remove at least 16% of the current annual CO_2 emissions within a decade. This will require a LCOH of £37.4/MWh which is a 12% increase from the current nominal price. However for deeper decarbonisation initiatives, ONWTE plays a key role in the hydrogen network. In these circumstances, underground salt caverns for hydrogen storage are crucial for balancing heat demand fluctuations at different seasons and times of the day, and alleviating the risk of wind speed unpredictability. Nevertheless, the cases have illustrated cost implications of using ONWTE. Thus, a suitable option would be to offset the costs by integrating a minor part of the heat grid with the electricity grid without overloading the latter. This can be done through careful planning and tools used by the National Grid.

The approach and results discussed in this study can benefit various stakeholders such as: (i) local planning authorities as insights into best locations and years for hydrogen technology deployment are provided; (ii) policy makers as live pilot projects and integration of heat and electric grids are evaluated; (iii) investors as they can filter out promising hydrogen technologies; (iv) research institutions that can accelerate experiments and trials on aspects like ensuring underground salt caverns are viable for hydrogen storage on a large scale.

If physical constraints as highlighted in the paper are overcome, a hydrogen-for-heat transition would be a viable course of action into a low-carbon future.

6. OUTLOOK

To enhance the detail of the HISTO model, CCS pipelines can be added as per Moreno's model [11]. The associated costs will alter the Pareto frontier and reduce uptake of SMRCCS. An additional case which can be further examined is a peak demand stress test, similar to the "Beast from the East" peak winter demand in 2018. For different residential and industrial properties, various potential strategies can be adopted as discussed in the Literature Review. By adding HISTO to a wider model that includes heat networks, improvements in building efficiency, heat pumps and hybrid pumps, a more detailed spatio-temporal transition analysis can be carried out.

Transportation of hydrogen is a problem due to its low density which makes it easy to leak. The HISTO model also showed that building pressurised vessels for hydrogen is expensive and will avoid doing this. As a result, the Commonwealth Scientific and Industrial Research Organisation (CSIRO) in Australia have launched a pilot project to convert hydrogen to ammonia which enables the use of existing infrastructure as well as liquid storage of ammonia [26] . If feasible, it can be added as an extension to the HISTO model.

In terms of model enhancements, using the demand and EBT parameters as a dual variable can provide the hydrogen price and carbon tax. This is complicated to attain for MILP problems but approximations for dual prices can be made.

7. SUPPLEMENTARY MATERIAL

Supplementary material associated with this paper can be found by clicking here.

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