Bay Hydrogen Hub – Hydrogen-4-Hanson

Department for Energy Security and Net Zero (DESNZ) Industrial Hydrogen Accelerator Stream 2A Feasibility Study

Public Report
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Glossary

Acronym	Definition
AACE	Association for the Advancement of Cost Engineering
ADR	Accord européen relatif au transport international des marchandises dangereuses par route (European Agreement concerning the International Carriage of Dangerous Goods by Road)
AMR	Advanced Modular Reactor
ATEX	Appareils destinés à être utilisés en ATmosphères EXplosives (Devices intended for use in EXplosive ATmospheres)
ATR	Autothermal Reforming
BAT	Best Available Technique
BEIS	Department for Business Energy and Industrial Strategy *(As of 7th February 2023 government department restructuring means BEIS no longer exists with DESNZ (see below) encompassing work related to this project)*
BoD	Basis of Design
BOP	Balance of Plant
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
COMAH	Control of Major Accident Hazards
COP	Cost of Produced Product
DESNZ	Department for Energy Security and Net Zero
DSEAR	Dangerous Substances and Explosive Atmospheres Regulations
EA	Environment Agency
EEP	Energy and Emissions Projections
EDF	Électricité de France
ESME	Energy System Modelling Environment (ETI Tool)
ETI	Energy Technologies Institute
ETS	Emissions Trading Scheme
FAT	Factory Acceptance Test
FOAK	First-of-a-kind
GGBS	Ground Granulated Blast Furnace Slag
GHR	Gas Heated Reformer
GVA	Gross Value Added
HAZID	Hazard Identification Study
HAZOP	Hazard and Operability Study
HBM	Hydrogen Business Model
HGV	Heavy Goods Vehicle
HHV	Higher Heating Value
HPC	Hinkley Point C
HVO	Hydrogenated Vegetable Oil
IHA	Industrial Hydrogen Accelerator
IMechE	Institution of Mechanical Engineers
JIT	Just-in-time

kWe/MWe/GWe	kilo/Mega/Giga watt Electric
kWh/MWh/GWh	kilo/Mega/Giga watt hour
kWth/MWth/GWth	kilo/Mega/Giga watt Thermal
LPG	Liquefied Petroleum Gas
LCHS	Low Carbon Hydrogen Standard
LCOA	Levelised Cost of Abatement
LCOH	Levelised Cost of Hydrogen
LHV	Lower Heating Value
MAPP	Major Accident Prevention Policy
MPA	Mineral Product Association
NCV	Net Calorific Value
NG	Natural Gas
NNL	National Nuclear Laboratory
NOAK	Next-of-a-kind
NOx	Nitrous Oxide
NPP	Nuclear Power Plant
NSIP	National Significant Infrastructure Project
NSSG	Nuclear Skills Strategy Group
NZIP	Net Zero Innovation Porfolio
OEM	Original Equipment Manufacturer
OPEX	Operational Expenditure
P&ID	Piping and Instrumentation Diagram
PBD	Pale Blue Dot
PEM	Proton Exchange Membrane / Polymer Electrolyte Membrane
PFD	Process Flow Diagram
PFO	Processed Fuel Oil
PLC	Programmable Logic Controller
plc	Public limited company
PPA	Power Purchase Agreement
PSSR	Pressure System Safety Regulations
RAB	Regulated Asset Base
R&D	Research and Development
RE	Renewable Energy
REGO	Renewable Energy Guarantees of Origin
SDGs	Sustainable Development Goals
SMR	Small Modular Reactor
SMR	Steam Methane Reforming
SOE	Solid-Oxide Electrolyser
SOEC	Solid-Oxide Electrolysis Cell
SSR	Station Safety Report
tpa	tonnes per annum
TPED	Transportable Pressure Equipment Directive

TRL	Technology Readiness Level
UKSAP	UK Storage Appraisal Project
UN	United Nations
WNN	World Nuclear News

1. Executive Summary

This end-to-end study has shown that it is feasible to decarbonise the asphalt industry and to support decarbonisation of the cement industry using hydrogen produced at a nuclear power station, using efficient MW scale Solid-Oxide Electrolysis Cell (SOEC) electrolysis technology, and distributing that hydrogen by high volume tanker to dispersed sites. The approach has potential benefits for other industries.

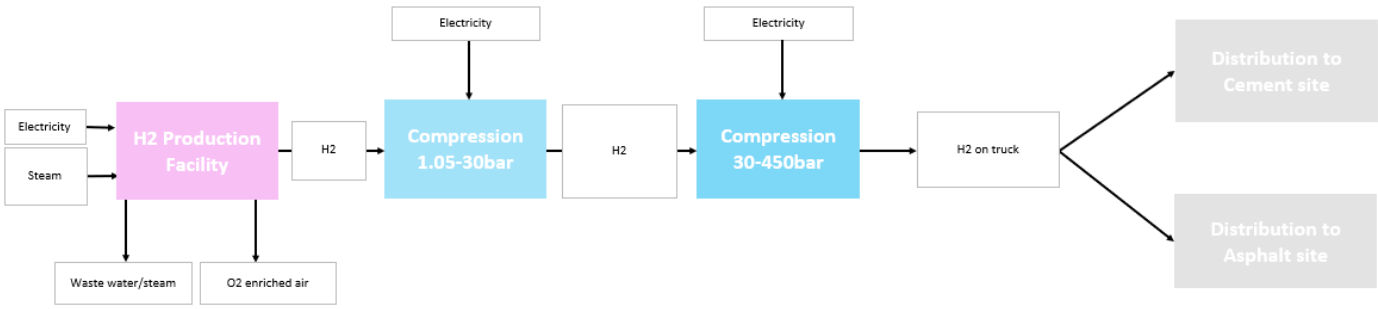

Figure 1 System diagram of hydrogen delivered to asphalt and cement sites

The study has met its objectives to:

- Assess the engineering and regulatory requirements for siting a Solid Oxide Electrolyser (SOE) at the Heysham 2 nuclear station, connecting to the auxiliary steam system and electrical utilities
- Develop an engineering design for hydrogen production and compression at the Heysham 2 site, capturing any challenges, limitations, and opportunities
- Investigate the engineering feasibility and economics of transporting hydrogen via high pressure composite tube trailers
- Develop an engineering design for converting an asphalt site to hydrogen, identifying equipment development challenges and site restrictions
- Produce a workable end-to-end solution that marries hydrogen production volume and timing with delivery options and end-use business as usual operations
- Investigate the future commercialisation and scalability of the production, distribution and end-use hydrogen technologies and applications.

Nuclear sites offer the perfect opportunity for coupling with SOE technology, with readily available low carbon heat in the form of process steam, low carbon electricity and on site de-mineralised water. The low-carbon hydrogen produced can be distributed by next generation composite type IV storage tankers to dispersed asphalt and cement sites.

Hydrogen could be a key contributor to reducing emissions associated with these industries as a fuel enhancer (cement) and 100% fuel switch (asphalt). Given that these sites are mainly dispersed across the UK, and not all are connected to the natural gas network, delivering hydrogen to sites has been a key area of investigation. Hydrogen trucking options could be a cost-effective longer-term solution for asphalt sites whose requirements fit well with quantities of H_2 delivered by single journeys.

All aspects assessed by the project have concluded that the end-to-end concept is technically feasible. The chosen electrolyser technology coupled with nuclear steam and electricity would provide high purity hydrogen at 28kg/hr that could be used as a direct replacement of current fuel in asphalt industry or as a fuel enhancer in cement manufacturing. Both assessed end use sites could technically utilise hydrogen as a fuel within the respective combustion processes with engineering modifications and installation of new equipment. The assessed cement site requires minor modification for pressure reduction but otherwise the primary rotary kiln can burn blends of hydrogen. The assessed asphalt site would require the installation of a pressure reduction skid, control systems, pipes, valves, and burners, all of which is technically possible.

There is a high initial Capital Expenditure (CAPEX) investment to decarbonise both cement and asphalt sectors, especially in electrolyser development, with unpredictable Operational Expenditure (OPEX) as currently energy market prices and volatility create issues for any production technology in the near term.

Our analysis shows that if (SOEC) technology were to be demonstrated and developed further, by 2035 the overall cost of the system would be lower than comparable technologies, Figure 2. The technology developed from this demonstration would be applicable for other nuclear power stations, including Sizewell C and future Small Modular Reactors (SMRs) and Advanced Modular Reactors (AMRs). A future 100MW scale SOE system could deliver cost-competitive hydrogen by 2035, with further potential cost reductions in transport if higher utilisation and long-term contracts with hauliers can be secured.

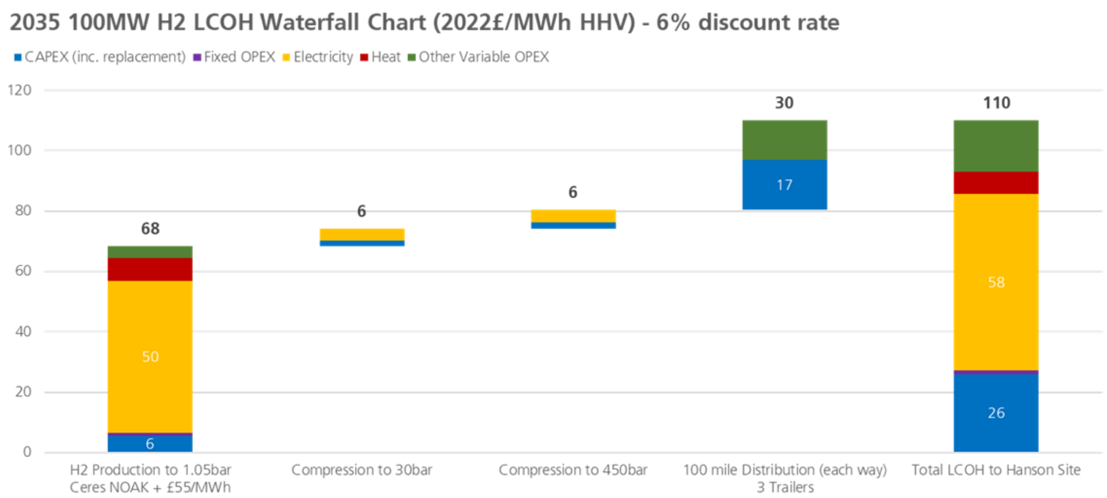

Figure 2 Future 100MW Commercial scale SOE Plant

The concept for using hydrogen within cement has already been proven; however the main aim of the previous trial was to prove that a cement kiln can operate on a net zero fuel mix, incorporating additional low carbon fuels that are arguably not currently commercially viable. The innovative concept for Stream 2B, within the cement demonstrator, would be to assess if hydrogen can be used as a fuel enhancer. The main burner of the cement kiln can be sensitive to fuel quality; therefore, an assessment will be made if hydrogen can enhance the overall fuel mix net calorific value (NCV) in order to increase the use of lower NCV waste derived fuels.

Carbon capture is a key lever to decarbonise cement production, as approximately 30% of the total CO_2 emissions are fuel derived and the other 70% are from the raw materials. A typical cement kiln has an annual thermal energy demand of 830 GWh/yr. Hydrogen is currently considered a high-cost low carbon fuel, however using hydrogen as a fuel enhancer could broaden the use of lower grade, lower cost and higher biomass waste derived fuels. Biogenic CO_2 emissions from using hydrogen enabled waste fuels could present the opportunity for carbon negative cement production.

Within the asphalt industry, to the best of our knowledge, hydrogen has not yet been proven as a fuel switching option. A typical asphalt plant has an annual thermal demand of 16 GWh/yr. The electrification of an asphalt plant could be difficult as the asphalt manufacturing process can be subject to significant variation in thermal demand, therefore this would require significant load demand stabilisation if connected to the national grid. There are currently a limited amount of low carbon fuels available for asphalt manufacturing. If fuel switching to hydrogen can be proven, this could be one of the most promising decarbonisation levers within the asphalt industry.

Detailed engineering design within this feasibility study predominantly focuses on asphalt, as hydrogen ready equipment has already been successfully tested within cement. However, to assess the innovative concept of hydrogen being a fuel enhancer within cement, the demonstration section of this report focuses on some common equipment that can be used on both manufacturing processes.

The economic Key Performance Indicator chosen for benchmarking the viability of fuel switching to hydrogen is the cost of reduced CO_2 (CORC). This KPI compares cost of produced product (COP) and specific CO_2 emissions (e) with and without the implementation of H_2 fuel switching.
For Asphalt the cost of CO_2 avoidance appears high (163 £/t CO_2) when compared with carbon capture and storage (CCS) techniques, however CCS needs to be further explored for asphalt systems as compatibility with 'standard' system could be difficult due to frequently varying fuel combustion. Fuel switching to alternative fuels such as hydrogenated vegetable oil (HVO) could currently cost 40% less than hydrogen fuel switching; however, unlike hydrogen, HVO would still result in scope 1 CO_2 emissions from the process, albeit biogenic. It is also important to note that HVO supply can be in some cases volatile and ethical questions around its land use for production need to be further explored.
The analysis shows that the cost of hydrogen heavily impacts the CORC value - if hydrogen transmission could be carried out via pipeline, then the CORC value could reduce by 25-30%.
For Cement, the cost of CO_2 avoidance appears attractive when using hydrogen as a fuel enhancer for waste fuel that contains a proportion of biomass, the main aim of the demonstration is to test this theory. CORC of CCS within cement is better understood and previous studies suggest that it should lie in the range of 50 to 150 £/tCO_2. When assessing hydrogen as a fuel enhancer it is clear that even small amounts of hydrogen can significantly increase the overall fuel mix net calorific value (NCV), a minimum threshold for NCV of the main burner fuel mix is around 21 MJ/kg. Therefore, small amounts of hydrogen could prove to be a very good fuel enhancer allowing more than a 5% increase in waste fuel as proposed in the cost analysis.

It is important to note that the proposed demonstrator qualifies for the Low Carbon Hydrogen Standard (LCHS) as carbon intensity is expected to be at 1.2g gCO_2e/MJ LHV (assuming emissions intensity of Sizewell C project at 3.35gCO_2/kWhe). The LCHS requires the emissions intensity of hydrogen production to be 20gCO_2e/MJ LHV or less.

In terms of future commercialisation, the consortium envisages continuing to operate the plant providing hydrogen to the end use sites if the demonstration has been successful and it is economically viable to do so. This is dependent on ongoing operational cost support such as through the Hydrogen Business Model (HBM) or other means of commercial support. The consortium vision is that the demonstrator would lead to immediate and long-term benefits to Hanson's sites and pave the way for conversion of other sites if it can be shown to continue to operate reliably and economically.

Additionally, future nuclear projects are targeting cost reductions through a number of routes, including increased factory production, reduced construction schedules, plant design simplification, and learning from building multiple units. AMR and SMR technologies have potential for decreases in Levelised Cost of Hydrogen (LCOH) via reduction of CAPEX and OPEX costs and because of their cogeneration capacity.Cost reductions for nuclear alongside expected capital cost reductions of electrolysers therefore present an opportunity to improve the competitiveness of clean hydrogen in a future energy system. Furthermore, integration of reactor heat into SOECs should deliver a further cost reduction per unit of hydrogen.

As presented in Figure 3 LCOH from AMR nuclear electrolysis is expected to be competitive with wind coupled Proton Exchange Membrane (PEM), reaching as low as £60/MWh by 2040, almost as low as mature methane reformation. Also, AMR technology (with standard financing) is expected to be more competitive than GW scale nuclear technology with advanced financing.

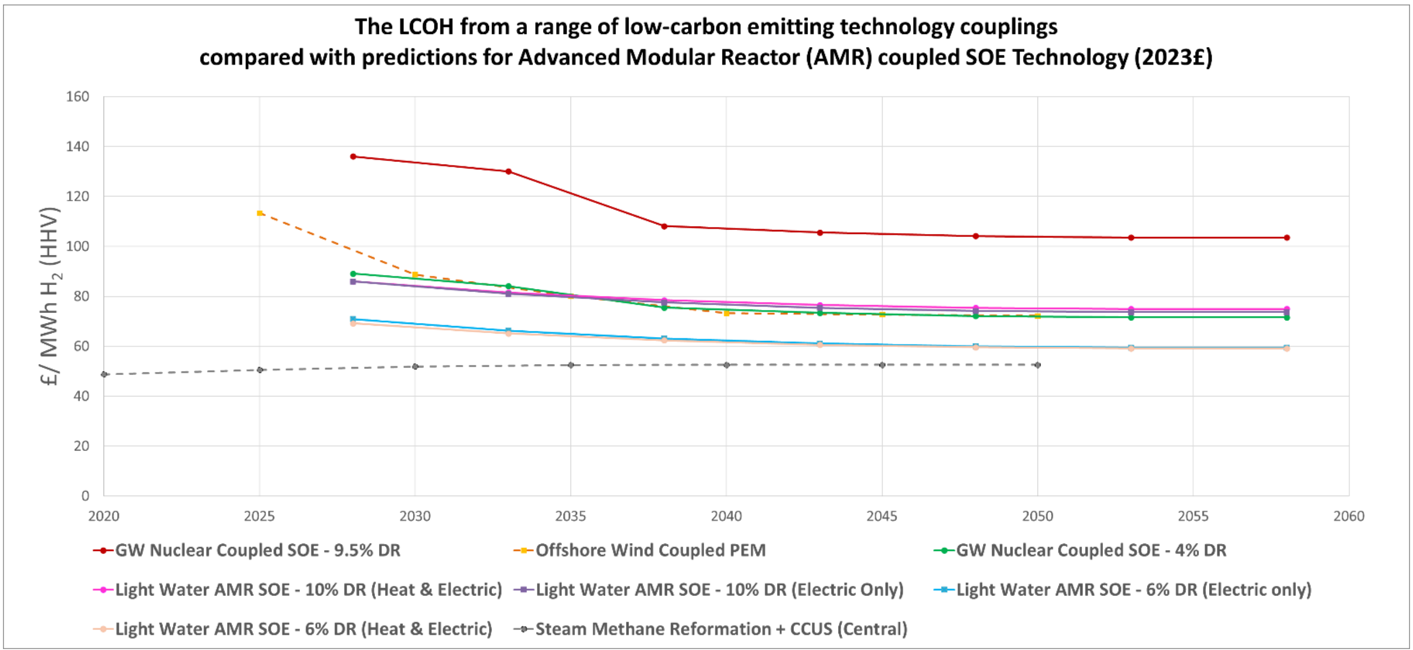

Figure 3- LCOH of AMR coupled SOE technology (BEIS assumptions) compared against a range of low-carbon technology couplings. (DR=Discount Rate)

It is also important to note that decarbonising of industry through hydrogen could lead to the creation of thousands of jobs, maintain existing jobs and upskill the current industrial work force. The UK Government indicates that the hydrogen economy could be worth over £900 million and provide 9,000 jobs by 2030, up to 100,000 by 2050. This analysis includes the whole value chain of hydrogen, from its production, through distribution to end use. Production of hydrogen utilising nuclear to meet the forecast demands for industry could provide between 18,000 and 59,000 jobs.

Table 1 Estimated requirements of reactors and jobs created to meet 25TWh and 105TWh Hydrogen demand from nuclear

Scenario	Hydrogen Demand Estimate (TWh)		Estimated Fleet Requirement		Jobs after scaling	
	Central	Maximum	Central	Maximum	Central	Maximum
Industrial Use	25	105	5 SMRs/AMRs	20 SMRs/AMRs	18,001	59,403

Key Learning points from the project are:

- H_2 production on site at nuclear plant using steam is technically possible and could deliver a step change in hydrogen production efficiency (producing 30% more hydrogen for the same overall energy input than conventional PEM and Alkaline electrolysis).
- Greatest gain in efficiency for SOE technology is from using steam supplied at 150-200°C and higher temperatures. Additionally, SOE technology development will lead to its cost competitiveness in the coming 5-10 years.
- The Heysham 2 nuclear station is currently lower tier COMAH and the additional storage requirements for this project will not change this. In line with best practice the station would look to minimise volumes of flammable/explosive materials on site (top tier COMAH >=50tonnes H_2 if only H_2).
- Nuclear safety case requires review and update to capture the risks associated with H_2 production, storage and compression on site. Station Safety Reports (SSR) will require modification concerning the unscheduled release of hydrogen.
- Hydrogen compressor equipment at low flow rates and high compression ratios is not currently well developed in the UK and expensive at low flow rates, however economies of scale should reduce cost pressures.

- Type IV composite storage containers for transport and stationary applications provide a step change in hydrogen volumes delivered per journey and improve the overall competitiveness of trucking hydrogen for longer distances.
- The selected 45ft 380bar container system developed by NPROXX conforms to the Transportable Pressure Equipment Directive (TPED), applicable to the valve and pressure cylinders used as part of the product. However, they require careful management of temperature ranges during loading and unloading.
- Higher H_2 pressures (above 380bar) do not result in large increases in H_2 mass due to increased cylinder space requirements because of larger wall thicknesses.
- Using trucks to deliver H_2 to end-users will require redundancy in equipment to ensure H_2 supply on site – e.g., three container systems required rather than two.
- Different asphalt sites have different burner manufacturers and input fuels. Each burner manufacturer has different Research and Development (R&D) timelines for H_2 firing which may impact speed of uptake within the industry
- Impact of H_2 combustion on asphalt is not expected to be adverse. However, greater moisture content in flue gases may reduce life of downstream gas filters. Additionally, converting end-use asphalt sites requires detailed assessment of site space constraints.
- The use of hydrogen as a fuel enhancer for cement could broaden the use of lower grade, lower cost and higher biomass waste derived fuels.
- No significant safety issues have been identified, although further actions are required to comply with Dangerous Substances and Explosive Atmospheres Regulations (DSEAR), Control of Major Accident Hazards (COMAH), Pressure System Safety Regulations (PSSR), and Devices intended for use in Explosive Atmospheres (ATEX). Further specific demonstrator assessments are required to confirm DSEAR zones and ATEX equipment requirements.
- Asphalt sites are not COMAH regulated and for flexible, cost-efficient operation should remain that way. As such, on site storage limits must be carefully managed to ensure H_2 on site does not breach these limits. Currently at the assessed site 2.4 tonnes of H_2 would push the site in aggregate into the lower tier. Future switching to H_2 may reduce the need to store other fuels onsite as Liquefied Petroleum Gas (LPG), or Processed Fuel Oil (PFO), and such increase the allowable limit of H_2 storage.

A qualitative key lesson of this project is the learnings shared between the partners, subcontractors and engaged equipment suppliers. This is an invaluable intangible benefit that will ensure the use of hydrogen is considered within the asphalt and cement sectors, and knowledge of nuclear derived hydrogen and high-pressure trucking solutions is disseminated outside of these sectors.

In summary, the proposed demonstrator is technically feasible and will bring significant benefits to the decarbonisation of cement and asphalt, while advancing the key H_2 production method of SOEC coupled with nuclear heat and electricity.

2. Introduction

The “Bay Hydrogen Hub – Hydrogen4Hanson” project is intended to be a key step towards the decarbonisation of the cement and asphalt industry, developing nuclear hydrogen production and investigating technologies to deliver hydrogen to dispersed industrial sites. This project was awarded funding as part of Net Zero Innovation Portfolio (NZIP), Industrial Hydrogen Accelerator programme by Department for Energy Security and Net Zero.

Our consortium vision is to demonstrate SOE integrated with nuclear heat and electricity, producing low-carbon, low-cost hydrogen and delivering via novel, next generation composite type IV storage tankers to dispersed asphalt and cement sites. SOE utilises electricity and heat to provide a step change in production efficiency vs other technologies using feedstocks that can both be provided from low-carbon nuclear power.

2.1. Nuclear Hydrogen Production

Nuclear heat can be used not just to provide thermal energy for conversion to electricity, but also as a direct feed into cogeneration technologies. SOE is one such technology that has demonstrated at small scale great potential to improve the overall energy efficiency of electrolysis, producing 30% more hydrogen for the same overall energy input than conventional PEM and Alkaline electrolysis. Both these conventional technologies have been considered previously at Heysham (1), with learnings feeding into this project, but the coupling opportunity that SOE provides greatly increases the value-add nuclear energy can provide to the growing hydrogen industry. Demonstrating this coupling at scale is a vital step to showcase the synergies.

Heysham 2 has been home to a standalone electrolyser (now decommissioned) to supply hydrogen to the on-site generators since it was first designed, and as such, hydrogen production and use is embedded within the original safety case, improving the feasibility of siting an electrolyser at the plant. Furthermore, nuclear sites offer the perfect coupling with electrolysis, with readily available power systems, on site de-mineralised water and nitrogen (for electrolyser purging), instrument air and low carbon electricity. This project has investigated using the available auxiliary steam from the turbines to supply heat to a next generation SOE.

2.2. Cement and Asphalt End-Use

The UK cement and asphalt industries emit 6.3MT (2021) and 0.5MT (2020) of CO_2e per annum across 10 cement and c.275 asphalt production sites respectively (2) (3) (4). This contributes c.9.2% of total UK industrial emissions (73.2MT 2020 (5)), and 1.6% of total UK emissions (2021 (6)). Hydrogen could be a key contributor to reducing emissions associated with these industries as a fuel enhancer (cement) and 100% fuel switch (asphalt). Given that these sites are mainly dispersed across the UK, and not all are connected to the natural gas network, delivering hydrogen to site is a key area of investigation.

All asphalt plants use conventional burners of similar design, rated at 10-25MW. The majority of the c.275 plants in the UK use liquid fuels such as kerosene or reclaimed fuel oils (e.g., Processed Fuel Oil). This high energy requirement makes direct electric alternatives challenging due to limitations on the electricity grid network and other technical factors. Hydrogen could be used as a 100% replacement for the current fuel and demonstrate a sustainable zero carbon alternative for asphalt production. We understand that this has never been demonstrated previously at plant scale and would represent a world first innovation that could be readily transferable to the wider UK industry sector.

Carbon capture has limited application in asphalt, not only due to the technology predominantly being pioneered in cement but also due to asphalt’s ‘non-continuous’ process. Furthermore, asphalt sites are widely dispersed throughout the UK, which does not align with existing Carbon Capture & Storage (CCS) plans. Thermal power fluctuations, and frequently changing products, makes carbon capture difficult. Alternate fuel sources such as biodiesel and biogas are in development, however we believe that hydrogen derived from nuclear, or Renewable Energy (RE) sources, could provide a sustainable solution that will undoubtedly play a major part in the long-term de-carbonisation of the mineral products sector.

The project has investigated the feasibility of hydrogen as a fuel at both asphalt and cement plants operated by Hanson. By investigating both asphalt and cement, the project has de-risked the end-use feasibility, providing two potential routes for demonstrating H_2 fuel switching.

2.3. High Pressure Hydrogen Transportation

Delivering low-carbon fuel to dispersed sites that are not connected to the natural gas grid is a key consideration. Hydrogen could either be delivered by trailers, or production facilities constructed at site. However, asphalt plants are generally restricted for space and they operate in batches. This mode of operation would necessitate either low load factors for H_2 production or on-site storage. Hence delivery offers a more flexible solution. Current tube trailers transport c.200-300kg of hydrogen per trip at pressures of c.200bar. Increasing the pressure and capacity of trailers could drastically improve the economics of transporting hydrogen. NPROXX deliver up to 45ft trailer systems that can store 1200-1600kg of hydrogen at pressures from 380 to 640bar. The project has investigated the feasibility and logistics of using these containers to marry production with end use. Large numbers of asphalt plants are not gas grid connected and the costs to connect are prohibitive. Fuels are transported in and stored on site. Hydrogen trucking options could be a cost-effective longer-term solution for asphalt sites that fit well with quantities of H_2 delivered by single journeys. For other sites and industries, trucking hydrogen in is a no-regrets option to quickly deliver fuel and accelerate the low-carbon transition.

2.4. Project Objectives

This feasibility study is the precursor project to a Megawatt (MW) scale demonstration of this end to end (production to end use) value chain and is highly applicable to future technology options and fleet deployment possibilities.

The feasibility study is delivered as a consortium of partners each with expertise in the life cycle of production, transportation, end use and future developments of low carbon hydrogen:

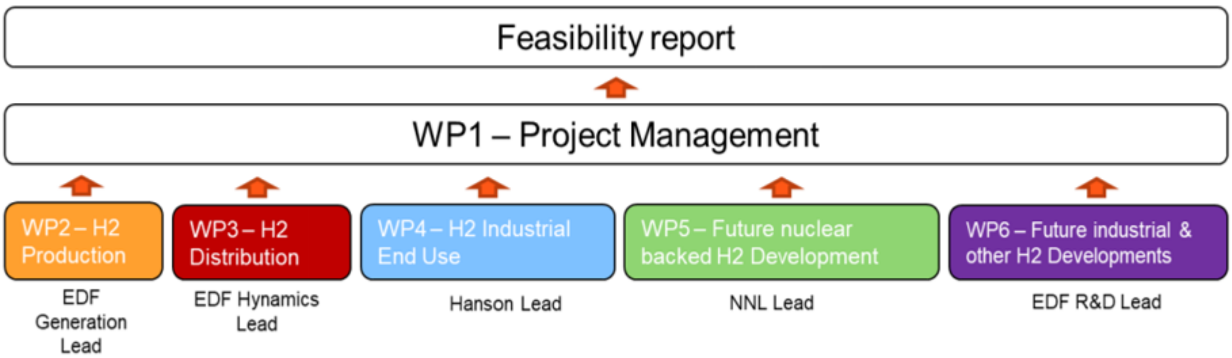

Figure 4 - Feasibility study work package breakdown

- Assess the engineering and regulatory requirements for siting an SOE at the Heysham 2 nuclear station, connecting to the auxiliary steam system and electrical utilities
- Develop an engineering design for hydrogen production and compression at the Heysham 2 site, capturing any challenges, limitations, and opportunities
- Investigate the engineering feasibility and economics of transporting hydrogen via high pressure composite tube trailers
- Develop an engineering design for converting an asphalt site to hydrogen, identifying equipment development challenges and site restrictions
- Produce a workable end-to-end solution that marries hydrogen production volume and timing with delivery options and end-use business as usual operations
- Investigate the future commercialisation and scalability of the production, distribution and end-use hydrogen technologies and applications.

3. Main Outputs & Findings

All aspects assessed by the project have concluded that the end-to-end concept is technically possible. Key findings and insights have been discovered which informed and developed the engineering to design a feasible solution. These aspects have greatly improved the consortiums understanding of what is required to decarbonise dispersed industrial sites utilising H_2 produced using nuclear heat and electricity via a SOE.

3.1. Performance

3.1.1. Delivered Hydrogen

The Ceres technology coupled with nuclear electricity and steam, including onsite electrical requirements requires c.37kWhe/kgH_2 and 13.9kWhth of heat in the form of steam at 180ºC and 9barg. The steam consumption should be considered a maximum requirement for the demonstrator, with expected increases in steam utilisation decreasing the demand. Electrical requirements are estimated and will change depending on air, steam and drying requirements. Converting this heat to electricity results in total electrical equivalent efficiency of 42.9kWhe/kgH_2 or 78% efficiency on Lower Heating Value (LHV) basis. An additional 3.6kWhe/kgH_2 is required for each stage of compression, resulting in a total process efficiency (electrical equivalent basis) of 50kWh/kgH_2 (66.7% LHV basis). The electrical requirements for compression stages are estimated conservatively based on supplier specifications, but actual power consumption varies with flow rate and compressor technology. The low-pressure compressor generally will require more power compared to the high-pressure compressor due to the increased work needed for higher compression ratios. The installed Ceres 1MWe system would provide 28kg/hr of H_2, at a purity of 93-97% with a moisture content of 3-7%. The addition of a dryer would boost the purity to >99%. Improvements in efficiency for a future 2035 system could increase output to 29kg/hr with reductions in steam requirements of up to 35%.

Table 2 - System Performance

	H_2 production	Compression to 30bar	Compression to 450bar	Total Process	Units
Electricity in	1034	100	100	1234	kWe
Heat in	388.6	0	0	388.6	kWth
Heat in (lost electricity generation)	163.2	0	0	163.2	kWe
H_2 output	28	28	28	28	kg/hr
System efficiency	42.8	3.6	3.6	49.9	kWhe/kg H_2
	77.9%	89.3%	89.3%	66.7%	% LHV

Levelised Cost of Hydrogen

Initial levelised cost of hydrogen (LCOH) modelling indicates that for the demonstrator the total delivered LCOH is c.£542/MWh Higher Heating Value (HHV) vs current market rates of £230-600/MWh HHV, based on a wholesale electricity price of £135/MWhe. Projections for 2035 indicate that this could reduce to £110/MWh HHV.

3.1.2. Carbon Abatement Potential

Low Carbon Hydrogen Standard

The Low Carbon Hydrogen Standard (LCHS) requires the emissions intensity of hydrogen production to be 20gCO_2e/MJ LHV or less. Under the assumptions made in the LCHS, the demonstrator project would produce H_2 with an emissions intensity of 5.2gCO_2e/MJ LHV, demonstrating compliance with the standard. However, the carbon intensity of electricity for nuclear used within the standard is 14gCO_2e/kWhe, covering emissions at the point of production (raw materials, upstream suppliers, and operation of H_2 plant), whereas for Renewables (solar and wind) the number used is 0.

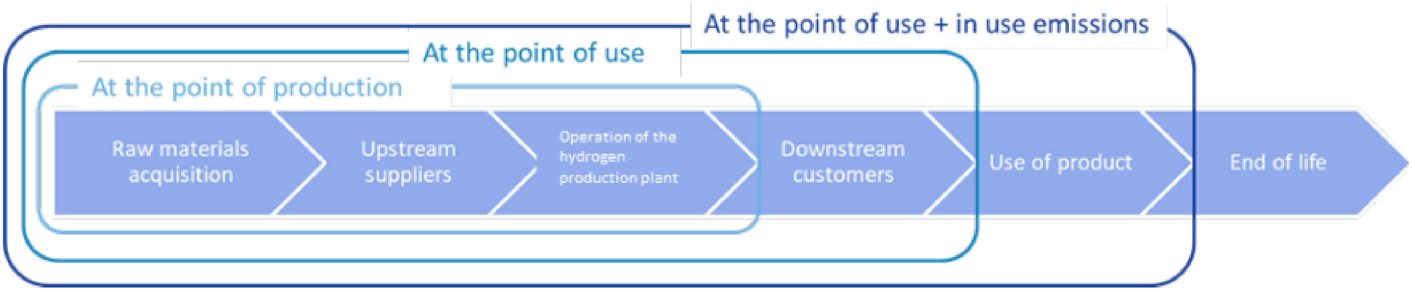

Figure 5 - LCHS Methodology - in scope emissions

The IPCC fifth assessment report WG3 Annex III states that direct emissions from nuclear are 0 (as are solar and wind) (7). Median lifecycle emissions are 12, 48 and 12gCO_2e/kWhe respectively (nuclear, grid solar, offshore). Furthermore, recent work undertaken by EDF on the SZC project indicates much lower emissions of c.3.35gCO_2e/kWh for upstream and core operations. This number has a significant impact on the LCHS calculation for nuclear H_2, reducing the intensity by a factor of 4.2.

Table 3 - H_2 Production to 450bar carbon intensity comparison - variation in gCO_2/kWhe from nuclear

	LCHS Nuclear	SZC Nuclear (8)	Units
Emissions Intensity	14	3.35	gCO_2/kWhe
System boundary	Raw materials acquisition, Upstream suppliers, Operation of the production plant	Upstream (2.27 gCO_2e/kWh), Core operation (0.6 gCO_2e/kWh)	-
LCHS Result	5.2	1.2	gCO_2e/MJ LHV

Although the proposed demonstrator qualifies for the standard, emissions intensity values vary significantly, and the standard in its current format does not align with data on new nuclear plants in the UK.

Asphalt Industry

The majority of the 280 plants in the UK use liquid fuels such as kerosene or reclaimed fuel oils, resulting in average production carbon intensity of c.25kg/tonne of product, of which 22.6kg/tonne is from combustion emissions (c.77.5kWhth LHV per tonne asphalt). All asphalt plants use conventional burners of similar design, rated at 10-25MW. This high energy requirement makes direct electric alternatives challenging, especially for variable batch plant processes due to limitations on the electricity grid network and cost of grid connection. There are currently no known plans to develop electric rotary kilns for the asphalt sector.

Hydrogen will be used as a 100% replacement for the current fuel and demonstrate a sustainable zero carbon alternative for asphalt production. We understand that this has never been demonstrated previously at plant scale and would represent a world first innovation that could be readily transferable to the wider UK industry sector. Alternate fuel sources such as biodiesel and biogas are in development, however we believe that hydrogen derived from nuclear, or renewable sources, could provide a flexible, secure, and sustainable solution that will undoubtedly play a major part in the long-term de-carbonisation of the sector. Use of hydrogen fuel could reduce asphalt industry direct carbon emissions by c.560kT p.a. (c.22.6kg per tonne of asphalt).

Cement Industry

Clinker production emits c.800kg/tonne of which 270kg/tonne are combustion carbon emissions. The UK's manufacturing sites are mostly modern designs of cement kilns, meaning around 50% of the total energy can be derived from waste derived fuels, which are currently being sourced with increasing amounts of biomass content. The other 50% of process heat input is very sensitive to fuel quality, biomass fuels are typically a lower grade fuel than conventional fossil fuels, therefore enhancements within the combustion process are needed to achieve very high levels of fuel biomass content within the cement manufacturing process.

Hydrogen could be used as a fuel enhancer for harder to burn, high biomass content fuels. Across most, if not all, cement manufacturing sites globally, the part of the process where the hydrogen will be injected is susceptible to issues when burning lower grade fuels. Therefore, the use of hydrogen as a fuel enhancer could assist the production of low carbon cement in the UK and worldwide, without expensive replacement of capital equipment for unproven alternatives such as electric kilns.

Initial calculations indicate that with just a c.2% blend of H_2 by energy, the proportion of low-cost lower-carbon waste derived fuels increases (by c.5%) such that 6kgCO_2e per tonne of clinker can be saved, which equates to c.42kT annually from the UK cement industry based on 7m tonnes of production.

Furthermore, just using hydrogen blends up to 30% by energy alongside coal, total emissions from the UK cement industry (6.28MT in 2021) could be reduced by c.565kT, a reduction of 9% p.a. However, this number is not considering the potential increase of waste derived fuels, which could make up the remaining fuel mix and potentially reducing cement combustion emissions to close to 0 (a c.1.7MT reduction p.a nationally).

Levelised Cost of Abatement

- **Asphalt:** Using the commercial scale hydrogen cost and the indicative capex costs for conversion, the cost of carbon abatement in 2035 excluding carbon emissions taxation is £163.5/tCO_2e which equates to a £3.7 additional cost per tonne of asphalt when using 100% hydrogen. This compares with a Greenbook forecast carbon tax of £302/tonne in 2035. Hydrogen would reduce total emissions by c.90%.
- **Cement:** Using only a 2% hydrogen blend as a fuel enhancer would increase the proportion of waste derived fuels (paper, plastic) that can be used, reducing emissions by c.7% at a cost of £50/tCO_2 in 2035. Furthermore, higher blends of H_2 could enable much higher proportions of waste derived fuel, totally removing coal. Coupled with CCS for the fundamental chemical reaction emissions, hydrogen could lead to higher proportions of biogenic fuel used which in turn combined with future installed CCS technology would lead to net-negative emissions for cement works, a target of the industry.

Further details on cost of abatement are in section 4.2.5 .

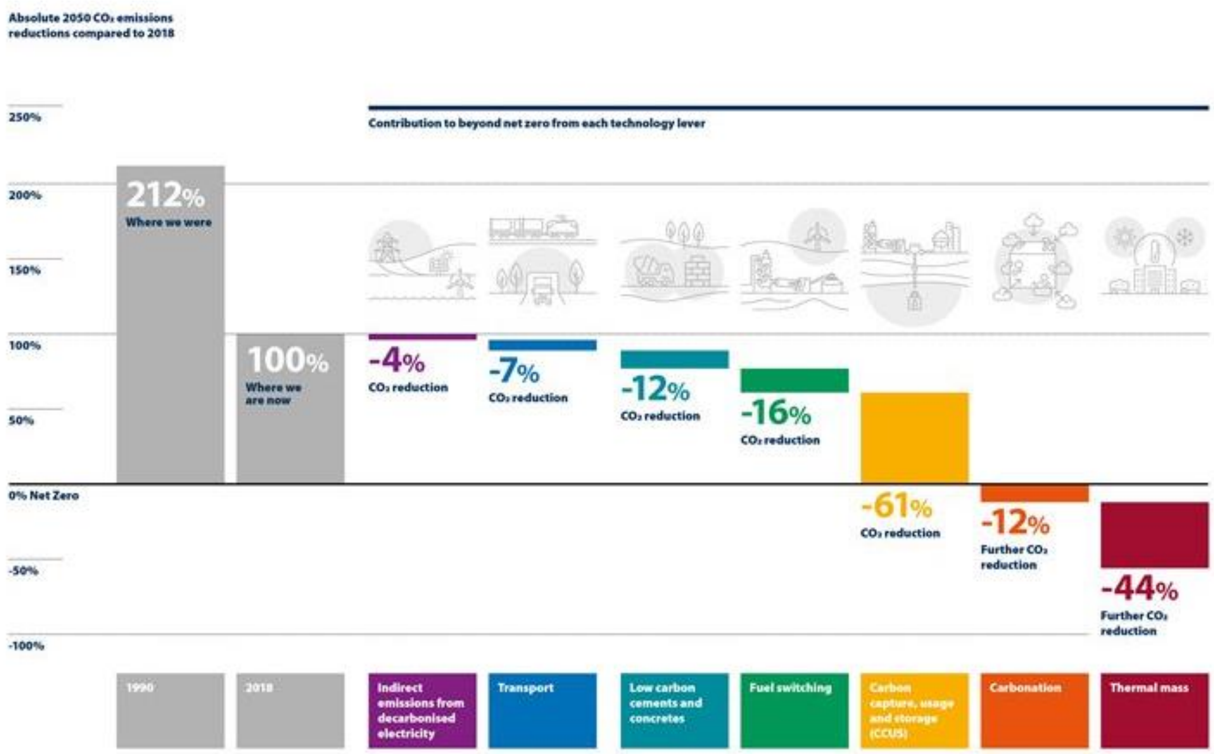

Figure 6 - Mineral Products Association UK Concrete Roadmap to Beyond Net Zero

3.2. Technical and Regulatory Feasibility

3.2.1. Production and Compression

The concept design work undertaken as part of the feasibility study has indicated that a hydrogen production facility within the nuclear licence site boundary can be feasibly installed at the Heysham 2 power station. The site currently stores hydrogen for use within the generators, and an alkaline electrolysis plant was previously a part of the original power plant design. The site work has focused on site layout, access and egress, utility connections, and safety.

The proposed site area has been down selected through engagement with the onsite Security, Chemistry, Environmental safety, Design Engineering and Nuclear Safety teams to ensure that the location meets the requirements for safety, both nuclear and associated with hydrogen, and there is available access and egress for vehicles to load hydrogen and leave site. Station Safety Reports (SSR) will require modification concerning the unscheduled release of hydrogen.

Other regulations that apply to the proposed installation include:

Reference	Description
EU Directive 94/9/EC	ATEX Equipment Directive
HSE DSEAR:2002	The Dangerous substances and Explosive Atmospheres Regulations
PSSR 2000	Pressure Systems Safety Regulations
BS EN 60079-10-1	Explosive atmospheres. Classification of areas. Explosive gas atmospheres.
COMAH 2015	Control of Major Accident Hazards regulations

Table 4 - Relevant Regulations for Heysham Site

The existing hydrogen storage compound requires 3m zoning around each mechanical joint or depressurisation vent carrying hydrogen. All equipment within this zone must be ATEX rated at IIC. Furthermore, the compression equipment and storage tanks on site will comply with the PSSR 2000 regulations.

The Heysham site is already a lower tier COMAH installation. The maximum additional hydrogen that can be stored at site is 27 tonnes before the higher tier COMAH threshold is reached.

The proposed SOE technology can be integrated with the existing onsite auxiliary steam supply, which is currently 180ºC and 9barg, but will likely increase with planned site modifications during 2023 and 2024 to 200ºC and 9barg. This can be supplied at a flow rate up to 600kg/hr, which is bled from the steam chests of the intermediate stage of the installed turbo generators at Heysham 2. The electrolyser requires a steam flow rate of 504kg/hr and a power input of 1,015kWe (including parasitic loads) to produce c.28kgH_2/hr (1,103 kW H_2 HHV). The steam consumption should be considered a maximum requirement for the demonstrator, with expected increases in steam utilisation decreasing the demand. Electrical requirements are estimated and will change depending on air, steam and drying requirements.

Further details on the production concept design and analysis undertaken by EDF Generation and Ceres Power, however due to commercially sensitive nature of the information contained within, they cannot be disclosed in this public report.

3.2.2. Distribution

The currently selected 45ft 380bar multi-element gas container system developed by NPROXX conforms to the Transportable Pressure Equipment Directive (TPED), applicable to the valve and pressure cylinders used as part of the product. The pressure cylinders are Type 4 composite systems made of carbon fibre. These are certified to TPED and EN17339 standards. The operating temperature range of the cylinders is -20ºC to 65ºC.

During loading, the cylinder temperature increases, and so in times of extreme heat (c.+40ºC), a chiller unit will be required, or the loading flow rate managed to moderate cylinder temperature. Furthermore, on unloading, the cylinder temperature conversely drops as hydrogen is dispensed. In times of cold weather, this could impact dispensing given the lowest operating temperature of the cylinders is -20ºC.

Transporting the hydrogen from the production to the end use site requires more than one tube trailer to ensure continuous supply to the asphalt or cement facility. For a 1MWe SOE system, coupling to an asphalt production facility, three trailers are required to ensure continuous supply: one filling, one unloading and one travelling to site/at site ready for switch. The demonstration phase will consider larger low-pressure storage at the production site to reduce number of trailers required to two, however there are risks with this approach for Hanson's production needs.

Logistics

Transporting dangerous goods is performed by multiple haulier firms throughout the UK. Drivers require specific training to be able to handle these loads. The International Carriage of Dangerous Goods by Road ("ADR") regulates the transport of hydrogen, which has UN number 1049, is class 2 and classification code 1F. There are multiple special provisions associated with transporting H_2, of which drivers must be aware of. Return trips of c.150km each way would cost £1100 per return journey. Routes to Asphalt and Cement sites have been considered as part of the project, with suggested routes for two sites presented. A key consideration is road suitability for heavy goods vehicles. Nuclear Power Plants, Asphalt and Cement sites all require suitable access and egress for large vehicles and so this is not considered a concern. The initial route assessment between the three concept sites utilises A roads and Motorways. Currently, Heysham would be the closest production facility to the chosen cement facility. For the asphalt sites, the Stanlow Refinery project led by Essar and Progressive Energy are closer, however this facility will not be operational in the timeframes of the demonstration project.

Asphalt Site

Heysham 2 operates 24 hrs a day and so hydrogen can be produced continuously at a flow rate of c.25-30 kg/hr. The Asphalt facility requires c.200-700 kg of hydrogen daily to operate one burner at a flow rate of about 320 kg/hr (the burner does not operate continuously). Each trailer unit has a capacity of 1200 kg (when full) and so each trailer will have an excess of 500-1000 kg after each 24hrs of defueling. A historical analysis of the daily demand profile indicates that the 1MW electrolysis unit would meet the existing demands. Peak demand days were not consecutive and irregular. The trailers also provide storage for days of lower demand.

To transport a total of around 3,900 kg of hydrogen required at the asphalt facility per week, an average of 3.5 trailer loads will be transported every week. This is based on the assumption that the asphalt facility will require 700 kg of hydrogen per day from Monday to Friday, and 400 kg on Saturday. The transportation schedule for the trailers will alternate each week. One week, three trailers will be transported in three weekday return trips, while the next week, four trailers will be transported in three weekday return trips and one weekend return trip. Over fifty weeks, this would approximately amount to 152 weekday return trips, 26 weekend return trips, and 1 single trip to transport a total of 179 trailer loads carrying 195,000 kg of usable hydrogen. The trailers will have to be transported at less than their capacity during the week to ensure a constant supply of hydrogen for the above assumption, but the weekend will facilitate the filling of the trailer to its capacity due to low demand.

Cement Site

The cement facility can accommodate large quantities of hydrogen daily as a flame enhancer for the primary kiln. Coal is currently used as the primary fuel, however hydrogen flame enhancement could lead to higher proportions of recycled fuels (waste biomass). Cement plant kilns are rated at c.100MW, which would require c.2.5 tonnes per hour of H_2. The same logistical operating regime can be used at the cement site as the asphalt site, providing technical versatility to the project. The asphalt production facility is considered as the primary off-taker of H_2 for the feasibility study, and the cement production facility shall be considered as a secondary option.

To transport a total of around 4,235 kg of hydrogen required at the cement facility per week, an average of 4.5 trailer loads will be transported every week. This is based on the assumption that the cement facility operates seven days a week and will require 605 kg of hydrogen per day. The transportation schedule for the trailers will alternate each week. One week, four trailers will be transported in three weekday return trips and one weekend return trip, while the next week, five trailers will be transported in three weekday return trips and two weekend return trips. Over fifty weeks, this amounts to 149 weekday return trips, 75 weekend return trips, and 1 single trip to transport a total of 225 trailer loads carrying 211,750 kg of usable hydrogen. The trailers will have to be transported at less than their capacity to ensure a constant supply of hydrogen for the above assumption.

3.2.3. End-Use

Both assessed end use sites could technically utilise hydrogen within the respective combustion processes with engineering modifications and installation of new equipment. The cement site requires minor modification for pressure reduction but otherwise the primary rotary kiln can burn blends of hydrogen and has done previously. The assessed asphalt site would require the installation of a pressure reduction skid, control systems, pipes, valves, and burners, all of which is technically possible. Burner Original Equipment Manufacturers (OEM) contacted initially stated development timelines for H_2 burners for asphalt would be challenging. The OEMs contacted are keen to demonstrate their technology within an operational environment and the incumbent equipment supplier has recommended 9 months would be required to develop and deliver a dual fuel burner capable of hydrogen, LPG and oil combustion. Furthermore, initial assessment of the impact on the asphalt product indicates that the increased moisture content may have an impact on component life of the exhaust gas filter. This is based on experience operating Asphalt plants with particularly moisture rich raw materials. Understanding this further is a key part of demonstration, leading to a view on equipment life impact and if a dryer would be required for the H_2 output from the electrolyser.

Dangerous Substances and Explosive Atmospheres Regulations (DSEAR) would apply to the use of hydrogen at both sites. A DSEAR assessment has previously been undertaken for the Cement site, but one would be required at demonstration for the Asphalt site. The outcomes of this assessment could impact H_2 routing. Furthermore, all installed electrical equipment operating close to the H_2 delivery equipment and pipelines would need to comply with ATEX gas group IIC due to the wide flammability range of hydrogen in air (4-74% H_2 concentration).

For Asphalt sites, a further regulatory challenge is the Control of Major Substances Hazardous to Health (COMAH) regulations. Lower tier limits for hydrogen storage are 5 tonnes at any one time. However, COMAH tiers are calculated on aggregate of all hazardous materials at a site. Pushing the site above this limit would trigger increased regulatory burden and associated costs for the facility. At any one time there could be two trailers on site, with a possible combined H_2 mass of 2 tonnes, noting that some hydrogen would have been consumed. With the planned storage of LPG, Bitumen and PFO, an additional 400kg of H_2 could push the site above the lower tier COMAH threshold. Lower-tier threshold requires the implementation of a Major Accident Prevention Policy (MAPP), hazardous substances consent, notification to HSE plus training of the relevant personnel to ensure all measures necessary to prevent major accidents are implemented. The full process can take +6months from submission plus time to develop the documentation. Additional site costs in the order of £50k per site + ongoing operational expenditure. None of Hanson's asphalt sites have lower tier COMAH status.

Because of the uncertainty in OEM delivery of a H_2 ready asphalt burner, the project has also performed a high-level review of other Asphalt sites within Hanson's business that could demonstrate the technology. Different plants have different burner OEMs.

3.3. Benefits and Challenges

3.3.1. Benefits

The end-to-end solution presented has several key benefits vs other hydrogen production, distribution, and end-use routes:

- **High efficiency H_2 production:** c.37kWhe/kg H_2 electrolysis electrical efficiency + 12kWhth low temperature (c.150ºC) steam input per kg
- **High utilisation factor with low carbon inputs:** SOE provided with zero-carbon, baseload electricity and steam from the Heysham 2 nuclear plant, c.90% utilisation
- **Flexible and scalable distribution solution:** High pressure gaseous hydrogen delivery increases mass of H_2 per trip, decreasing number of trips and hence carbon emissions per kg delivered (dependent on propulsion energy source). Trucking solution can scale with electrolyser scale and deliver hydrogen in the near term vs pipes.
- **Flexible end use:** burner design to accommodate using multiple fuel sources either separately or blended (e.g. H_2 or natural gas, inc. blending) to alleviate unforeseeable supply constraints and provide end use flexibility in volatile energy markets
- **Underpins and enables onward investment:** FOAK MW scale solution provides the evidence to scale each aspect of the approach taken to reach 10s and 100s MW scale.

3.3.2. Challenges

- **FOAK CAPEX:** High initial capital investment required, especially in electrolyser development, presents a potential initial barrier to developing the concept. This is related to scaling from concept to mass manufacturing.
- **Unpredictable OPEX:** Current energy market prices and volatility creates issues for any production technology in the near term and may make uptake of H_2 impossible for energy intensive industries such as cement and asphalt.
- **Process Risks:** There are multiple possible points of failure through the chain of production, compression, distribution and end use. For the demonstration scale, the highest risk element is likely the compression chain given the requirement for bespoke compression equipment that operates at the desired flow rate and compression ratio, two stages of buffer storage to ensure smooth compressor supply and effect of temperature on loading/unloading composite storage tankers possibly requiring a chiller unit.
- **Electrolyser supply and performance:** Long term performance of FOAK MW scale SOE is unknown which may impact utilisation rates and hence H_2 supply to site. Delivery times of equipment are currently challenging and early commitment is required to ensure timely delivery within the restrictions of the competition.

3.3.3. Future Opportunity

Long term feasibility will be determined by economics rather than technical factors. Our analysis, using Green book and Energy and Emissions Projections (EEP) Reference prices, shows that if SOEC were to be demonstrated and developed further, by 2035 the overall cost of the system would be lower than comparable technologies. Whilst Heysham 2 nuclear power station will not be operational at this point, the technology developed from this demonstration would be applicable for other nuclear power stations, including Sizewell C and Advanced Modular Reactors (AMRs). The Bay Hydrogen Hub structure could be implemented at other sites across the country, potentially leading to development of a hub-and-spoke model. Nuclear derived hydrogen would be transported via trucks (and pipelines when available) to multiple dispersed industrial sites where needed. This vision would be a viable complementary solution to the interconnected clusters approach.

With over 280 asphalt sites in the UK and the potential to reduce emissions by 560kT p.a, distributing hydrogen to these sites at low cost is paramount to its future potential. Some sites will be within economical distance of a potential future hydrogen network, whereas others will either rely on hydrogen trucked in or on-site production. Given the additional capital burden of on-site electrolysis (inclusive of increased electrical connection requirements), the likely option is delivery via trucks. A future 100MW scale SOE system could deliver hydrogen at low cost by 2035, with further potential cost reductions in transport if higher utilisation and long-term contracts with hauliers can be secured.

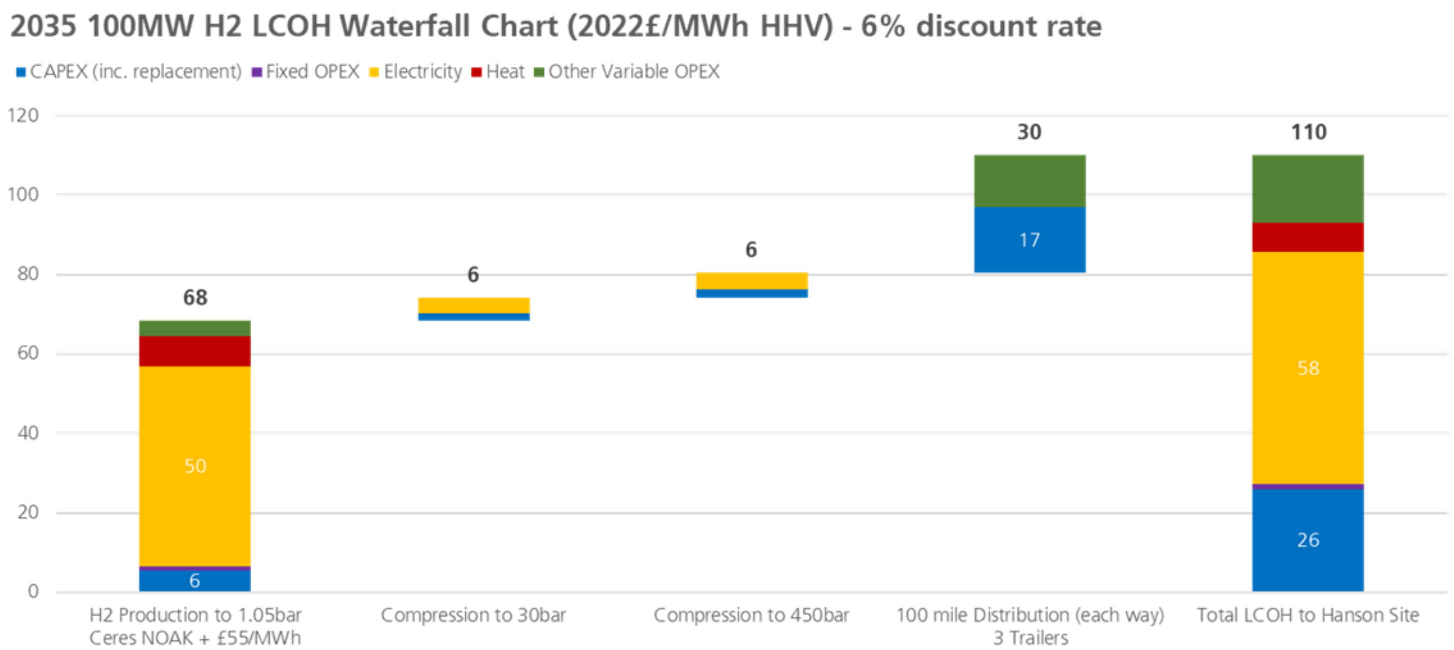

Figure 7 – 2035 Future Commercial Scale LCOH

3.4. Scalability

3.4.1. Production and Compression

Production

Existing and future nuclear power plant (NPP) designs can scale between 10's of MWth to multi-GWth scale such as Hinkley Point C (HPC) which delivers >9GWth between two reactor units. As such there are future opportunities where smaller reactors such as c.100-1000MWth Advanced Modular Reactors (AMR) and Small Modular Reactors (SMRs) could be deployed close to dispersed sites in hub and spoke supply models, or large GW units can produce bulk quantities of H_2 and connect into a future hydrogen transmission system such as that being explored by National Grid through project union. Utilising SOE technology, each 100MWth could deliver c.9,000tpa (354GWh H_2 HHV) of hydrogen vs c.7,000tpa (276GWh

H_2 HHV) through PEM or Alkaline electrolysis systems. A 400MWth AMR site could provide 36ktpa (c.1.4TWh/yr) to multiple dispersed sites, whereas a future large reactor like HPC could provide 810ktpa (c.32TWh/yr). Furthermore, the development of nuclear technology and UK government ambition of 24GW by 2050 aligns well with forecasts for hydrogen growth.

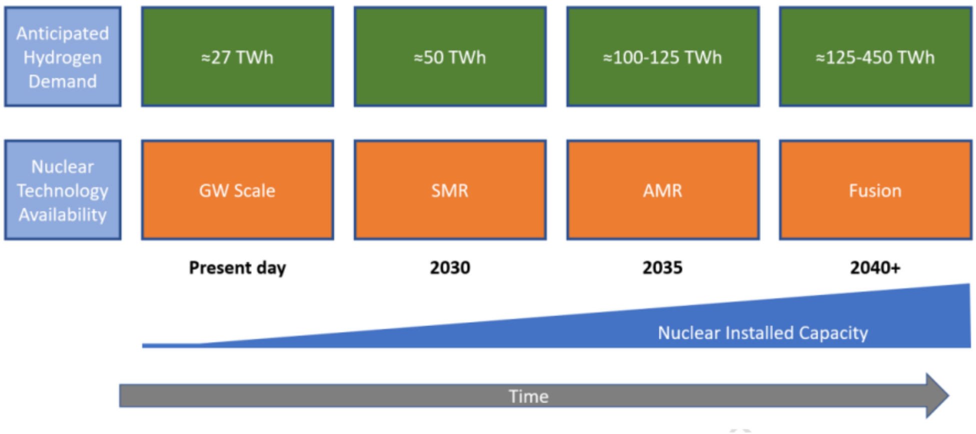

Figure 8 - Hydrogen demand & nuclear technology timeline

Electrolysis technology itself is inherently scalable, however design choices on stack size are required to ensure the most cost-effective approach to production that meets the widest consumer base. Ceres are continuing to develop and invest in this area of their technology, developing multi-MW scale modules vs the existing c.100kW systems investigated for this demonstrator. Furthermore, performance gains in terms of steam utilisation, mechanical design and operating pressure will reduce module footprint, dependent on plant integration. Upscaling manufacture and finalising the commercial design will lead to drastic reductions in manufacturing cost and hence installed CAPEX.

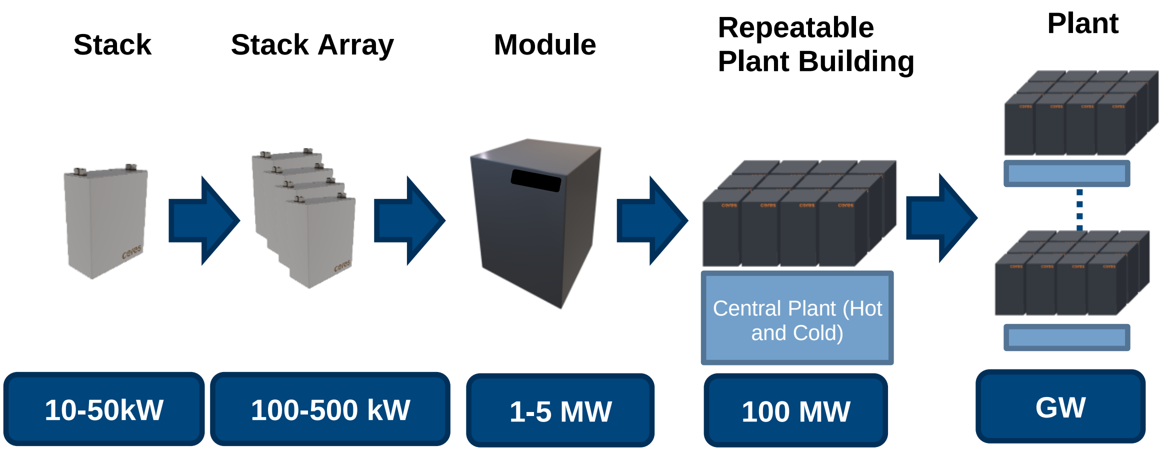

Figure 9 - Single stack to large array increase in Solid Oxide Electrolyser Cell (SOEC) technology scale

Compression

The compression regime that has been reviewed would hugely benefit from increased hydrogen flow rates. Given the size of the proposed demonstrator, fixed integration costs are apportioned over a small H_2 flow rate, as such resulting in high compression costs per unit H_2 produced. Multiple vendors of compression equipment (>10) were engaged through the feasibility study and only three of these suppliers were able to offer a quote at the time for the 1-to-30bar compressor. The main concern is the combination of flow rate (25-30kgH_2/hr) and compression ratio (1.05bar to 449bar). This requires multi-stage compression with interim storage tanks (at 1.05bar and 30bar). Larger flow rates would enable more suppliers to offer quotations and result in better economics of the system. Most suppliers offered down to 40kg/hr vs the

28kg/hr requested. The power requirements assumed for the 1 MW system are conservative, and the actual power consumption varies with flow rate and compressor technology. Typically, the low-pressure compressor will require more power than the high-pressure compressor due to the increased work needed for higher compression ratios. As the system scales to 100 MW, the compressor power requirements are expected to decrease rather than increase linearly. Further opportunities to use large-scale advanced compressor technology or improve system design could also enhance the overall efficiency of the system with increasing hydrogen production.

3.4.2. Distribution

The distribution approach taken in this project is inherently scalable and could be used to accelerate the transition to hydrogen within the end use sectors where it is the best low-carbon alternative. The NPROXX system provides the flexibility of transporting hydrogen at different pressures – 380bar, 500bar, 640bar – which can be matched to the requirements of the end user – e.g., industry vs mobility applications. Utilising the higher pressure, higher mass of H_2 trailers reduces the number of Heavy Goods Vehicle (HGV) cabs on the road to meet end user requirements, reducing transportation carbon emissions if using existing diesel cabs.

Pipelines may be the preferred route for a future hydrogen transmission and distribution system, however the capital investment required and the time to deliver a National Significant Infrastructure Project (NSIP) could limit the speed of transition. This is where investment in high H_2 mass trailer solutions can accelerate the transition by linking up end users with suppliers earlier and reducing the logistical impact on end user operations (fewer trailer loads). Furthermore, this method scales in tandem with scaling up electrolysis production, incentivising organic growth of H_2 supply and demand vs building large production facilities without the means to deliver and use the H_2.

The project envisages trailer transportation to continue to be a valuable asset to the future hydrogen economy post a national transmission network, supporting H_2 suppliers to engage with new businesses that may not be connected to a future network and where costs for connection are prohibitive, given distance and demand profile.

3.4.3. End-Use

The UK has 282 asphalt sites and 11 operational kiln cement sites (with South Ferriby closed). Estimated total emissions are 0.6-0.7MTCO_2e p.a for asphalt and 6.3MTCO_2e p.a for cement (not all cement produced in the UK is created from primary inputs, some clinker is imported and some cement substitutes are made using Ground Granulated Blast Furnace Slag (GGBS)). Estimated emissions based on daily asphalt production of a reference plant are c.3,200tpa. Asphalt sites of similar size operate all over the country, and so replicating the hydrogen solution presented could have a far-reaching decarbonisation impact nationally, rather than focused in just one area. Some of these sites may already be lower tier COMAH, but it is uncertain how many are. None of Hanson's existing sites are lower tier (c.40 sites). The sheer number of sites would ensure that burner manufacturers had multiple customers to supply, providing them with supply chain certainty for R&D development work.

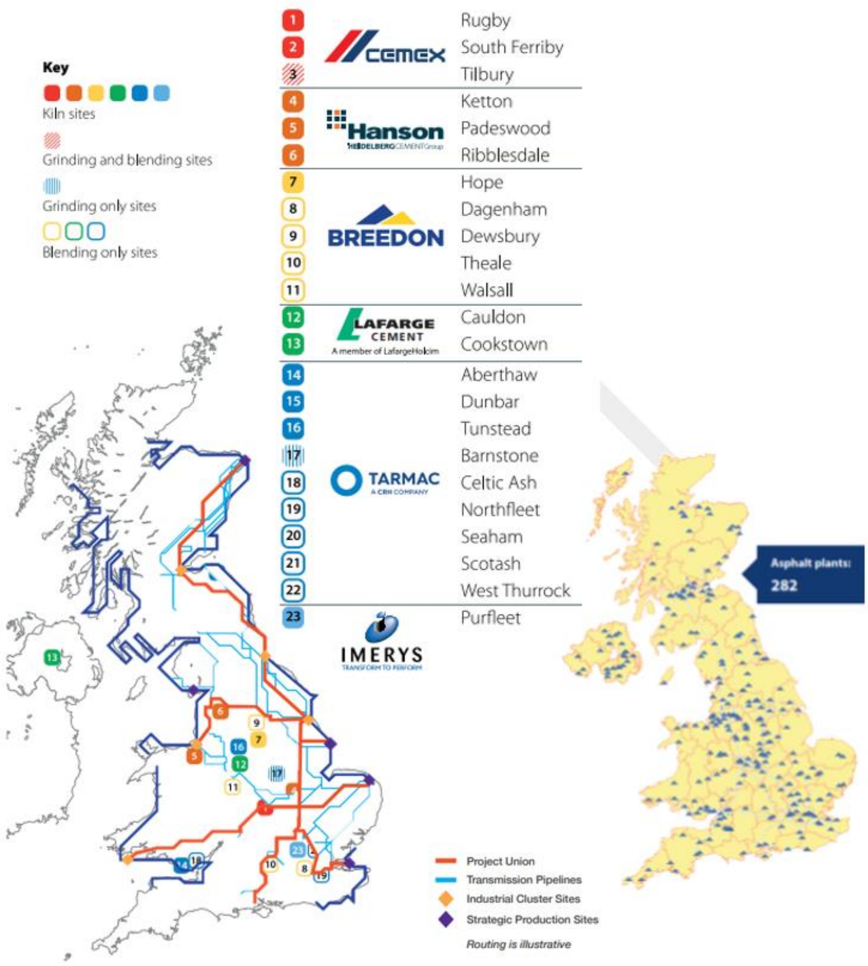

Figure 10 - Map of Cement and Asphalt sites + Overlay of National Grid Project Union Hydrogen vision

However, different asphalt plants also use different burner manufacturers given the variability in fuel used (PFO, waste oils, natural gas etc). Because of this variation in equipment, there may be a potential barrier to faster adoption of hydrogen fuel switch technology as operators will require confidence that H_2 burner technology will work with their existing rotary kilns and so will likely require their existing manufacturers to develop this technology or incur large costs in studies to certify other manufacturer designs. Conversely, once a few sites convert to hydrogen (or other low-carbon alternatives) market demand for greener products would incentivise further conversions.

There are comparatively few cement works within the UK however they contribute a much larger proportion of total industrial carbon emissions, averaging 570kT per plant (largest plant >1MT p.a). Hydrogen could play a large role in emissions reductions as a fuel enhancer. Currently, each tonne of cement produces a tonne of CO_2e, with 70% attributed to the fundamental chemical reaction to make clinker, requiring CCS for net-zero. The further 30% of fuel related emissions could be reduced by using hydrogen, resulting in a c.10% reduction in carbon emissions per tonne of cement produced from primary feedstocks. The main burner of the cement kiln can be sensitive to fuel quality; therefore an assessment will be made if hydrogen can enhance the overall fuel mix net calorific value (NCV), to increase the use of lower NCV, part biomass, waste derived fuels. The use of hydrogen as a fuel enhancer could broaden the use of lower grade, lower cost and higher biomass waste derived fuels. This could present the opportunity to either reduce the size requirements of a cement carbon capture plant, which has significant benefits to capital expenditure, or the biogenic emissions from hydrogen enabled waste fuels could present the opportunity for carbon negative cement production.

Improvements in plastic recycling will inevitably continue, reducing plastic content in waste derived fuels, reducing the NCV of fuels used in the cement industry. The proportional increase in biomass is positive from an emissions perspective but will bring combustion challenges on the main burner, making the argument that fuel enhancement is required.

The process temperatures within Asphalt and Cement operations are similar to other non-metallic mineral industries such as brick, ceramics, lime and glass. Initial pre-heat temperatures in the brick and ceramics kiln processes are similar to asphalt and the results of any asphalt trial could inform and validate results from trials in other industries at these temperatures. Glass furnaces operate at higher temperatures (c.1600ºC) and rely on radiative heat transfer effects of the dome roof, unlike the dominant heat transfer mechanisms in the continuous tunnel and rotary kilns through conduction and convection.

3.5. Key Lessons Learnt

The feasibility study has greatly improved the knowledge within the consortium on the three key pillars of a successful hydrogen supply chain. Additionally, knowledge sharing between consortium partners has increased the pool of understanding of hydrogen, developing skills and expertise in this nascent industry.

Key lessons learnt from the feasibility are:

Technical

- H_2 production on site at nuclear plant using steam is technically possible and could deliver a step change in hydrogen production efficiency.
- Greatest gain in efficiency for SOE technology is steam supplied at 150-200ºC due to the impact of the latent heat of vaporisation of water. Higher temperatures further increase efficiency, but the gain is proportionally smaller.
- SOE technology is still developing but on the cusp of commercialisation. Cost competitiveness will improve in the coming 5-10 years.
- Hydrogen compressor equipment at low flow rates and high compression ratios is not currently well developed in the UK. Focus is on 20-30bar suction pressures which may impact economic feasibility of lower pressure electrolysis designs.
- Compressor costs are high at low flow rates per unit of H_2 delivered. Large-fixed costs in design and manufacturing are apportioned across fewer kilograms of H_2. Scale should reduce cost pressures.
- Type IV composite storage containers for transport and stationary applications provide a step change in hydrogen volumes delivered per journey and improve the overall competitiveness of trucking hydrogen for longer distances.
- Type IV composite systems require careful management of temperature ranges during loading and unloading due to small allowable range of operation (-20ºC to +65ºC).
- Higher H_2 pressures (above 380bar) do not result in large increases in H_2 mass due to increased cylinder space requirements because of larger wall thicknesses.
- Different asphalt sites have different burner manufacturers and input fuels. Each burner manufacturer has different R&D development timelines for H_2 firing which may impact speed of uptake within the industry
- Impact of H_2 combustion on asphalt end product is not expected to be adverse. However, greater moisture content in flue gases may reduce life of downstream gas filters.
- Converting end-use asphalt sites requires detailed assessment of site space constraints.
- Using trucks to deliver H_2 to end-users will require redundancy in equipment to ensure H_2 supply on site – e.g., three container systems required rather than two.

Regulatory

- DSEAR, COMAH, PSSR, ATEX have all been identified as requiring compliance. Further specific demonstrator assessments are required to confirm DSEAR zones and ATEX equipment requirements
- The Heysham 2 nuclear station is currently lower tier COMAH and the additional storage requirements for this project will not change this. In line with best practice the station would look to minimise volumes of flammable/explosive materials on site (top tier COMAH >=50tonnes H_2 if only H_2).

- Nuclear safety case requires review and update to capture the risks associated with H_2 production, storage and compression on site. Station Safety Reports (SSR) will require modification concerning the unscheduled release of hydrogen.
- Asphalt sites are not COMAH regulated and for flexible, cost-efficient operation should remain that way. As such, on site storage limits must be carefully managed to ensure H_2 on site does not breach these limits. Currently at the assessed site 2.4 tonnes of H_2 would push the site in aggregate into the lower tier. Future switching to H_2 may reduce the need to store other fuels onsite (LPG, PFO) and such increase the allowable limit of H_2 storage.

Partnerships

- A qualitative key lesson of this project is the learnings shared between the partners, subcontractors and engaged equipment suppliers. This is an invaluable intangible benefit that will ensure the use of hydrogen is considered within the asphalt and cement sectors, and knowledge of nuclear derived hydrogen and high-pressure trucking solutions is disseminated outside of these sectors.

4. Stream 2B Project Delivery Plan

4.1. Project Scope

This feasibility study has covered concept engineering design for the whole end-to-end system. This includes an initial review of commercial propositions and post-demonstration commerciality of the end-to-end solution and opportunities in the UK and internationally for the project core innovations.

The Stream 2B project would cover:

- Detailed engineering design of the hydrogen production facility
- Detailed engineering design of the end use application at the cement works
- Down selection and detailed engineering design of the end use application at a Hanson Asphalt site
- Procurement of equipment
- Construction and commissioning of on-site demonstrators
- Development of testing regime
- At least 2 months of operating the end-to-end solution
- Market modelling of hydrogen production
- Carbon abatement assessment
- Ongoing development planning
- Dissemination activities: speaking at industry association events, project website, webinar and workshop
- Opportunities to extend operation beyond demonstration including review of business support mechanisms, any move to enable smaller project to qualify
- Monitoring of market value of low carbon H_2

Both EDF and Hanson have delivered similar scale engineering projects at their respective sites and although the time constraints of the project are challenging the feasibility study shows the project can be delivered within the timescales of the DESNZ funding up to March 2025.

This demonstrator would accelerate the development of SOE coupled with nuclear heat, improvements in hydrogen transportation economics and showcase the decarbonisation opportunity hydrogen can unlock within the asphalt and cement industries.

4.1.1. Hydrogen Production

Demonstration of the proposed solution will increase the system design at a nuclear site (Heysham 2) for hydrogen production from Technology Readiness Level (TRL) 5-6 to TRL7-8. The demonstration will install a c.1MWe SOE system integrated with the existing auxiliary steam supply at the site fed directly from an intermediate stage of the on-site steam turbines. Electricity will be supplied directly from the station, ensuring behind the meter prices and excluding system costs. This production facility would operate for c.2months at near 24/7 output (dependent on system reliability and nuclear plant outages/maintenance). Furthermore, there is an existing incoming 132kV supply that can also directly feed the electrolyser. Post shutdown of Heysham 2 in 2028 +/- 2 years, the electrolysis plant could continue to operate as auxiliary boilers on site would still be functioning to support defuelling and the incoming electrical supplies will be maintained for many years during defueling and subsequent decommissioning.

4.1.2. Hydrogen Distribution

The current NPROXX container systems are commercially available today and are being sold to customers for delivery in 2023 onwards. This project would further add to the base of evidence supporting higher pressure transportation of hydrogen via trucks.

Furthermore, learnings from the feasibility study on compression equipment limitations and costs for low flow, high compression ratios will continue to be investigated. SOEs produce hydrogen at atmospheric pressure, which increases the downstream cost of hydrogen vs PEM and alkaline electrolysers which produce at 20-30bar. Combining compression equipment with the SOE may be a further innovation considered as part of the project.

4.1.3. Hydrogen End Use

Asphalt Site

A key finding of the project is the low TRL of hydrogen burners for the asphalt industry and both the need to develop and the opportunity for the UK to lead decarbonisation. Within the asphalt industry, to the best of our knowledge, hydrogen hasn't yet been proven as a fuel switching option. The electrification of an Asphalt plant could also be difficult, the asphalt making process can be subject to significant variation in thermal demand, with typical burners rated at 10-25MW. This high energy requirement makes direct electric alternatives challenging, especially for variable batch plant processes due to limitations on the electricity grid network and cost of grid connection. There are currently no known plans to develop electric rotary kilns for the asphalt sector. Product development has been carried out to reduce asphalts' embodied carbon, however there are currently limited fuels available with a lower carbon intensity, that asphalt manufacturing sites can use. If fuel switching to hydrogen can be proven, this could be one of the most critical decarbonisation levers within the asphalt industry. The scope of the stream 2B project would be:

- Further assess the most appropriate end use site from the five shortlisted.
- Further develop the engineering design: work to date can be utilised for the other sites.
- Research and development on dual fuel burner system provided by Vulcan capable of combusting LPG, Oil and Hydrogen.
- Trial hydrogen fuel blends up to 100% H_2: Burner OEM's have indicated a plan to trial fuel mixing of H_2 with Natural Gas or LPG over a series of trials from c.10% H_2 by thermal input up to 100%. 12 trials are proposed to go from 10% hydrogen by energy to 100%.

Cement Site

Previous trials under the Industrial Fuel Switching (IFS) programme found the cost of CO_2 avoided was very high (€1,599/tCO_2), this was mainly driven by high costs of hydrogen and blended fuel. The trial achieved a net zero fuel mix for a few hours which proved that cement production is possible using a net zero fuel mix. Hydrogen accounted for around 40% of the total thermal input, meat & bone meal (MBM) and glycerine accounted for the other 60%. However, MBM and glycerine are expensive and currently not used, whereas waste derived fuels are. Further work is needed to optimise the fuel mix to increase the use of biomass (in waste derived fuels) and optimise the amount of hydrogen.

The new trials would aim to increase the use of lower cost, higher biomass waste derived fuels and not just replace coal with hydrogen. The main aim of the test is to assess if hydrogen can help overcome an established maximum thermal substitution rate of lower grade waste derived fuels. In doing so, the trials could lead to use of hydrogen alongside higher proportions of waste derived fuels today, keeping feedstock costs low and maximising the impact of small quantities of hydrogen. This would reduce the overall cost of CO_2 avoidance. Furthermore, with hydrogen enabling the increased content of biomass in the fuel mix, and with CCS for the reaction emissions, a cement site could provide negative emissions to the UK system.

Further trial of hydrogen will be carried out over a longer period, with the aim of the demonstration to compliment further work suggested in the previous trial and realise emissions reduction sooner. The stream 2B scope would consist of:

- Further detailed engineering works for the decompression skid
- Review of existing operational procedures and assign new key measurables
- Perform 12 trials blending H_2 into the main burner offsetting currently used coal and supporting the increased use of waste derived fuels. H_2 blends would be from 1.5% to c.12% by thermal input

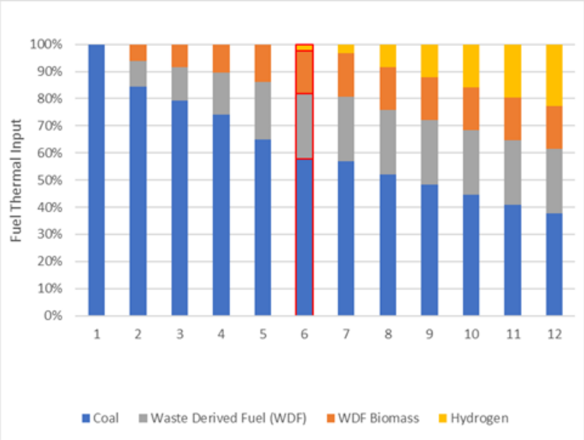

Figure 11 – Cement works suggested H_2 trials

4.2. Engineering Design

4.2.1. Hydrogen Production

The full engineering concept design for the hydrogen production facility up to output from the electrolyser has been developed. It contains details of site integration, process design, steam and electricity supply, site layout and regulatory requirements.

The SOE system is comprised of 9 stack modules, with peak power rating of 128kWe per module but a normal operating power of c.108kWe (975kWe total). Steam at 180ºC and 9barg will be supplied to the electrolyser and used directly by the stacks to produce hydrogen. The H_2 production facility will also contain an E-house that will house the power electronics and AC-to-DC conversion equipment. The e-house will be supplied at 415V AC and the electrolyser can draw a peak current of 800A. Two existing 3.3kVAC supplies rated at 350A each have been identified as the potential supply to the new facility. These were the supplies to the decommissioned electrolyser that was located at the site. The Process Flow Diagram (PFD) in Figure 12. highlights the flow of gases and liquids into and out of the electrolyser and compression system. The accompanying mass balance is presented in Table 5.

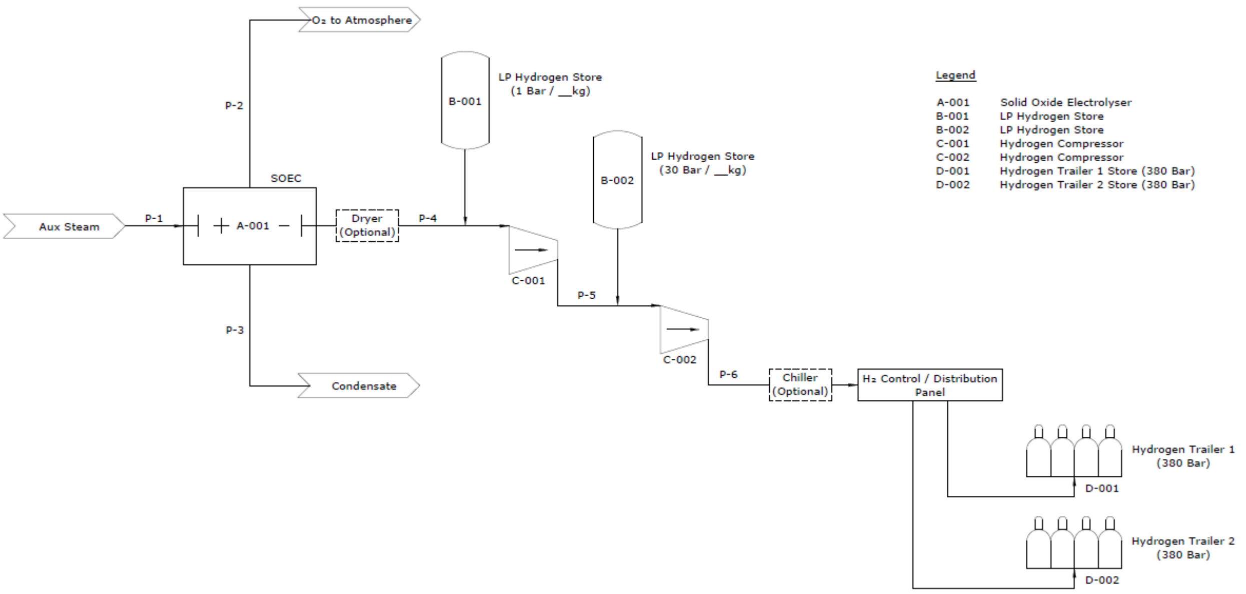

Figure 12 - PFD New Hydrogen Production at Heysham 2 including bottled supply for purging electrolyser at start-up

Table 5 – Hydrogen Production Mass Balance

Stream Number	P-1	P-2	P-3	P-4	P-5	P-6
Description	Aux Steam Feed	O_2 Outlet	H_2O Outlet	SOEC H_2 Outlet	H_2 Product 1st Stage Compression	H_2 Product 2nd Stage Compression
Temperature (°C)	180	130	40	40	15 - 20 *	15 - 20 *
Pressure (barg)	9	0.01	1 - 5	0.02 - 0.04	30	380 430
H_2 (kg/h)	-	-	-	28	28	28
O_2 (kg/h)	-	350 #	-	-	-	-
H_20 (kg/h)	500	-	250	-	-	-
Total Mass Flow (kg/h)	500	350	250	28	28	28

# 70% oxygen enriched air	* above ambient temperature

An assessment of the steam purity has been undertaken for use directly in the electrolyser and has been found to be acceptable. There is currently enough space on site, and demineralised water costs are included in the LCOH modelling as additional water is required to make-up the existing steam system given steam is consumed in the electrolyser.

It is recommended that as part of Stream 2B:

- A Basis of Design (BoD) document should be developed to capture the design requirements for this new facility prior to commencing design development.
- A wind loading assessment should be carried out on the proposed installation to determine requirements for anchorage, such that toppling and or movement cannot not occur.
- Confirmation should be obtained on whether the proposed quantities of hydrogen that are to be stored at the site will change the COMAH tier rating.
- Consultation with the EA should be undertaken to confirm if the proposed emissions from the new facility will require a revision of the site emissions permit. This is likely to involve hydrogen dispersion modelling. The timeframe currently given by the EA to complete this process is 12 months. This is a conservative estimate and should be started at the earliest point.
- A Biodiversity Impact Assessment should be progressed at an early stage

4.2.2. Hydrogen Compression and Distribution

The hydrogen stream from the electrolyser is at 1-1.05bar which requires compression to 450bar for loading the NPROXX system that operates at 380bar. To do this, two compression units are required coupled with interim storage at the output hydrogen pressure and a second storage unit at 30bar. These units are required to ensure a continuous flow of H_2 to the compressors, smoothing out any fluctuations in electrolyser operation.

The below Process Flow Diagram (PFD) details the concept design for the compression and distribution aspects of the demonstrator, based on the 1MW SOE system. The first stage compressor is a reciprocating design, and the second stage is a diaphragm design. Both stages have integrated cooling which ensures the H_2 outlet temperature is within 15°C of ambient.

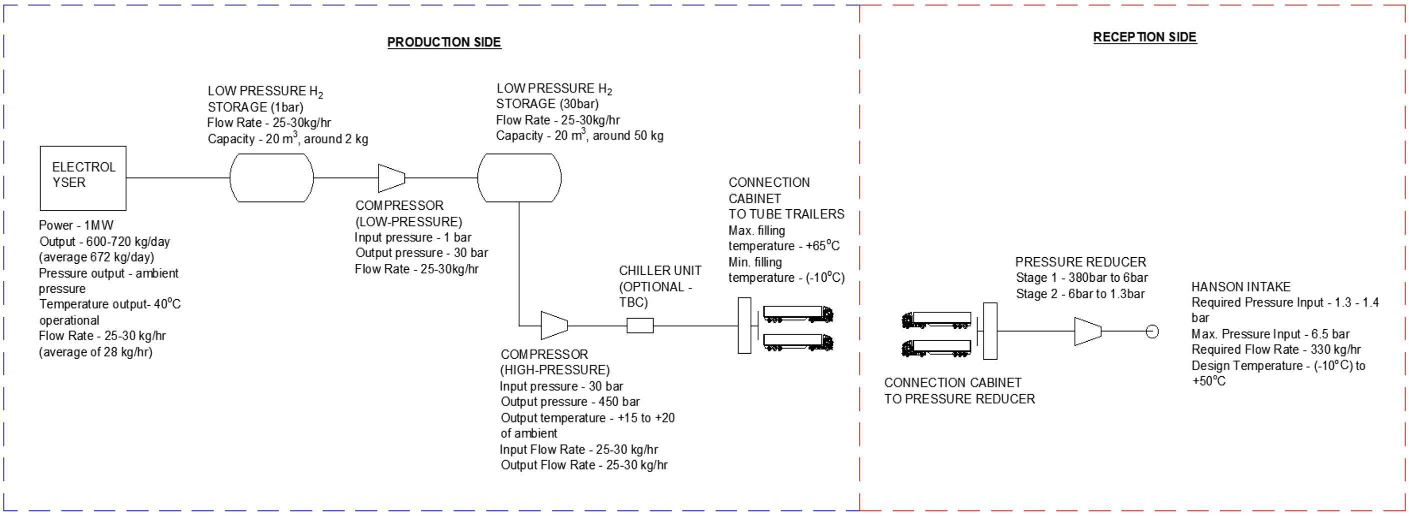

Figure 13 - Process Flow Diagram for Compression and Distribution

Currently a bespoke compressor system is required due to the combination of low H_2 flow rate (c.28kgH_2/hr) and compression ratio. Most commercially available systems operate with input pressure of 20-30 bar, aligning with existing SMR, PEM and Alkaline electrolysis production routes vs the c.1bar output pressure of the SOE. Two of 10 engaged providers have indicated that this is feasible and quoted for the system design and manufacture. An optional chiller system is included to manage the loading temperature of H_2. The temperature of the NPROXX cylinders increases with loading, so a chiller can be used to ensure continuous flow at high ambient temperatures. Only at temperatures close to 40ºC would the system be required.

Three trailers are required for the system to ensure continuity of supply at the Asphalt or Cement end use site. At the end use site, a pressure reducing station is required to deliver hydrogen to the burners at the desired pressure and flow rate. The first stage pressure reduction would take the H_2 from 380bar to 6bar, before a second stage reduces this further to the burner input pressure range of 1.3-1.4bar.

4.2.3. Hydrogen End Use

The system boundary at the end use site begins post the pressure reduction skid, at a H_2 supply pressure of 1.3-1.4bar. Civil, mechanical, electrical and process engineering design has been reviewed from the trailer reception area through fuel delivery and burner design.

Asphalt

Figure 14 presents the general layout for conversion of a single drum kiln at an asphalt site, noting the main engineering concerns are pressure reduction skid, pipelines and burner design.

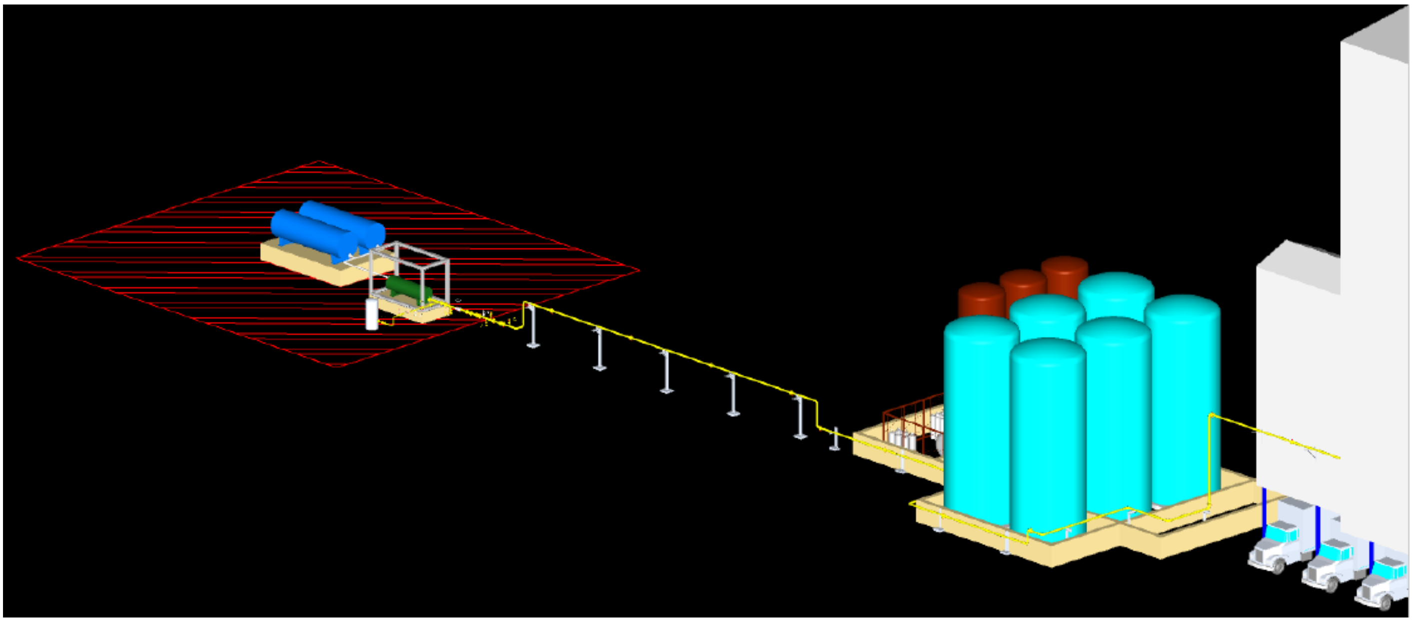

Figure 14 - General Layout of Asphalt Fuel Switch

Asphalt production requires intermittent thermal demand, similar to just in time (JIT) manufacturing. Instantaneous throughput of the H_2 skid can be large and disproportionate to the total daily demand. A single burner is rated at c.10.5MW, which would require a flow rate of 267kgH_2/hr for continuous operation. Furthermore, there are differences between batch, continuous and semi-continuous burner designs, with batch burners fuelled by H_2 at the lowest TRL of the three processes. Positive discussions with OEMs indicate that a H_2 burner for trial running could be available within the timeframes of the project.

Civil engineering work will be required for the pipeline, de-compression skid and hydrogen trailers. The pipeline will require concrete pads for all support stanchions, a concrete hard standing will need to be constructed to situate the pressure reduction skid and trailers within a 'hydrogen compound'. The hydrogen compound will require safety fencing as well as armour barriers in the highest traffic risk areas. The H_2 pipeline will conform with relevant standards for material selection and design. 316L stainless steel is considered to be the material of choice given its resistance to hydrogen embrittlement when transferring hydrogen.

Control system modifications will be required on site to ensure compatibility with hydrogen. New safety equipment and instrumentation will be required to connect to the existing programmable logic controller (PLC), which will undergo software changes. The uninterrupted power supply (UPS) will be reviewed, and upgrades made where appropriate. Electrical supplies to the pressure reduction skid are needed for instrumentation (24V) and control (220V).

Cement

The pressure reduction skid design will be applicable for both the asphalt and cement plant demonstrations given the trials planned and the flow rates required. The skid will deliver 30-330 kgH_2/hr. Fuel feed into the kiln is still under review, either using a lance as per other trials or via the existing fuel transport lines.

The majority of the cement works engineering design for hydrogen burner has been previously undertaken. There is an existing laydown area for trailers and pipeline with a control valve system that can be used to feed hydrogen to the kiln.

4.2.4. Levelised Cost of Hydrogen

Total costs of delivered hydrogen have been calculated for the demonstrator in 2025 and for a future c.100MW scale SOE plant in 2035. A comparison of nuclear backed SOE costs up to 30bar compression vs other technologies has also been undertaken. For technology comparisons, "BEIS Hydrogen Production Costs 2021" have been used for electrolysis and reforming LCOH. Nuclear connected electrolysers are considered to have 0 carbon emissions and so no associated carbon tax. Electrolyser utilisation is maximised to reduce CAPEX impact.

Assumptions

Table 6 - Levelised Cost of Hydrogen Assumptions

Variable	Value (£2022 prices)		Source
	2025	2035	
SOE Utilisation	90%	95%	Ceres
SOE System Life	c.30 years		
SOE Stack Life	45,000hrs	90,000hrs	
Discount rate	10% (Except SMR @ 6%)	6%	DESNZ, EDF, NNL
Compressor Life	c.30 years		Suppliers
NPROXX Container Life	>50 years		NPROXX
System build time	2 years		Assumption
Offshore Wind LF	51%	60%	DESNZ Elec. Gen. Costs 2020
Grid Carbon Intensity, gCO_2/kWhe	120	18	Greenbook
2022 Prices			
Wholesale Elec Price (£/MWh)	135	55.6	Market for 2025, EEP Reference Scenario for 2035
Wholesale Gas Price (p/therm)	125p (300p for 2022)	72.3p	2025 Futures Market & Greenbook (+2022 historical)
Carbon Price (£/tonne)	£80	£326	UK ETS & Greenbook
Carbon T&S	£21.2		Best guess based on ETI UKSAP, ESME, Uniper and ETI Costain PBD Axis

Demonstrator LCOH – 2025

The projected LCOH is dominated by electricity and CAPEX of the production facility. To meet the 2025 deadline, bespoke, in-house manufacturing of the electrolyser and its' supporting systems is required, with very high CAPEX vs projections for mass production (c.GW scale p.a). Through life stack replacement costs are also high driven by the same manufacturing limitations. Low flow rates and high compression ratio requirements drive high compressor CAPEX per kW H_2 HHV capacity, with significant potential cost reductions with scale.

Electricity prices are currently volatile and future projections uncertain. A best view of £135/MWhe has been used for the demonstrator however prices could be between £110-160/MWhe or even outside of this range.

The trailer logistics are also not optimised for high trailer utilisation or long-term haulier agreements. Haulier costs could reduce by 50% with long-term contracts and even further with fuel price reductions.

Commercial Scale (c.100MW) LCOH – 2035

With further technology and manufacturing improvements, economies of scale, and lower electricity prices, a future commercial plant could realise large cost reductions, with still further potential. Electrolysis CAPEX will reduce significantly and fixed OPEX an order of magnitude reduction. DESNZ EEP data has been used for 2035 wholesale electricity price at c.£55/MWhe. With a 100-fold increase in flow rate, compressor CAPEX could realise a c.7-fold cost reduction.

Transport CAPEX has not been reduced as the product is currently commercially available and manufactured for multiple customers. With increased manufacturing scale, these costs could reduce.

Discount rates can have a large impact on costs. For the future plant, a 6% discount rate has been used vs the 10% used for the demonstrator. We would expect that for a commercial plant operating in a mature 2035 hydrogen market and benefitting from the investments and internationally subsidies gone before it, investment risk is lower and hence projects should realise lower discount rates. However, this is uncertain and project dependent.

LCOH for the 2035 end-to-end system is now electricity and transport cost dominated. Any technology using electricity will have to consider the lost opportunity cost of selling into the electricity markets vs using for electrolysis (other than during periods of curtailment, however this relies on reform on how renewable generators are reimbursed to be constrained off to incentivise use of electricity for other means such as electrolysis). As such, electrolysis technologies LCOH will be inherently driven by electricity market (& Power Purchasing Agreement (PPA)) prices rather than technology production costs.

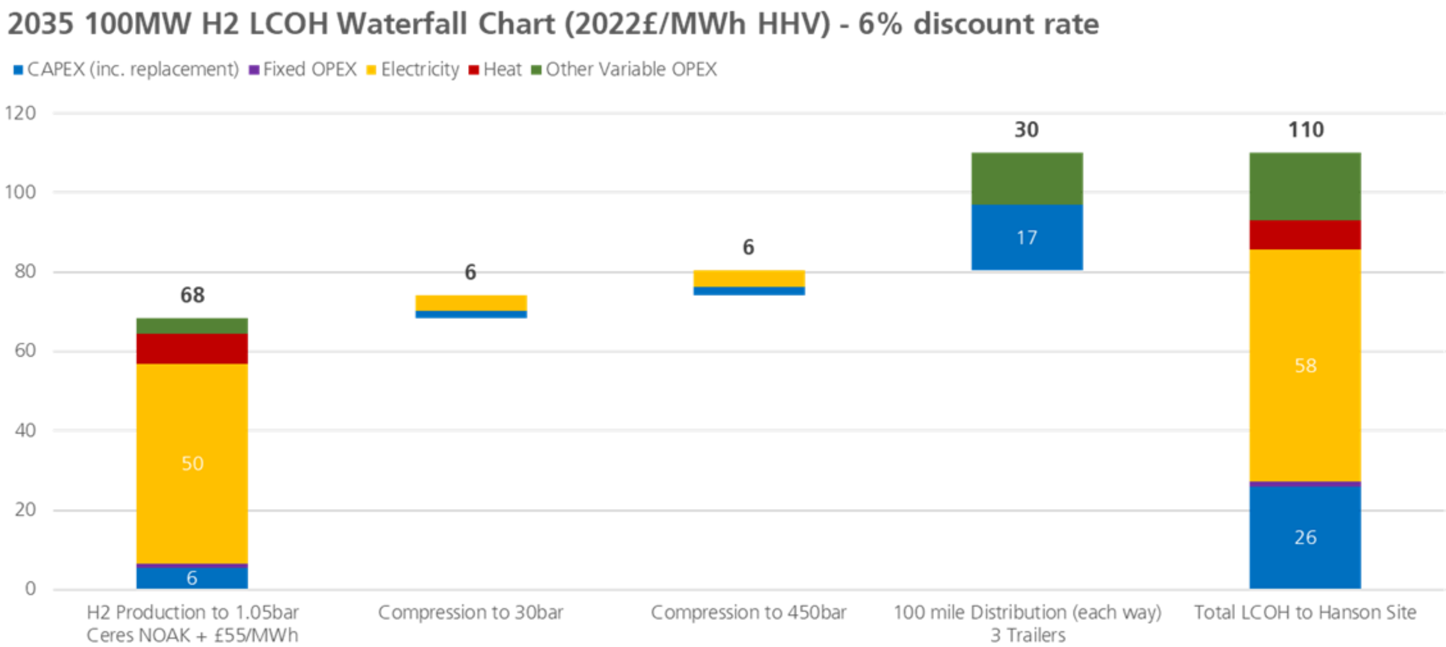

Figure 15 - Future 100MW Commercial Scale SOE Plant

Transport

Costs to transport hydrogen c.100miles by trailer including the second stage of compression are in the order of £30-40/MWh HHV under the assumptions made in this project for a 100-mile return trip. Further optimisation and cost reductions could lead to prices in the order of £20-30/MWh HHV which aligns with other studies to date (9). This compares with a wide range of costs for a future national transmission, dependent on new build or retrofit of c. £7- £18/MWh HHV. However, these costs do not include distribution piping from the national network to the industrial site. For a site c.50miles from the national network, this additional CAPEX could be c.£12m for the hydrogen volumes considered in this study, adding c.£90/MWh

HHV, however this is not optimised and does not consider other off takers, larger volumes or a closer connection point.

For the distances considered, trucking via type IV containers is the same order of magnitude of costs for a national network, although slightly more expensive. However, these can be delivered today, offer flexibility of supply, reduce upfront CAPEX investment required in pipelines, and act as on-site storage.

Technology Comparisons

A comparison of coupling nuclear with SOE technology and compressing to 30bar vs competing technologies such as PEM, Alkaline and reforming processes has been undertaken using the assumptions in Table 6. This analysis indicates that a future commercial plant could be cost-competitive with competing technologies that experience similar cost reductions. Furthermore, a nuclear backed plant would not require a grid connection to achieve high utilisation and provide reliable supply to industry, whereas a renewable connected project would, along with the associated carbon taxation and system costs. System costs have currently been excluded from this analysis.

4.2.5. Levelised cost of Abatement

The economic Key Performance Indicator chosen for benchmarking the viability of fuel switching to hydrogen is the cost of reduced CO_2 (CORC). This KPI compares cost of produced product (COP) and specific CO_2 emissions (*e*) with and without the implementation of H_2 fuel switching.

Equation 1: *Cost of reduced CO_2 (CORC)*

$$CORC = \frac{COP_{with\ H_2} - COP_{without\ H_2}}{e_{without\ H_2} - e_{with\ H_2}} \left[\frac{£}{tCO_2}\right]$$

Product specific CO_2 emissions only include process and fuel emissions, whereby emissions from electricity have been discounted under the assumption that sites operate using green electricity, either directly or through the purchasing of Renewable Energy Guarantees of Origin (REGO) certificates.

Cost of produced product (COP) includes CAPEX (C_{CAPEX}) and fuel (C_{fuel})

Equation 2: *Cost of produced product (COP)*

$$COP = C_{CAPEX} + C_{fuel}$$

Asphalt Economics

The reference asphalt plant is a batch asphalt plant, with a throughput theoretically calculated assuming a 100% H_2 fuel mix can be achieved when receiving at 700 kg of H_2 per day.

Table 7 Technical data and assumption for economic scenarios

Plant technical data	Unit	Reference Plant
Asphalt production	$t_{asphalt}$/day	347
Thermal energy consumption	kWh/$t_{asphalt}$	79.6
Direct CO_2 emissions	$kgCO_2/t_{asphalt}$	21.3
Fuel type (reference scenario)	-	PFO
Fuel emission factor	$kgCO_2$/kWh	0.268 (gross) (net 0.28527)

Table 8 Economic data

	Unit	Value	Comments
CAPEX (C_{CAPEX})	£	1,105,000	Hydrogen facility and construction (unloading system, skid and burner)
CAPEX (C_{CAPEX})	£/$t_{asphalt}$	0.63	30 years facility lifetime, 6% discount
PFO fuel mix (C_{fuel})	£/$t_{asphalt}$	7.27	Using greenbook costs 2035
H_2 fuel mix	£/$t_{asphalt}$	10.34	Includes generation and transport

An economic assessment can be made from the information provided in Table 7 and Table 8.

Table 9 Economic assessment

Parameter	Unit	Δ
$COP_{with\ H2} – COP_{without\ H2}$	£/$t_{asphalt}$	*3.70*
CO_2 reduction ($e_{without\ H2}$- $e_{with\ H2}$)	kg CO_2/ $t_{asphalt}$	22.7
CORC	£/t CO_2	163

The cost of CO_2 avoidance appears high when compared with CCS techniques, however CCS needs to be further explored for asphalt system as compatibility with ‘standard’ system could be difficult due frequently varying fuel combustion. Fuel switching to alternative fuels such as hydrogenated vegetable oil (HVO) could currently cost 40% less than hydrogen fuel switching, however unlike hydrogen HVO would still result in scope 1 CO_2 emissions from the process, albeit biogenic. HVO supply can in some cases be volatile, in addition to this ethics around it’s land use for production need to be further explored.

It is clear from the analysis that the cost of hydrogen heavily impacts the CORC value, if hydrogen transmission could be carried out via pipeline then the CORC value could reduce by 25-30%.

Cement Economics

The reference Cement is similar to a plant used in a previous report, plant design is based on Best Available Technique (BAT) which is described in the European BFREF Document.

Table 10 Technical data and assumption for economic scenarios

Plant technical data	Unit	Reference Plant
Clinker production	t $_{clinker}$/day	3,000
Thermal energy consumption	GJ/t $_{clinker}$	3.0
Direct CO_2 emissions (fuel & raw materials)	kg CO_2/t $_{clinker}$	806 (270 + 536)
Fuel type (reference scenario)	-	65% Coal firing, 35% Waste
Fuel type (test scenario)	-	30kg H_2 injection to overcome waste firing MAX. Increase waste fuel up to 40% substitution.
Coal emission factor	kg CO_2/GJ	90
Recycled fuel emission factor	kg CO_2/GJ	55

Table 11 Economic data

	Unit	Value	Comments
CAPEX (C_{CAPEX})	£	1,105,000	Hydrogen facility and construction (unloading system, skid and burner)
CAPEX (C_{CAPEX})	£/t $_{clinker}$	0.08	30 years facility lifetime, 6% discount
100% coal fuel mix (C_{fuel})	£/t $_{clinker}$	8.12	*Based on main burner fuel only. Coal £200/t and Waste £12/t*
H_2 fuel mix	£/t $_{clinker}$	8.34	Includes generation and transport

An economic assessment can be made from the information provided in Table 10 and Table 11.

Table 12 Cement Economic assessment

Parameter	Unit	Δ
$COP_{with\ H2} - COP_{without\ H2}$	£/t $_{clinker}$	0.29
CO_2 reduction ($e_{without\ H2} - e_{with\ H2}$)	kg CO_2/ t $_{clinker}$	6
CORC	£/t CO_2	51
CORC (including ETS savings*)	£/t CO_2	-24

* UK ETS scheme costs: £75/tCO_2

The cost of CO_2 avoidance appears attractive when using hydrogen as a fuel enhancer for waste fuel that contains a proportion of biomass, the main aim of the demonstration is to test this theory. CORC of CCS within cement is better understood and previous studies suggest that it should lie in the range of 50 to 150 £/tCO_2. When assessing hydrogen as a fuel enhancer it's clear that even small amounts of hydrogen can significantly increase the overall fuel mix net calorific value (NCV), a minimum threshold for NCV of the main burner fuel mix is well understood within the industry. Therefore, small amounts of hydrogen could prove to be a very good fuel enhancer allowing more than a 5% increase in waste fuel as proposed in the cost analysis.

Similarly, to asphalt CORC is dependent on the cost of hydrogen, however as hydrogen is proposed to be used as an enhancer with another fuel the costs aren't linear, CORC can be cost neutral based on a 20% reduction in hydrogen costs.

When considering CORC, including cost avoidance from UK ETS, the overall value becomes negative. In this case CORC is similarly non-linear, if UK ETS costs are considered then up to 42 kgH_2/h could be used while maintaining the overall CORC as cost neutral.

4.3. Overall Schedule

A detailed schedule for the demonstrator phase of the project will be finalised as part of the Stream 2B application. Our high-level initial schedule estimate is split into eight main phases. The indicative plan is:

- **May – Oct 2023:** Confirmation of engineering design and finalisation of engineering packs across production, delivery and end use. Supply chain preparation: equipment specifications, supplier contracts. c.6 months.
- **Nov 2023**: DESNZ November Stage Gate Review.
- **Nov 2023 – Mar 2024:** Equipment and construction services contracting, concurrent site planning works, clearance and permitting, and end of demonstration plan finalisation. Mobilising project team and commencing early works. C.3-6 months.
- **Mar - Aug 2024:** Factory Acceptance Testing (FAT), continued construction and commissioning (production and end-use). Trial planning defined c.6 months.
- **Sept – Nov 2024:** Equipment deliveries, assembly (pipework + electrical), cold commissioning, hot commissioning, trial running and operations c.3 months. Post-trial development planning and future commercialisation.
- **Dec 2024 - Jan 2025:** Continued trials, results analysis, report preparation and dissemination, business plan and commercialisation pathway refinement c.2 months.
- **Feb – Mar 2025:** Decommissioning/ongoing operations planning c.2 months.
- **Mar 2025 – Dec 2028:** Extended demonstration phase subject to commerciality of ongoing H_2 supply (market rate for net zero hydrogen or business support)

Overlap between phases is required to meet the 22-month timeline required by the Stream 2B competition. There is some contingency built into this indicative schedule but also significant risk especially around equipment procurement which requires early procurement and securing of manufacturing and delivery slots.

Furthermore, the installation and trial running of the equipment must work around the plans for Heysham 2 maintenance schedules and Hanson's asphalt and cement operations. Managing this will be paramount to the project's success. Steam can be supplied from either unit at Heysham 2, so maintenance impact is considered low. Hanson's asphalt operations are non-continuous but cement operations outside of planned maintenance generally are.

4.4. Procurement

There are currently lasting supply chain issues post the global pandemic and with the ongoing war in Ukraine that may cause issues to procuring items in a timely manner for the demonstration project. Long lead time capital items include the electrolyser and the NPROXX storage and transport system given current demand for H_2 technology. As these two organisations are supporters of the project, identification of issues and prioritisation of resource to the project can be managed and alternative options assessed.

4.4.1. Electrolyser

At this stage in the project, Ceres have indicated that manufacturing and delivering the 1MWe system within the timeframes of the IHA project are very challenging and it is unlikely that the deadlines will be met. Conversations between parties are still ongoing, but alternative manufacturers of SOE systems have also been engaged. Initial conversations indicate that delivery of a similar 1MWe system could be achieved within the timeframe, subject to early tendering and procurement.

4.4.2. Compressors

Lead times for the compressor systems vary between suppliers with offerings between 12 and 20 months. Contingency should be built into this to ensure that the demonstration can operate for as long as possible within the timeframes of the innovation funding.

4.4.3. Storage and Transport Solution

Similar to the compressor systems, the NPROXX trailers currently have an 18-month lead time. Early procurement would be required to meet the project timeframes.

4.4.4. Burners

OEMs engaged through the feasibility study have indicated that H_2 ready burners for use in batch asphalt operations are at a low TRL and will require a further R&D. A dual fuel burner capable of using hydrogen, oil and LPG could be delivered within 9 months of commencing work given the trial ethos of the demonstration and there is interest to be ready to test at an operational asphalt plant in the UK. However, there is operational risk to Hanson's site if using an untested burner and this must be mitigated before any burner will be used on site. Conversely, hydrogen burning within cement kilns has been done before and further trials offer a low risk, high reward scenario. Keeping both these options open for demonstration will ensure any realised risk in procurement over the 2 years in the asphalt space can be alleviated by use of hydrogen at the cement works.

4.4.5. Procurement risk

As presented, there are multiple key pieces of equipment that have lead times that could have a significant adverse impact on the demonstration project timings. Given the November 2023 stage gate review for the project, there is real risk of missed delivery by the March 2025 window. It is unlikely that expensive equipment would be procured prior to November 2023 and 18 months would be past the March 2025 deadline. Successful demonstration requires early engagement with suppliers and a consideration that equipment supply is outside the control of the project team. As such, a contingency plan should be in place to ensure project objectives are achieved in the event of overruns past the March 2025 deadline.

4.5. Risk Management

A risk register will be created at the start of the project through engagement across all parties, including DESNZ. This register will be an evolution of the feasibility study risk register, with many of the same risks still applicable. Key major project risks for the demonstrator are:

- **Procurement**:
  - Long Lead Time items. Equipment is not delivered in the required timescale, impacting project schedule
  - Issues with sub-contractors delivering slowly or at a poor quality. Impacts project schedule
  - Sub-Contractor cashflow difficulties, due to difficulties with DESNZ payment terms. Deterioration in relationship with sub-contractors.
- **Technical**:
  - Burner development is delayed. Impact on project schedule.

4.6. Regulatory Requirements

4.6.1. Health and Safety

A HAZID study at the production site and a Concept Hazard Assessment (HS1) at the end use site were undertaken during the feasibility study phase, one covering the production and compression system design and the other the decompression and end use design. Both studies provided an overview of key hazards and risks, with recommendations on how these should be considered and mitigated for the demonstration phase.

Production and Compression

Risktec were subcontracted to facilitate the HAZID workshop and identified 31 recommendations for the next phase of the project. Discharge locations, hydrogen detection equipment, leak detection, HSE warning signage, passive non-return features, lightning protection and supply route redundancy were all identified and considered by this assessment.

End use

A HAZID and Hazard and Operability Study (HAZOP) has previously been undertaken for use of hydrogen within cement. Key findings included the requirement for new flame temperature monitoring as flames >70% hydrogen input by volume are invisible, and current systems will not identify when the burner is running. In the event of a failed flame, there must be a software control that will automatically enable the plant’s emergency stop, following this event the system must be prevented from starting without purging the plant of fuel that has not combusted. Burner modifications and visibility of the pressure reduction skid should be integrated into the site’s current control system.

Stream 2B considerations

For both production and end use, further studies within the demonstration phase must be undertaken to ensure health and safety risks are understood, logged and mitigated. The following will take place at both ends of the hydrogen end-to-end concept:

- HAZID (HS2) for the end use site(s)
- HAZOP – Hazard and Operability Study
- DSEAR assessments
- Confirmation of COMAH limits and requirements
- Review of PSSR
- Review of impact of process maloperation

- Risk assessment of potential disruptive failures leading to “missile” generation that could challenge existing plant integrity
- Design and installation of safety equipment such as trips, alarms, fail safe valves, isolation, venting and emergency lighting.

For both production and end use, safe operating documentation will be created, and personnel provided with the right training to understand the risks, regulation and control measures in place when working with hydrogen.

4.6.2. Planning Permissions

At the Heysham production site, hydrogen venting will require a stack of currently unknown height. Small quantities of hydrogen and nitrogen will be vented during purging and start-up of the electrolyser. There may be a requirement for planning permission if the stack is above the height of permitted development on site under the Town and County Planning (General Permitted Development) (England) order 2015. No new building can be higher than 5m if it is within 10m of the curtilage boundary. In all other cases, the height is restricted by the height of existing buildings. If planning permission is required, this may take 8-12 weeks following application. This process is well-understood by the Heysham site.

For the asphalt site, the scale of equipment and required modifications are small, and so planning permission will likely not be required. The cement works site has previously trialled hydrogen, so again planning permission will not be required.

4.6.3. Environmental Permitting

Production

Dispersion gas modelling is required to understand the flow of a hydrogen gas plume from the site. This could impact the environmental permitting as well as the ATEX rating requirement of equipment not within the hydrogen production compound. Safe discharge locations are to be identified using the modelling and will further inform the general site layout.

End use

Studies reviewed to inform the feasibility study indicate a change in the combustion exhaust gases when burning H_2 due to increases in flame temperature. Studies observed a 20-30% increase in nitrous oxide emissions (NOx). As part of demonstration, spot measurement of NOx should be undertaken. No changes to the permit conditions are to be expected, however the process description will need to be updated on the permit to include the use of hydrogen and LPG as a fuel (LPG for blending).

Asphalt sites are considered as small emitters under the ETS (Emissions Trading Scheme) scheme with total burner ratings of >20MW but <35MW. This incurs a cost penalty to the site. Hydrogen is not classed as a fuel under ETS, however any other fuels used as part of the demonstration will require a change to the sites’ ETS permit.

5. Ongoing Development and Future Commercialisation

5.1.1. Immediate Post demonstration

The consortium envisages continuing to operate the plant and providing hydrogen to the end use sites if the demonstration has been successful and it is economically viable to do so. This is dependent on ongoing operational cost support such as through the Hydrogen Business Model (HBM). The consortium vision is that the demonstrator would lead to immediate and long-term benefits to Hanson's sites and pave the way for conversion of other sites if it can be shown to continue to operate reliably. However, there are currently limitations of the HBM terms that preclude the demonstrator project:

- Installation must be =>5 MW H_2 HHV
- The end of generation date at Heysham is 2028 +-2years given the current plans for defueling
- It may be possible to continue to operate the electrolyser beyond this date using an alternative low carbon electricity supply

With ongoing support from DESNZ, this demonstrator could have an immediate and longer-term decarbonisation impact utilising hydrogen.

5.1.2. Future Nuclear Hydrogen

This section of the report provides a summary of the output of work package 5 'Future Nuclear Backed Hydrogen'. This work focused on the future development and deployment of nuclear technologies beyond the proposed Hydrogen4Hanson demonstration project, including the economics around the development of future commercial plant, the scalability & replicability of hydrogen production and siting considerations.

Technology and System Development

Development of nuclear reactor technology over the coming decade could result in a different market for nuclear technologies established through optimised modularisation, a mature and resilient supply chain and innovation in regulatory assessment approaches that drive investor confidence and improved economics. This may in turn unlock thermochemical hydrogen production methods and new markets for nuclear power including hydrogen to support industrial decarbonisation and synthetic fuel production, facilitating decarbonisation pathways for hard to decarbonise sectors such as long-haul aviation. There could also be opportunity for direct coupling of the heat from Advanced Modular Reactors (AMRs) to industrial applications such as cement kilns.

Thermochemical hydrogen production processes could be longer term options that should remain under review and be considered for large scale hydrogen production alongside AMR developments. In the meantime, innovation in the use of steam electrolysis with nuclear energy presents a nearer term option.

When considering future siting, hydrogen production facilities located outside the nuclear licensed site, as shown in Figure 16, have the potential to reduce cost and improve maintainability compared to systems located on the licensed site. Reflecting on the nuclear industry's experience working alongside hazardous industry such as chemical production facilities and a shipyard yard at Hartlepool, it is understood the processes and procedures already implemented would be sufficient for hydrogen generation adjacent to Hanson and other industrial sites. The main areas for consideration being hydrogen storage and safety culture changes.

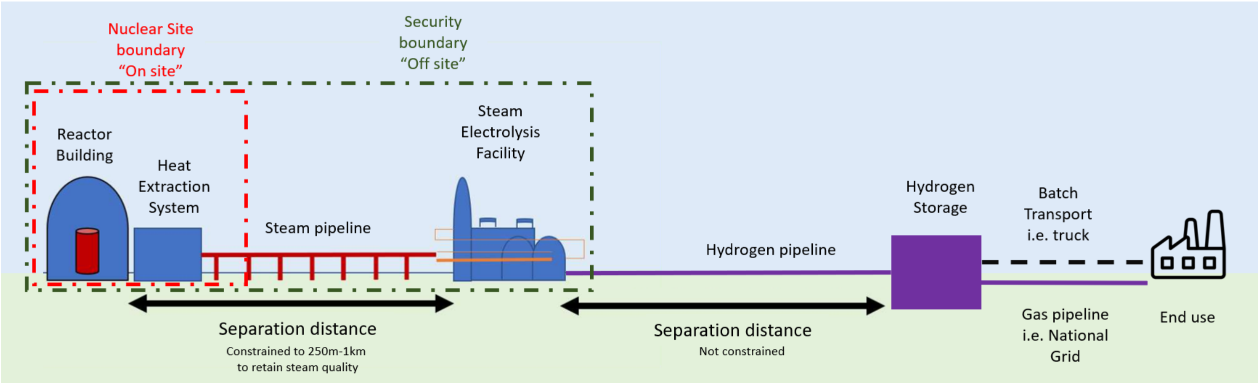

Figure 16-Hypothetical layout of a facility with typical nuclear site plant buildings, including heat extraction system (on site), steam electrolysis facility for hydrogen production (off-site) and transport, storage and end use facilities

Replicability and Scalability

The timelines for nuclear developments and the anticipated ramp up of hydrogen demand in the 2030s aligns well, as shown in Figure 8 earlier in the report.

The total energy demand for hydrogen by Hanson is approximately a quarter of a Rolls Royce Small Modular Reactor (SMR) or 26 of the U-battery AMR systems which, could potentially be sited across the UK near to Hanson sites as shown in Figure 17. When considering siting there is potential nuclear capacity of 83 GW within the UK which shows siting does not need to be a constraint to capacity.

While in the longer term the potential for co-location, especially with AMRs, exists, in the short term it is likely that the supply of hydrogen will be reliant on hydrogen transport and distribution networks. The distribution of hydrogen through the national gas network in the UK, as shown in Figure 18, the majority of which is already compatible with hydrogen, could offer a significant opportunity subject to economic and location considerations. This would require development of hydrogen storage, due to the larger volumes of hydrogen required compared to natural gas. There is significant experience and innovation in hydrogen storage with the UK operating the world's oldest salt cavern hydrogen storage facility in Teesside which opened in 1972. Salt cavern storage potential does not present a limiting constraint for the development of a low-carbon hydrogen network in the UK. It is the most developed form of hydrogen storage with potential for UK salt cavern hydrogen storage capacity of 2,150 TWh.

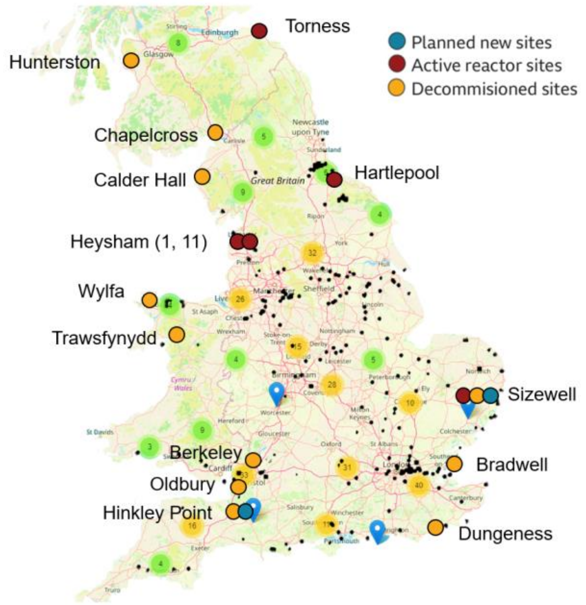

Figure 17-Overlay of potential nuclear licensed sites, current nuclear sites and Hanson Operations. Black dots indicate sites on the Energy Technology Institute 'long list' of potential sites. Pins and coloured circles indicate Hanson operations.

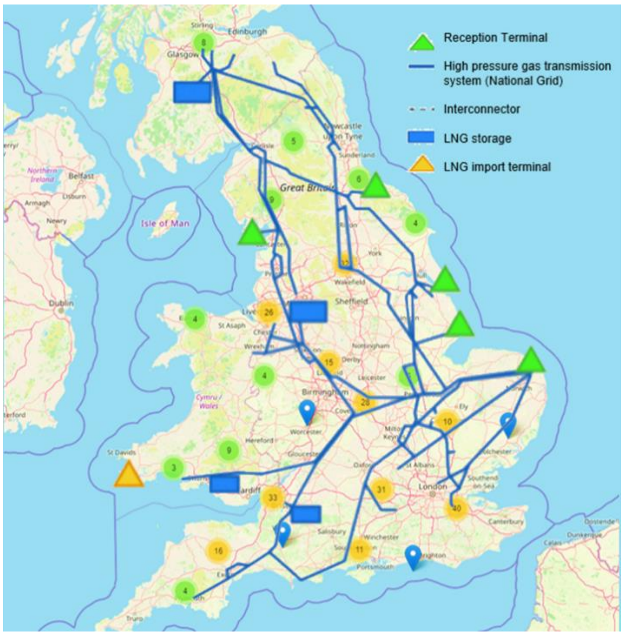

Figure 18-Overlay of National Gas Transmission Service and Hanson Operation. Note orange circled numbers represent a higher density of Hanson operations in that region

Future Hydrogen Economics

The developing technologies of SMRs and AMRs offer the potential for decreases in the Levelised Cost of Hydrogen (LCOH) when compared with coupling GW scale nuclear. The high-capacity factor (percentage of time operating) of nuclear reactors also enables a smaller capacity of hydrogen production technology to produce the same quantity of hydrogen as intermittent renewable technologies. A further decrease in LCOH could be unlocked by adopting novel financing models which are already used on other large UK infrastructure projects.

It is estimated for the LCOH using SOEC technology coupled with a 300 MW_e SMR built under the Regulated Asset Base (RAB) model (with an assumed 6% Discount Rate) hydrogen could be produced at a levelised cost of £2.62/kg by 2035 which could be cost competitive with other solutions, supporting the case that nuclear is an economically viable option for hydrogen production in the UK. The use of heat alongside electricity from the nuclear reactor to improve the performance of the SOEC reduces the LCOH to £2.56/kg. There is also the potential for the oxygen by-product to provide an additional economic opportunity.

As part of full report in Annex 1 a full methodology and results for various scenario are outlined with relevant assumptions summarised, Figure 19 below shares the results from for SMR technology coupling (using BEIS cost and performance assumptions) compared to other low carbon emitting technologies.

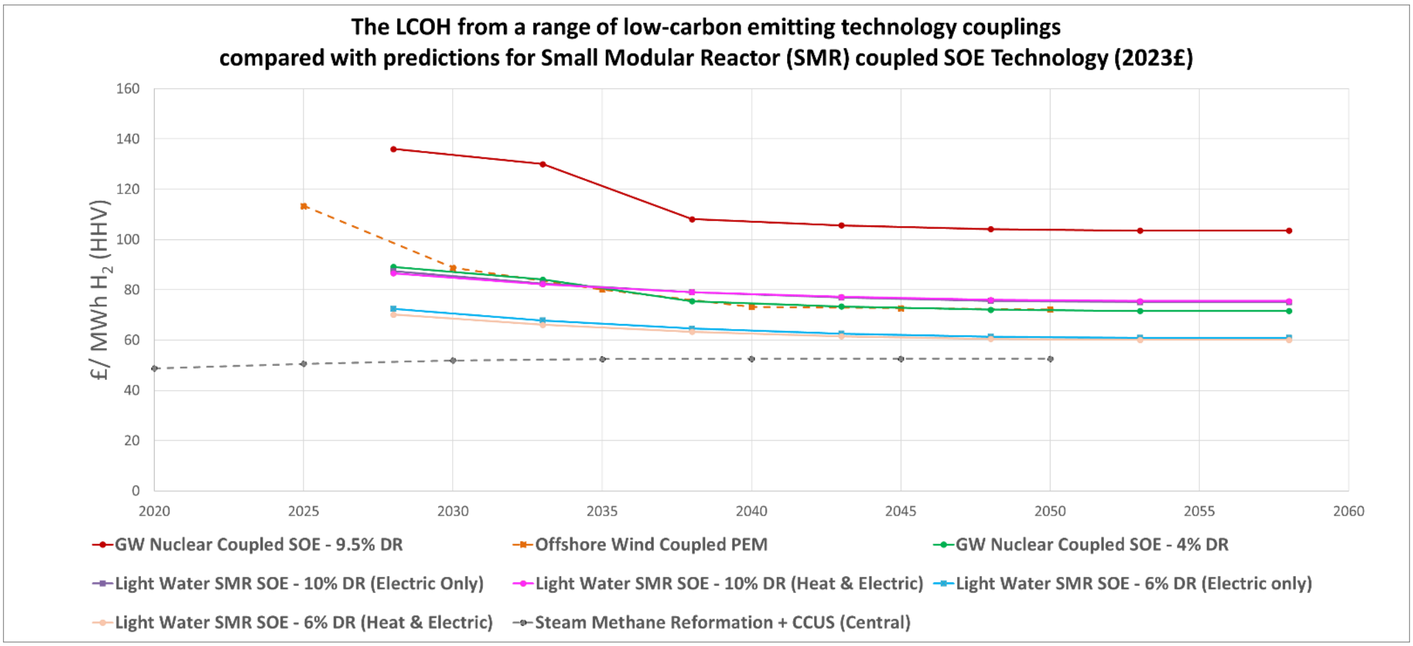

Figure 19 LCOH of SMR coupled SOE technology (BEIS assumptions) compared against a range of low-carbon technology couplings

As a result on this package of work the following recommendations are made:

- Use the learning from the Hydrogen4Hanson project to deliver a stronger evidence base for the role of nuclear enabled hydrogen in a future energy system.
- Further invest in development and demonstration of new nuclear reactor technologies (SMR, AMR, Fusion), hydrogen production methods (steam electrolysis and thermochemical) and coupling technologies to enable nuclear enabled hydrogen production to become a proven viable production technique.
- Continue to collaborate across industries and sectors to understand how hydrogen will be transported and stored in a future energy system.
- Refine understanding on co-location considerations for both nuclear plant and hydrogen generation and also hydrogen storage and end use.
- Further consider the oxygen produced as a by-product of hydrogen production including the economic value of capturing and utilising within industry.
- Investigate the feasibility of Hanson connecting more of its sites to the gas network and the use for hydrogen supply.
- Refine understanding of the cost and performance (including the lifetime) of steam electrolysis cells and coupling of technology to nuclear reactors with 50+ year operation.
- Gain an understanding on how demand of cement and asphalt varies throughout the year and geographically and how this may impact the hydrogen production and storage requirements.

5.1.3. Compression

Work undertaken by Element Energy and Jacobs Consultancy for BEIS in 2018 indicated that compressor size defined by H_2 throughput has a drastic impact on CAPEX (10). Compressor CAPEX cost estimates for this project are of the same magnitude as the presented trend. A 100MW H_2 HHV system could result in a five-fold decrease in compressor CAPEX. Given the requirements for transportation, compression cost savings significantly impact delivered LCOH.

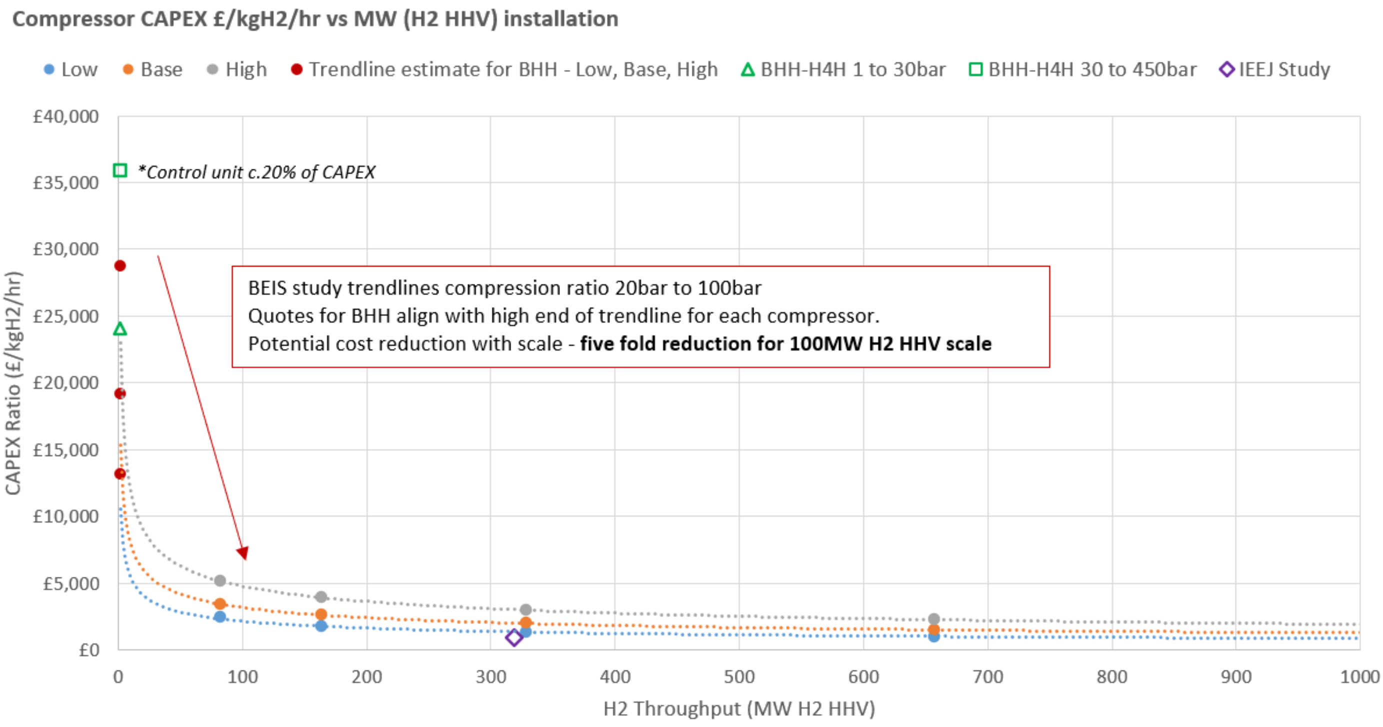

Figure 20 Hydrogen compressor cost reduction curve

5.1.4. High pressure gaseous trucking of H_2

A techno-economic assessment of transporting hydrogen via a dedicated pipeline was also carried out. To construct a new hydrogen pipeline from Heysham to the asphalt facility, the cost incurred will be significantly higher than the cost of using the tube trailer option to transport hydrogen. There is a potential for the cost difference to increase further due to factors such as wayleaves, environmental constraints, etc. The cost difference in delivering hydrogen to the cement facility is comparatively lower, but the tube trailer option would still be more economical considering the significant capital expenditure required for constructing a new pipeline. Other additional requirements for pipeline transportation, including a low-pressure static storage system at the production site and a high-pressure static storage system at the reception site to ensure a constant supply of hydrogen at the required flow rate, and for operational safety reasons, will also add to the costs.

Using existing natural gas pipeline infrastructure to inject and transport hydrogen along with natural gas may be challenging and may require upgrade/replacement as hydrogen is highly reactive and can cause corrosion in pipelines, making it necessary to use specialised material and equipment to transport hydrogen. Under normal conditions, hydrogen can be transported with natural gas, but the presence of moisture or other substances can cause hydrogen to react with these substances and lead to problems. To receive hydrogen at the required flow rate, purity and extract it feasibly at the asphalt facility, significantly higher amounts of hydrogen need to be injected into the natural gas pipeline.

A dedicated national hydrogen pipeline network can reduce costs and overcome mixing challenges, but building it from scratch is costly. Repurposing the existing natural gas pipeline network to carry hydrogen is a more cost-effective solution, with the possibility of reducing transportation costs by about 50 to 60% (excludes metering and other minor charges) compared to the tube trailer transportation option. Additional costs will be incurred for constructing connecting pipelines between the Heysham site and Hanson's facility to the national pipeline network.

5.1.5. Hydrogen in Asphalt

The energy demand for Asphalt is currently provided by fossil fuels and full conversion to hydrogen is being considered for future commercialisation. The minimum amount of PFO (Processed Fuel Oil, currently used fuel in asphalt production) to produce 1 tonne of asphalt is 7 kg. Knowing the calorific value of PFO is 39.8 [MJ/kg], it was calculated that minimum 77.48 kWh of energy is consumed to produce 1 tonne of product. It is important to emphasise that the fuel use in the asphalt burner is not constant, however an estimate of energy consumption had to be implemented to simplify further calculations of equivalent of energy required from other fuels: natural gas and hydrogen.

Water electrolysis using SOE coupled with nuclear provides an attractive proposition of producing hydrogen. LCOH could be as low as 66.5 - 68 £/MWh $_{H2HHV}$ by 2035 according to the model presented in this report and estimations in Annex 1. Graphs in this section show the impact on fuel cost for one tonne of asphalt and when switching to hydrogen is forecast to become cost competitive with existing fuels. Hydrogen cost was considered separately based on BEIS data hydrogen cost for SOE and hydrogen cost based on the proposed solution in Bay Hydrogen Hub project (all of the costs do not include compression and distribution).

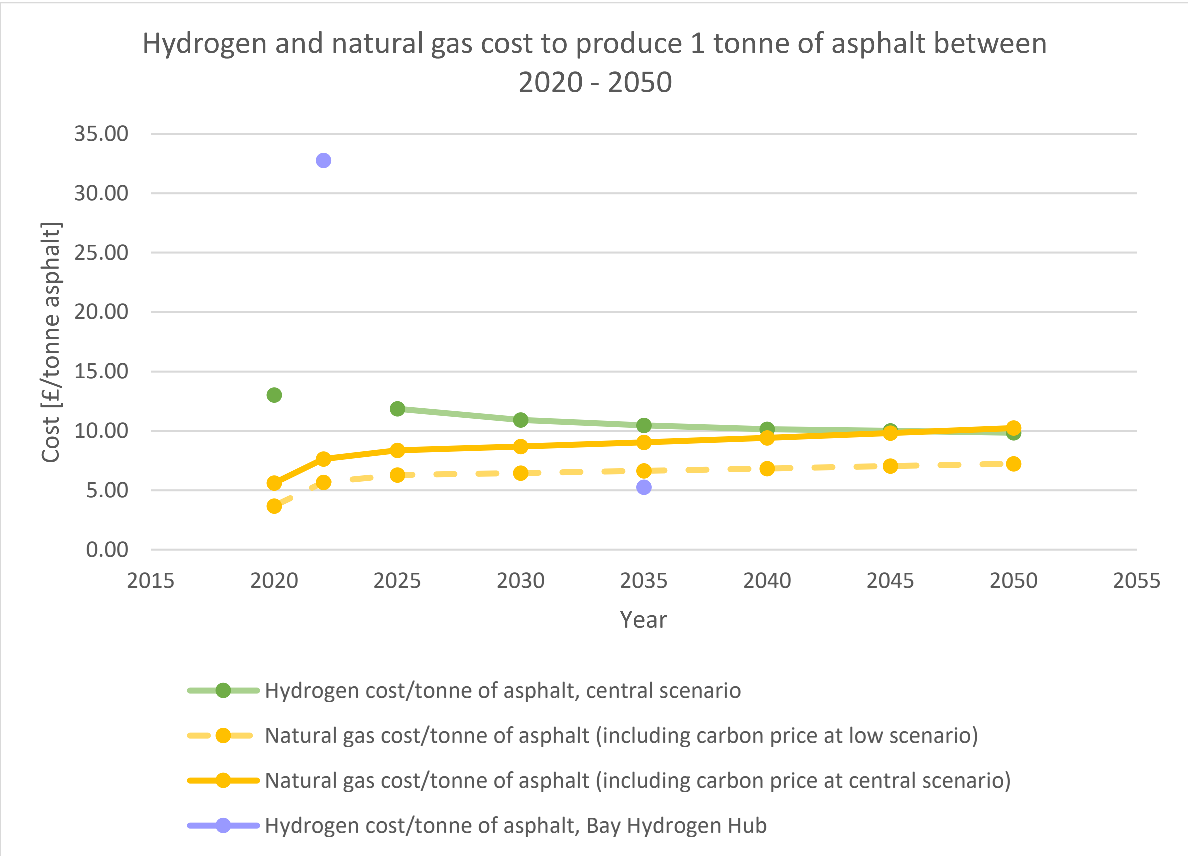

Figure 21 Fuel cost of 1 tonne asphalt production

The analysis shows that even though Natural Gas (NG) replacement by hydrogen is not currently economically viable in asphalt manufacturing, this is expected to change by 2035, and hydrogen could be a lower cost option than NG. In 2035 the difference in fuel costs between NG (including carbon tax at central scenario) and low-carbon hydrogen is forecasted to be less than £1.5/tonne. Moreover, the proposed technology in this feasibility study indicates that further price reductions can be achieved by implementing the Bay Hydrogen Hub proposed solution. By 2035 Levelised cost of hydrogen (LCOH) is expected to be at 68 £/MWh for 100MW system, which could lead to hydrogen being more cost-effective fuel than NG as shown in the Figure 21. This indicates that cost of nuclear-derived hydrogen could decline faster with larger MW scale systems, which then could incentivise faster fuel switching to low-carbon hydrogen for those manufacturers that currently use NG.

NG price was assumed for high scenario included in the Green Book Annex Data 2022. The highest prices were taken due to the current energy crisis that disturbed trade flows and creates long-term uncertainty on the supply prospects in the coming years.

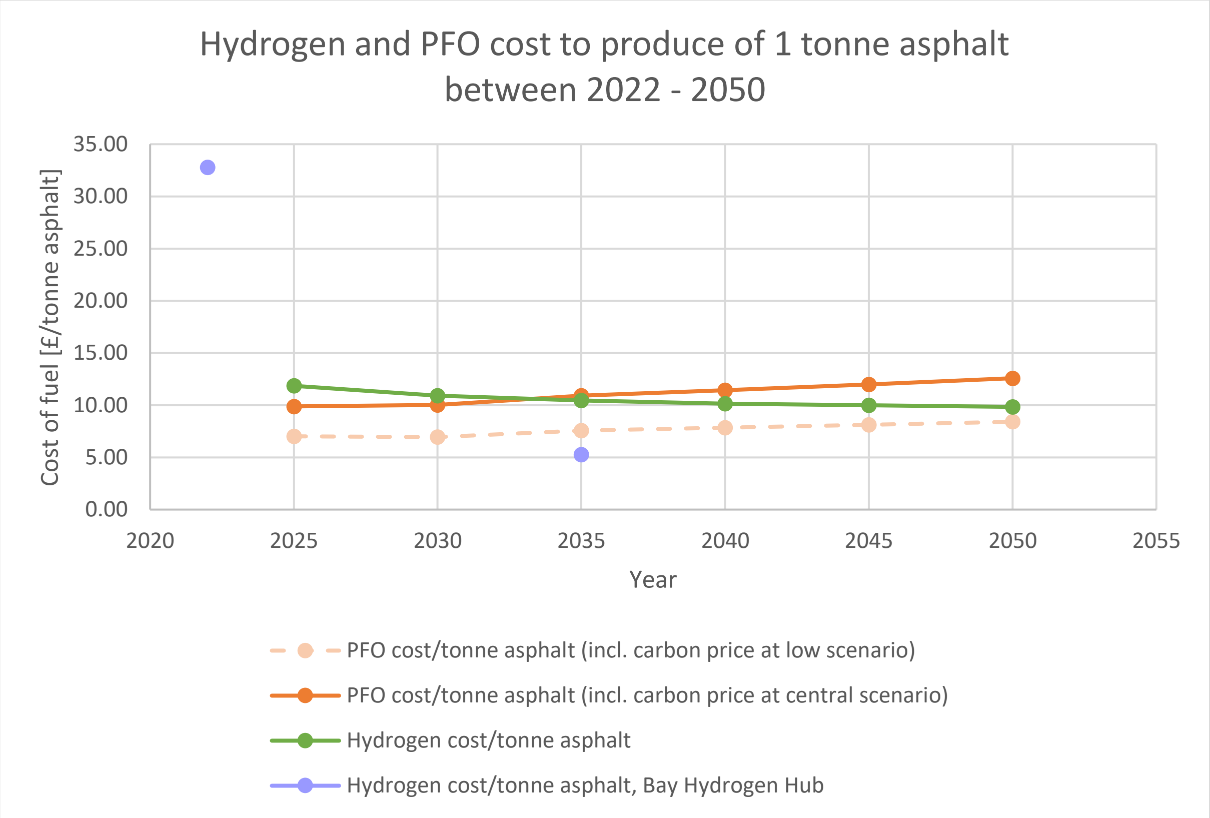

Figure 22 Fuel cost of 1 tonne asphalt production

The PFO price assumed for 2022 has been estimated based on the Gas Oil prices trends (11) – assuming the trends will be identical for both PFO and Gas Oil.

In terms of comparison between PFO and low-carbon hydrogen costs producers of asphalt might not consider hydrogen as an economically attractive option as the cost is difference may vary between 2 and 5 £/tonne asphalt by 2025. However, similarly to the natural gas comparison, the situation is forecast to change by 2035 when the difference in fuel cost between PFO and low-carbon hydrogen will be at the same level or significantly lower. Both Figure 20 and 21 clearly show hydrogen cost production reduction for larger scale electrolysers. Bay Hydrogen Hub data for the cost of hydrogen in 2022 is considered for the 1MW demonstration electrolyser, however for 2035 a 100MW system is assumed, and the difference is significant.

5.1.6. Hydrogen in Cement

Clinker production for cement consumes significantly more energy than asphalt production (c. 810kWh/tonne clinker) and even though it is already common in the industry to utilise net-zero fuels such as waste-derived fuels and biomass, the manufacturers are still heavily reliant on coal as a source of heat. The innovative concept proposed by Bay Hydrogen Hub is to use low-carbon hydrogen along with other low-carbon fuels as a fuel enhancer as the main burner might be sensitive to a fuel quality. For this cost analysis it was assumed that hydrogen would be at 30% of total energy required for clinker production and 70% would be coal that is commonly used in clinker production. Previous trials used 40% hydrogen in a mix with other net zero fuels. Considering the change to coal in the proposed blend a more conservative figure of 30% of hydrogen in fuel mix was applied for an indicative cost analysis.

The analysis shows that competitiveness of low-carbon hydrogen in the fuel mix strongly depends on carbon price. When considering central case of carbon tax level, it seems like 30% coal replacement by hydrogen would be economically viable option by 2040 (with Bay Hydrogen Hub solution this might be achieved at least 5 years earlier), However, if carbon price continues low case trajectory, it would be difficult for low-carbon hydrogen to be competitive, unless hydrogen cost is reduced.

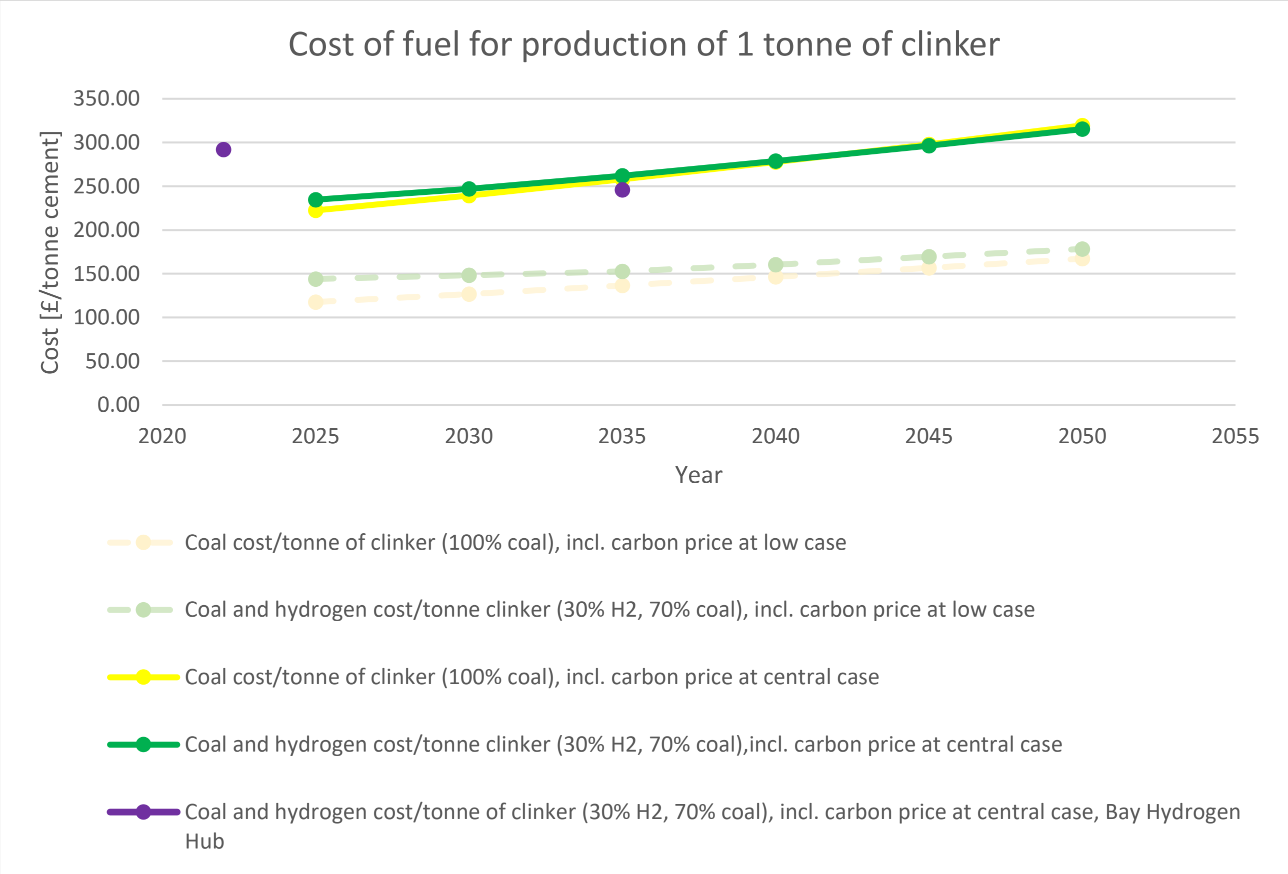

Figure 23 Fuel cost of 1 tonne cement production

The use of hydrogen in cement production has been touted as a potential solution to reduce carbon emissions from the industry. One option would be to use a blend of 30% hydrogen and 70% coal in the cement-making process. However, there will be challenges to implementing this approach, particularly in the current hydrogen price and low carbon price environment. Another approach is to replace coal with waste fuels. In this scenario, hydrogen would play a role as a fuel enhancer rather than a primary fuel, helping to decarbonise the process. Ultimately, a combination of solutions may be necessary to achieve meaningful emissions reductions in the cement industry.

6. Social Value and Benefits

Sustainability, social value and impact, are not an outcome of the work that we do, but the reason and context for it. Shared prosperity and an equitable transition from the carbon-based economy to a sustainable future which retains many of the technological and engineering gains of recent years are essential counterparts. A straight replacement of existing energy sources for carbon free ones will not on its own provide a solution and change of behaviours will also be necessary, alongside measures to adapt to mitigate the effects of global warming. Furthermore, it is imperative that we consider not only the picture in the UK, but that support is given to countries around the world, already experiencing more severe climate disasters than the UK, the effects of global warming. The United Nations (UN) adopted 17 Sustainable Development Goals (SDGs) in 2015, with the UK playing a leading role in their formulation, in particular the central pledge that there must be 'no one left behind'. The production of hydrogen using advanced nuclear and its use in foundation industries has a clear fit with several of the UN SDGs;

- Affordable and Clean Energy (SDG7)
- Decent Work and Economic Growth (SDG8)
- The intention to build resilient infrastructure, promote inclusive and sustainable industrialisation and foster innovation (SDG9 Industry, Innovation and Infrastructure)
- Sustainable Cities and Communities (SDG11, bringing in the use of hydrogen in the production of cement and related products)
- Climate Action (SDG13)
- Good health and well-being from improved air quality (SDG 3)

A project such as this, with its emphasis on sustainable growth and the development of innovative solutions to the key issues facing humankind - and more broadly life on earth, means that there are benefits that will be felt around the globe. Within the UK, increased skills and skilled employment will lead to reducing poverty (SDG1), reducing hunger (SDG2), good health and wellbeing (SDG3) and quality education (SDG4), while policies being pursued within the UK nuclear sector have increased the momentum towards gender equality (SDG5).

6.1. Skilled Employment

Decarbonising industry through hydrogen could lead to the creation of thousands of jobs, maintain existing jobs and upskill the current industrial work force. The UK Government indicates that the hydrogen economy could be worth over £900 million and provide 9,000 jobs by 2030, up to 100,000 by 2050. This analysis includes the whole value chain of hydrogen, from its production, through distribution to end use. Production of hydrogen utilising nuclear to meet the forecast demands for industry could provide between 18,000 and 59,000 jobs as shown in Table 13.

Table 13- Estimated requirements of reactors and jobs created to meet 25TWh and 105TWh Hydrogen demand from nuclear

Scenario	Hydrogen Demand Estimate (TWh)		Estimated Fleet Requirement		Jobs after scaling	
	Central	Maximum	Central	Maximum	Central	Maximum
Industrial Use	25	105	5 SMRs/AMRs	20 SMRs/AMRs	18,001	59,403

The future requirement for refuelling stations, pipelines, and storage facilities dedicated for hydrogen, brings the opportunity not only creating thousands of new jobs, but could also lead to upskilling the existing workforce and the transfer of skills between industries. Workers involved in carbon-based fuel production, especially oil and gas, have significant knowledge and experience in handling and management of gas on hazardous sites. These transferable skills will be highly beneficial for hydrogen production from nuclear. Furthermore, the use of hydrogen at an industrial site will require training of current workers, providing more skills and greater future employment opportunities.

Additionally, accelerating hydrogen industrial uptake and its distribution by truck as a flexible and scalable method of transportation could also impact job creation. A 100MW electrolyser's output transported via truck could support 200 to 300 additional haulier jobs. Industry needs to start mapping out and understanding their future needs and skills required. The right tools such as certifications, health and safety procedures need to be introduced and provided to build the talent pool. Skilled jobs in the minerals sector demand average salaries of c.£71,000 p.a[1], 20% above the national average for industrial work.

In its 2020 paper, the Nuclear Skills Strategy Group (NSSG) began to look at the skills required to deliver the range and scale of nuclear based energy vectors, noting that from the assumption of 6GWscale reactors anticipated in 2018, this has become considerably larger. The six themes that it believes will deliver the skills required to meet this need include the opportunity for 'transferability' - with sites for nuclear new build spread across the country, there is potential for the replacement of jobs within existing energy sectors with new nuclear and hydrogen employment. There is an opportunity to mitigate the move away from jobs in carbon-based fuel production with new green jobs, in the process levelling up regions across the UK with high-value jobs. Essential is the need to 'excite the next generation' and particularly in that to diversify the workforce.

6.2. Gross Value Added (GVA) to UK Economy

To reach a global net zero target, it is crucial to decarbonise energy intensive industries that greatly contribute to greenhouse gas emissions. These include steel, cement, petrochemicals, mining, asphalt, and others. Global growth of population and urbanisation are set to drive demand for construction materials and the foundation industries have already started acting towards a net zero future. The cement and asphalt industries are fundamental to total GVA in the UK economy. Estimates in 2013 indicate that the cement industry alone contributed £329m in GVA and was part of a total minerals and extraction industry GVA of c.£30bn, that formed the foundation of the UKs 2013 £1.5tn economy.

The Mineral Product Association (MPA) indicates that import levels of cement have been increasing over recent years, and now UK manufacturers are not satisfying all national demand. One of the main reasons is that customers are looking into construction materials with low carbon footprints that are currently not available on the market in large quantities. Currently, more than 20% of the UK cement demand is being fulfilled by imports, this trend can negatively impact employment in the industry. However, switching from fossil fuels to low-carbon hydrogen could support reversing this trend and even increase export market for cement. Decarbonising quickly may ensure these markets are not lost to competing businesses internationally, however this must be done in a way that does not negatively impact 'business-as-usual' operations, nor at a cost that reduces the competitiveness of UK Public Limited Company (plc) products. Lowering emissions from manufacturers will also contribute to higher living standards as local air quality will improve – hydrogen, when burned, produces only water vapour as a product, unlike fossil fuels which emit harmful pollutants (Carbon Monoxide, Sulphur Dioxide, Nitrous Oxides), which contribute to air pollution and have negative impacts on human health.

(the Minerals industry)…… contributed £16bn in turnover to the UK economy in 2018, with over 2,000 active sites and plants, and supported an additional 3.5 million jobs throughout the supply chain. The UK Mineral Products industry is highly productive: each worker produced about £71,000 in 2018, 20% higher than the national average.[2]

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[1] https://www.mineralproducts.org/MPA/media/root/Publications/2022/MPA_SD_Report_2022.pdf

[2] https://www.mineralproducts.org/MPA/media/root/Publications/2022/MPA_SD_Report_2022.pdf

7. Enabling Fuel Switching

This project would demonstrate to the asphalt industry the technical reality and economic possibility of utilising hydrogen. Furthermore, it would add to the growing body of evidence in the use of hydrogen within the cement industry. These two demonstrations would accelerate the use of hydrogen across hundreds of dispersed sites and ensure that UK industry is paving the way towards industrial decarbonisation.

A key aspect of the demonstration is to showcase high-pressure, high-volume trucking solutions for delivering hydrogen to dispersed sites that are currently and will likely remain off the existing natural gas and future hydrogen grid. Many of these smaller dispersed sites would prefer to purchase hydrogen fuel (if it is the best low-carbon option) rather than build electrolysis systems at site, given the flexibility it offers and the reduced risk of supply. Developing this key distribution business is fundamental to the success of hydrogen use within dispersed sites. The trucking solution presented, carrying 1200kg per delivery, marries well with the potential use of H_2 at an asphalt site. A hub and spoke delivery model is a real opportunity to accelerate industry to decarbonise and cultivate a growing distribution business.

Figure 24 - Hub and Spoke delivery model

All heavy industry requires a significant portion of energy. Melting, sintering, drying and heating large furnaces all consume substantial amounts of heat. Industrial heat is a challenge in a variety of industries: chemical, iron and steel, aluminium, paper, glass, brick or ceramics as each manufacturing process is energy intensive and requires high temperatures. Currently, heat is generated by burning coal, oil and natural gas, which contribute to CO_2 emissions. Some of these emissions can be reduced by redesigning the energy intensive, and high-temperature processes to integrate the use of hydrogen. While for some processes electrification might be the most optimal solution, for others there is still requirement for heating furnaces where hydrogen can play an important role.

The use of hydrogen as a fuel in direct heating might be achievable in most of processes driven by direct and indirect heating. Since glass, ceramics and brick have multiple similarities to cement production, these sectors are briefly reviewed in Annex 2.

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Annex 1 – Future Development in Nuclear Hydrogen

NNL Chapter on 'Future Nuclear Backed Hydrogen' part of the 'Bay Hydrogen Hub Hydrogen4Hanson' project

NNL/B10490/06/10/01

ISSUE 3

NNL Chapter on 'Future Nuclear Backed Hydrogen' part of the 'Bay Hydrogen Hub Hydrogen4Hanson' project

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ISSUE 3

Robert Alford; Phil Rogers; Chris Rowe; Emin Veron, 17 March 2023

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Executive Summary

This report provides the output of work package 5 ‘Future Nuclear Backed Hydrogen’ of the ‘Bay Hydrogen Hub – Hydrogen4Hanson’ project, funded as part of the Department for Energy Security and Net Zero (DESNZ) [previously Department for Business Energy and Industrial Strategy (BEIS)] Industrial Hydrogen Accelerator Programme. The overall aim of the ‘Bay Hydrogen Hub - Hydrogen4Hanson’ project is to demonstrate the decarbonisation of energy intensive cement and asphalt production with hydrogen produced using nuclear derived heat and electricity and Solid Oxide Electrolysis Cell technology (SOEC).

Work package 5 looks at the future development and deployment of nuclear technologies beyond the proposed Hydrogen4Hanson demonstration project, including; the economics around the development of future commercial plant, the scalability and replicability of hydrogen production and siting considerations.

Within the report the key findings and recommendations include:

Technology and System Development

Development of nuclear reactor technology over the coming decade could result in a different market for nuclear technologies established through optimised modularisation, a mature and resilient supply chain and innovation in regulatory assessment approaches that drive investor confidence and improved economics. This may in turn unlock thermochemical hydrogen production methods and new markets for nuclear power including hydrogen to support industrial decarbonisation and synthetic fuel production, facilitating decarbonisation pathways for hard to decarbonise sectors such as long-haul aviation. There could also be opportunity for direct coupling of the heat from Advanced Modular Reactors (AMRs) to industrial applications such as cement kilns.

Thermochemical hydrogen production processes could be longer term options that should remain under review and be considered for large scale hydrogen production alongside AMR developments. In the meantime, innovation in the use of steam electrolysis with nuclear energy presents a nearer term option.

When considering future siting, hydrogen production facilities located outside the nuclear licensed site have the potential to reduce cost and improve maintainability compared to systems located on the licensed site. Reflecting on the nuclear industry’s experience working alongside hazardous industry such as chemical production facilities and a ‘ghost ship’ yard at Hartlepool, it is understood the processes and procedures already implemented would be sufficient for hydrogen generation adjacent to Hanson and other industrial sites. The main areas for consideration being hydrogen storage and safety culture changes.

Replicability and Scalability

As presented in this report, the timelines for nuclear developments and the anticipated ramp up of hydrogen demand in the 2030s aligns well, as shown in Figure 1.

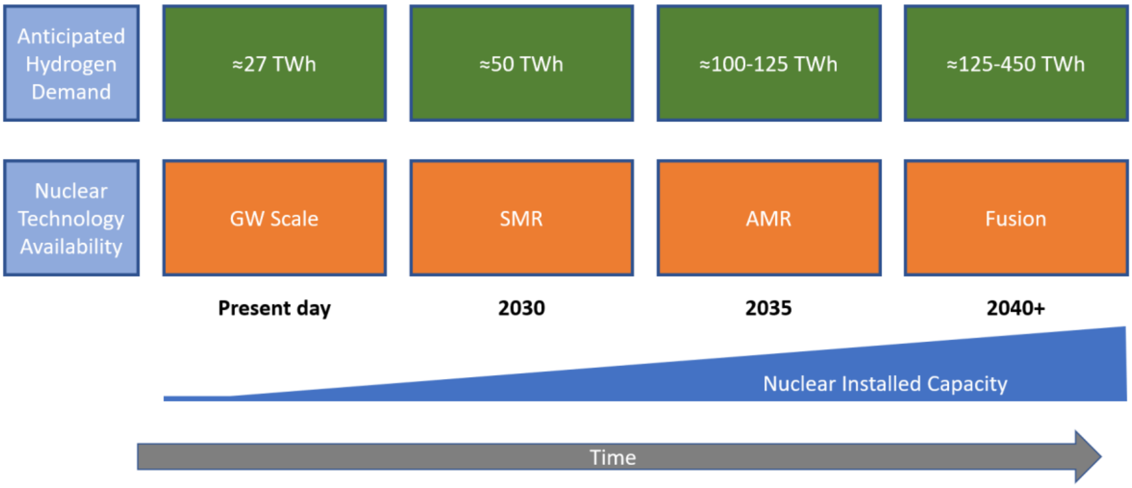

Figure 1- Hydrogen Demand and Nuclear Technology Timeline

The total energy demand for hydrogen by Hanson is 624 GWh per year which equates to approximately 260 MW_{th} nuclear capacity, approximately a quarter of a Rolls-Royce Small Modular Reactor (SMR) or 26 of the U-Battery AMR systems which, as shown within this report, could potentially be sited across the UK near to Hanson sites. When considering siting, as evidenced within this report there is potential nuclear capacity of 83 GW within the UK which shows siting does not need to be a constraint to capacity.

While in the longer term the potential for co-location, especially with AMRs, exists, in the short term it is likely that the supply of hydrogen will be reliant on hydrogen transport and distribution networks. The distribution of hydrogen through the national gas network in the UK, the majority of which is already compatible with hydrogen, could offer a significant opportunity subject to economic and location considerations. This would require development of hydrogen storage, due to the larger volumes of hydrogen required compared to natural gas. There is significant experience and innovation in hydrogen storage with the UK operating the world's oldest salt cavern hydrogen storage facility in Teesside which opened in 1972. Salt cavern storage potential does not present a limiting constraint for the development of a low-carbon hydrogen network in the UK. It is the most developed form of hydrogen storage with potential for UK salt cavern hydrogen storage capacity of 2,150 TWh.

Future Hydrogen Economics

The developing technologies of SMRs and AMRs offer the potential for decreases in the Levelised Cost of Hydrogen (LCOH). The high-capacity factor (percentage of time operating) of nuclear reactors also enables a smaller capacity of hydrogen production technology to produce the same quantity of hydrogen as intermittent renewable technologies. A further decrease in LCOH could be unlocked by adopting novel financing models which are already used on other large UK infrastructure projects.

It is estimated for the LCOH using SOEC technology coupled with a 300 MW_e SMR built under the Regulated Asset Base (RAB) model (with an assumed 6% Discount Rate) hydrogen could be produced at the point of production at a levelised cost of £2.62/kg by 2035 which could be cost competitive with other solutions, supporting the case that nuclear is an economically viable option for hydrogen production in the UK. The use of heat alongside electricity from the nuclear reactor to improve the performance of the SOEC reduces the LCOH at the point of production to £2.56/kg. There is also the potential for the oxygen by-product to provide an additional economic opportunity.

Recommendations

- Use the learning from the Hydrogen4Hanson project to deliver a stronger evidence base for the role of nuclear enabled hydrogen in a future energy system.
- Further invest in development and demonstration of new nuclear reactor technologies (SMR, AMR, Fusion), hydrogen production methods (steam electrolysis and thermochemical) and coupling technologies to enable nuclear enabled hydrogen production to become a proven viable production technique.
- Continue to collaborate across industries and sectors to understand how hydrogen will be transported and stored in a future energy system.
- Refine understanding on co-location considerations for both nuclear plant and hydrogen generation and also hydrogen storage and end use.
- Further consider the oxygen produced as a by-product of hydrogen production including the economic value of capturing and utilising within industry.
- Investigate the feasibility of Hanson connecting more of its sites to the gas network and the use for hydrogen supply.
- Refine understanding of the cost and performance (including the lifetime) of steam electrolysis cells and coupling of technology to nuclear reactors with 50+ year operation.
- Gain an understanding on how demand of cement and asphalt varies throughout the year and geographically and how this may impact the hydrogen production and storage requirements.

Acronyms

Acronym	Meaning
AELP	Accelerated Experience and Learning Programme
AEM	Anion Exchange Membrane
AGR	Advanced Gas-Cooled Reactor
AMR	Advanced Modular Reactor
ASR	Area Specific Resistance
ANSIC	Advanced Nuclear Skills and Innovation Campus
BEIS	Department for Business, Energy and Industrial Strategy
BESS	British Energy Security Strategy
BWR	Boiling Water Reactor
CGO	Ceria Gadolinium Oxide
CAPEX	Capital Expenditure
COMAH	Control of Major Accident Hazards
DESNZ	Department for Energy Security and Net Zero
DOE	Department of Energy (United States)
DSEAR	Dangerous Substances and Explosive Atmospheres Regulations
ECITB	Engineering Construction Industry Training Board
ECM	Electrolysis Cell Module
ESC	Energy Systems Catapult
ETI	Energy Technologies Institute
GDNs	Gas Distribution Networks
GW reactor	Gigawatt scale reactors
HAZID	Hazard Identification
HES	Heat Extraction System
HFCA	Hydrogen and Fuel Cell Association
HHV	Higher Heating Value
HTGR	High Temperature Gas Reactor
HTTR	High Temperature Test Reactor
IP	Intellectual Property

JAEA	Japan Atomic Energy Agency
LCA	Life Cycle Assessment
LCOE	Levelised Cost of Electricity
LCOH	Levelised Cost of Hydrogen
LCOHt	Levelised Cost of Heat
LHV	Lower Heating Value
LWR	Light Water Reactor
NOAK	Nth of a Kind
NPS	National Policy Statement
NSSG	Nuclear Skills Strategy Group
OECD	Organisation for Economic Co-operation and Development
ONR	Office for Nuclear Regulation
OPEX	Operational Expenditure
PEM	Polymer Electrolyte Membrane
PWR	Pressurised Water Reactor
RAB	Regulated Asset Base
RD&D	Research, Development and Demonstration
RR-SMR	Rolls-Royce - Small Modular Reactor
SDGs	Sustainable Development Goals
SEF	Steam Electrolysis Facility
SMR	Small Modular Reactor
SOE	Solid Oxide Electrolysis
SOEC	Solid Oxide Electrolysis Cell
SQEP	Suitably, Qualified and Experienced Personnel
STEP	Spherical Tokamak for Energy Production *(Fusion Reactor)*
SOFC	Solid Oxide Fuel Cell
TCO	Total Cost of Ownership
TRL	Technology Readiness Level
UKAEA	United Kingdom Atomic Energy Authority
VHTR	Very High Temperature Reactors
WP	Work Package

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1. Introduction and Background

This report provides the output of work package 5 'Future Nuclear Backed Hydrogen' of the 'Bay Hydrogen Hub – Hydrogen4Hanson' project, funded as part of the DESNZ Industrial Hydrogen Accelerator Programme[1]. The overall aim of the 'Bay Hydrogen Hub - Hydrogen4Hanson' project is to demonstrate the decarbonisation of energy intensive cement and asphalt production with hydrogen produced using nuclear derived heat and electricity and Solid Oxide Electrolysis Cells technology (SOEC).

The Hydrogen4Hanson' feasibility study is led by EDF R&D and comprises of EDF Energy (operator of Heysham nuclear station), EDF R&D (research arm of EDF), Ceres (electrolyser developer), NPROXX (hydrogen transport technology provider) Hanson (asphalt and cement producer) and National Nuclear Laboratory (NNL) (focusing on future nuclear enabled hydrogen development).

Delivery of the project is as shown in Figure 2 utilising the expertise of consortium members in the life cycle of production, transportation, end use and future developments of low carbon hydrogen.

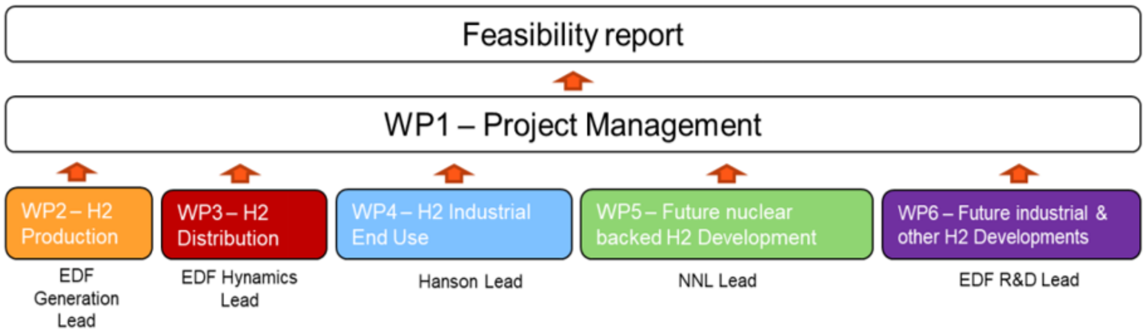


Figure 2- Work package breakdown within feasibility study

Work package 5 looks at the future development and deployment of nuclear technologies beyond the demonstration including; the economics around the development of future commercial plant, the scalability and replicability of hydrogen production and siting considerations. This report has been primarily authored by NNL with input from the wider consortium with substantial input from Ceres on the development of their SOEC technology.

The report includes:

- Applicability of the demonstration to deployment scenarios and future technology options.
- Future nuclear reactor technologies.
- Future Hydrogen production technologies.
- Economic considerations.

The area of social value and wider impact and benefits, which also forms part of WP5 scope, is presented as part of the report "WP5 & WP6 – Social Value"[2].

2. Scope and Objectives

This work package of the overall feasibility study is split into four main areas with sub sections as shown in Figure 3. This structure is followed within the report.

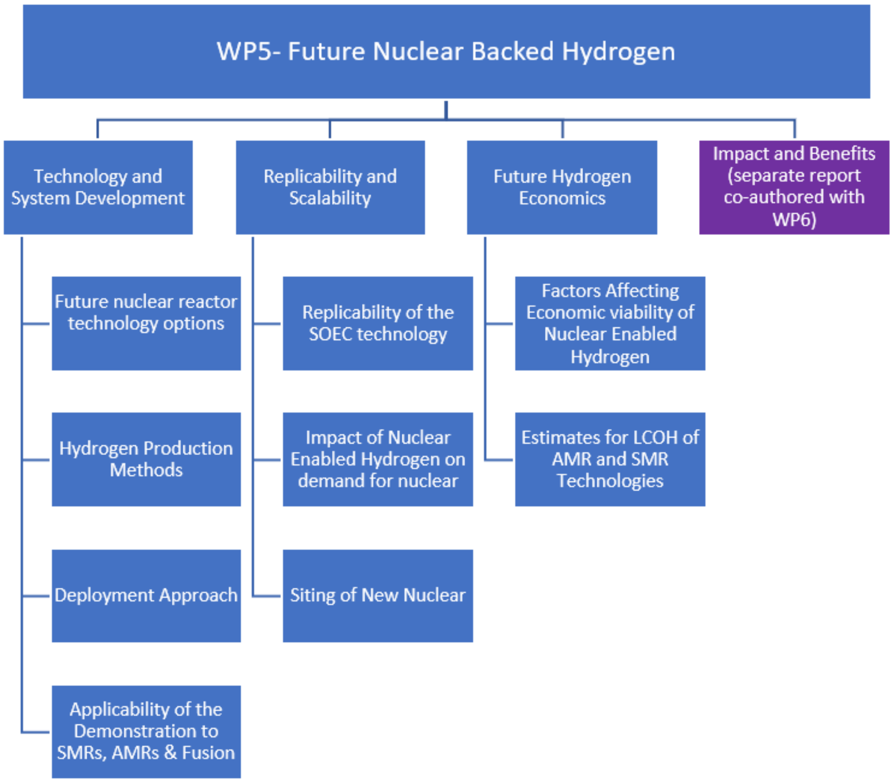


Figure 3- Scope breakdown of WP5

The objectives of this work package are:

- Outline the applicability of the demonstration to future technology and deployment options.
- Obtain a clearer understanding of the future development, deployment and impact of embracing this solution across the mineral processing industry including scalability and replicability.
- Develop wider stakeholder knowledge, confidence and awareness of nuclear enabled hydrogen solutions in industry.
- Support in proving the feasibility of the concept including providing evidence towards the cost effectiveness of the technology to support future nuclear hydrogen production.
- Provide evidence to facilitate the development of new commercial relationships and build market awareness of the opportunity unlocked through this work including the carbon emission saving potential post demonstrator, as captured in the separate impacts and benefits report.

3. Technology and System Development

Hydrogen4Hanson aims to demonstrate the production, distribution and end use of hydrogen produced at Heysham Nuclear Power Station for the decarbonisation of Hanson activities in the aggregate sector. This demonstration makes use of existing, deployed UK nuclear assets in the form of the Advanced Gas-Cooled Reactor (AGR) coupled with steam electrolysis from Solid Oxide Electrolysis Cells (SOEC). Such a demonstration would help to build a world-leading evidence base on the generation of hydrogen from nuclear technology that can be applied to the deployment and siting of future non-electric applications of nuclear in the UK.[3] Therefore, with the ongoing development of large scale, small modular and advanced modular reactors in the UK, this project provides a key platform on which to make a real-world demonstration of technologies that can make a valuable contribution to the Net Zero energy transition.

Installing the electrolyser in the vicinity of the reactor avoids electricity grid costs that are borne by systems that are attached to the grid or renewables. The applicability of this demonstration to coupling with other nuclear technologies is relevant in three areas:

- Deployment model and site layout to minimise costs
- Use of direct heat from the reactor steam circuits
- Operating temperature and efficiency

Results from this work package show that there are likely to be small differences in how steam electrolysis is coupled to other reactor technologies, but overall, l the principles being explored in this feasibility will be applicable to all technologies. Efficiency gains from steam electrolysis should apply to all reactor technologies, with some potentially offering greater gains than others. In all cases, the deployment model for the reactor and hydrogen production system needs to be considered together to reduce lifecycle cost of hydrogen.

3.1. Future nuclear reactor technology options

The UK currently has nine operational nuclear reactors with a capacity of 5.8 GW generating ca. 15% of UK electricity across five sites[4], all reactors except Sizewell B are due to close within the next 5 years. In construction is Hinkley Point C, due to come online in 2027[5] and provide 3.2GW of electricity. In November 2022 the UK government announced the investment and approval of Sizewell C[6] that will be of the same design and size (3.2 GW) as Hinkley Point C and is planned to come online in the early-2030s.

The government also announced in the British Energy Security Strategy[7], the plan for up to 24 GW of new nuclear capacity by 2050 providing ca. 25% of UK electricity demand. While this current target only considers electricity production, EDF have proposed the potential for a Sizewell C energy hub[8] that could include the production of hydrogen, direct air capture technology and direct use of heat.

Current UK policy is for support of new nuclear build from a technology agnostic perspective. Figure 4 outlines how this could incrementally progress from current day GW scale light water reactors (i.e. Hinkley Point C), through Small Modular Reactors (SMRs), Advanced Modular Reactors (AMRs) and Fusion power; each technology potentially adding nuclear capacity and unique services to the UK energy system. There is, however, no decision on construction of a fleet of GW, SMR or AMR technologies; apart from the Hinkley Point C and Sizewell C developments. Further decisions may be forthcoming on fleet deployment, which could see multiple SMRs planned for construction over 2030/2040s. The target for operation of AMRs in the UK is demonstration in the early 2030s, with the potential for fleet deployment thereafter.

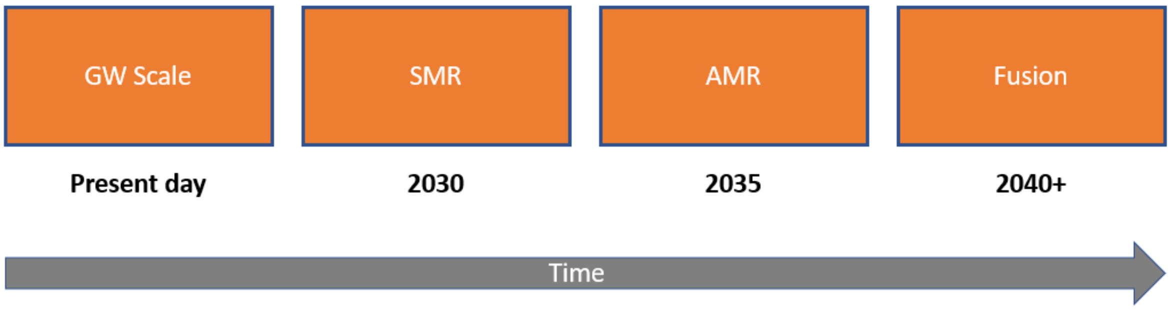


Figure 4- Indication of timeline for commercialisation of nuclear technologies

Industrial applications such as asphalt and cement decarbonisation will also be progressing in tandem with the development and deployment of nuclear technology and so alignment of requirements from the energy end users (for the purpose of this study, Hanson will be used to outline examples) with the deployment scale, location and methodology will be important to maximise value to achieving Net Zero. The power output of a reactor selected for coupling with a hydrogen production technology will depend on a variety of factors including size of the demanding market, the infrastructure near the reactor, investor confidence and public support for the type and size of reactor at a given site.

A key factor to consider is the development of technologies and deployment enabling improvements in the hydrogen production over the coming decades and an alignment of public and private funded development programmes that could ultimately combine as an overall system. This is further supported by a range of research into energy system integration and evolution over the coming decades[9]. Furthermore, the extension of renewable based technologies and how nuclear technologies and related energy outputs will interact in an increasingly complex market needs careful consideration.

3.1.1. Small Modular Reactors

Alongside the GW scale reactor developments at Hinkley Point C and Sizewell C, SMRs and AMRs are being progressed in the UK.

SMRs represent smaller versions of current reactor technology operating with water as their reactor coolant. The UK Government is progressing through the Rolls-Royce SMR (RR-SMR) programme, which is partly publicly funded. This is proposed as a 470 MW_e scale reactor[10] and planned for first operation in the early 2030s. Unlike current nuclear stations the RR-SMRs will be factory built as far as practicable with a philosophy of deploying proven technology with improved economics offered by modularity. The footprint of a RR-SMR is also far smaller than a conventional power station at one-and-a-half UK football pitches[11], which also supports improved economics through lower capital costs with a power to the grid cost of £60-70 per MWh[12].

Other SMR reactor technologies are also seeking to enter the UK market by submitting applications to enter the Generic Design Assessment process [13,14].

As well as electricity generation, there is already significant interest in the opportunities for SMRs for wider energy applications such as hydrogen and synthetic fuel. Paul Stein, Rolls-Royce Chief Technology Officer said in 2021

> *"One of the beauties of the SMR approach, is it becomes quite a low-cost source of energy for other parts of the decarbonisation scene, such as hydrogen and synthetic fuel. One UK-SMR and plant will be able to produce 170 tonnes of hydrogen or 280 tonnes of net-zero synthetic fuel per day."*[15]

This clearly shows the considerations already underway on the use of nuclear energy from SMRs to support beyond electricity applications and this project could become an enabler to prove heat integrated hydrogen deployment with nuclear technology.

KEY FINDING

By the early 2030s the market for nuclear technologies could be quite different from today, with multiple technologies driving cost reductions through optimised modularisation, a mature and resilient supply chain and innovation in regulatory assessment approaches that drive investor confidence and improved economics opening new markets, including hydrogen.

3.1.2. Advanced Modular Reactors

The next generation of nuclear technologies are referred to in the UK as AMRs. These technologies use novel cooling systems or fuels to offer inherent safety features and higher temperature outputs to unlock higher efficiency electricity production and enhanced ability to support non-electric applications such as supply high-grade heat, high temperature hydrogen production, district heating and the efficient production of synthetic fuels.

Although the UK Government is open to the potential for any AMR technology to be developed in the UK (the range of which are shown in Figure 5), it has committed to the early stages of a programme for the demonstration of application of a High Temperature Gas Reactor (HTGR). This was chosen on the basis that HTGRs are considered most likely to make an impact on decarbonisation by 2050, compared to other AMR technologies as part of the BEIS AMR Technical Assessment in July 2021.[16]

System	Neutron Spectrum	Coolant	Outlet Temp (°C)	Fuel Cycle	Technology Readiness Level[2]
HTGR / VHTR High / Very High Temperature Gas Reactors	Thermal	Helium	700 – 950 900 – 1000+	Open	7 / 5
SFR Sodium-Cooled Fast Reactors	Fast	Sodium	500 – 550	Closed	7
SCWR Supercritical Water-Cooled Reactors	Thermal / Fast	Water	510 – 625	Open / Closed	2
GFR Gas-cooled Fast Reactors	Fast	Helium	850	Closed	2
LFR Lead-cooled Fast Reactors	Fast	Lead	480 – 570	Closed	4
MSR Molten Salt Reactors	Thermal / Fast	Fluoride Salts	700 – 800	Closed	4 Thermal 3 Fast

Figure 5- Summary of AMR Technologies[16]

There are a number of current commercial reactor propositions being explored as part of the DESNZ AMR Research, Development and Demonstration (RD&D) Programme[17] which aims to have an operational HTGR demonstration in the UK by the early 2030s. The HTGR designs and propositions participating in the programme are:

- Micro Modular Reactor+ (MMR+)[18] from Ultra Safe Nuclear Corporation (USNC) who are developing a HTGR, based on the MMR design in the United States. Each MMR unit is small ca. 15 MW thermal energy (ca. 5 MW electrical) with the plan to be deployed in groups of 1-10 modules and is being promoted as part of the RD&D programme for the ability to produce hydrogen and synthetic fuels.
- A Japan Atomic Energy Agency (JAEA) based technology, centred on the High Temperature Test Reactor (HTTR), which is currently operational in Japan and has demonstrated operation at 950°C[19]. The current study into this technology is led by NNL.
- U-Battery are determining the optimum size, type, cost, and delivery method for their conceptual design ca. 10 MW thermal reactor, with the aim to provide a source of low carbon, locally embedded process heat and power that can displace the use of fossil fuels.
- EDF are focusing on end-user requirements to determine the reactor design characteristics most suitable for a HTGR demonstration. EDF proposes the Hartlepool

Heat Hub as a host site for the UK's first HTGR demonstration, but at this stage have not committed to a reactor design.

These organisations are currently completing Phase A: Pre-FEED of the three phase AMR RD&D programme[17] with Phases B and C being subject to further funding allocations and competitive processes.

HTGRs are targeted primarily to the generation of electricity and/or high temperature heat. These outputs can then be used to produce hydrogen using thermochemical, electrochemical or hybrid processes. HTGR systems can supply nuclear heat and electricity over a range of core outlet temperatures between 700 and 950°C, or more than 1000°C as a future target for Very High Temperature Reactors (VHTR)[i]. The reactor configuration could be either a "prismatic block" (visually similar to an AGR graphite core) or a "pebble-bed" core. Although the shape of the fuel element for the two configurations are different, the technical basis for both configurations are similar, such as the coated particle fuel in a graphite or ceramic matrix, graphite moderation, helium coolant, and relatively low power density.

Following this decision in early 2022 BEIS announced it was providing up to £2.5 million in innovation funding to support the development and demonstration of HTGR technology in the UK known as the AMR 'RD&D: Phase A'[20]

KEY FINDING

HTGR / VHTR systems have the potential to support several hydrogen production methods from steam electrolysis to thermochemical methods, support industrial decarbonisation and synthetic fuel production.

As shown in Figure 6 and discussed above, the heat produced by an AMR can be used for a broad range of applications either directly as heat or through conversion into other energy vectors. Through a single nuclear plant an industrial hub could be "powered" producing the electrical, heat and hydrogen production demands for a breadth of industrial applications. Whilst using heat from other nuclear technologies is possible, the higher grade heat from AMRs is uniquely placed to unlock the full range of potential applications.

KEY FINDING

Industrial processes based on high temperatures that require modest outlet temperatures (700-850°C) have great potential for application of HTGRs in the next decade and thus there may be opportunity for direct coupling of the heat from a HTGR to industrial applications such as cement kilns with hydrogen top up to achieve the ca. 1300°C required.

[i] Note that only VHTRs operating at over 1000°C are classed as GenIV, as categorised by the Generation IV International Forum. While HTGRs are similar technologies, they are not GenIV.

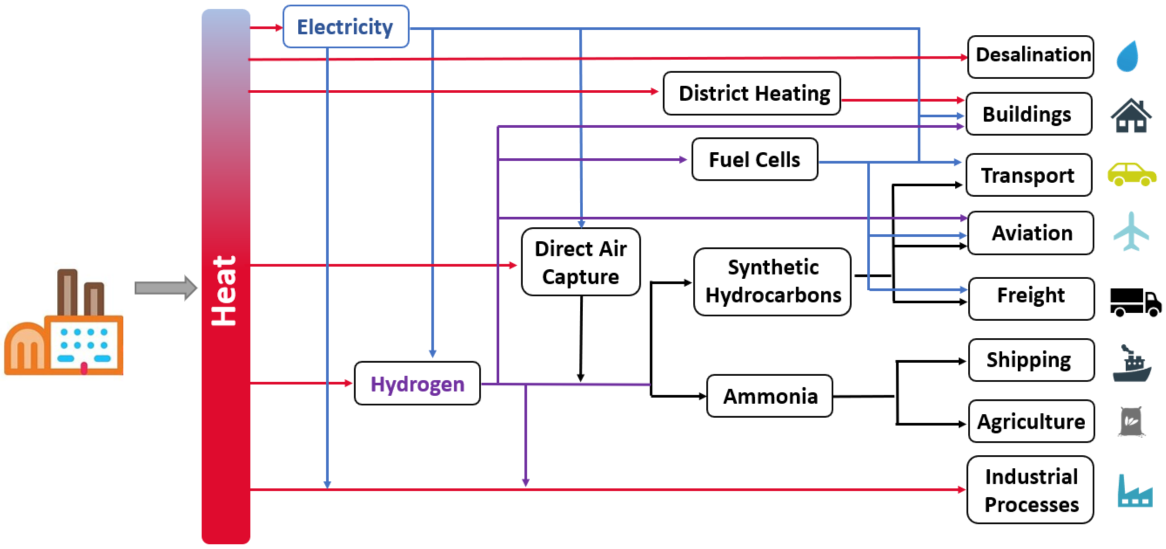


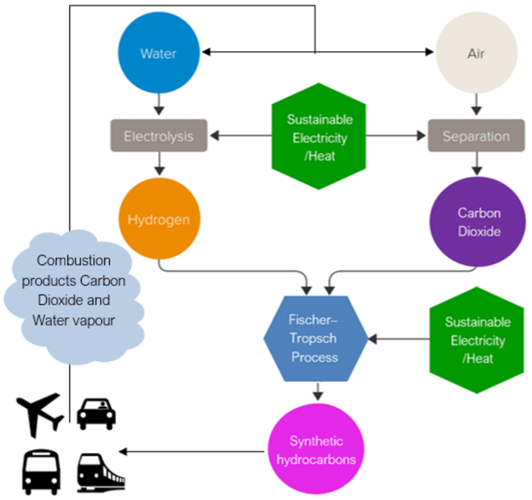
Figure 6- Nuclear opportunities to support net zero

Focusing on hydrogen specifically, as well as potentially being used directly as a fuel for industrial processes, building heating and transportation, hydrogen also offers a feed stock for production of high energy dense fuels for applications where continual supply of large quantities of energy is not possible such as long-haul aviation and shipping. In these applications, synthetic liquid fuels, such as ammonia or synthetic hydrocarbon fuels offer a solution. Synthetic hydrocarbon fuels have similar benefits to current fuels and can be used as 'drop in' carbon neutral fuels to current transport systems and distribution infrastructure without any modifications.

Production of these fuels is highly energy intensive in both the feedstock production, (hydrogen, carbon dioxide and nitrogen), and in the production processes themselves. Nuclear is well placed to provide the energy inputs in the form of electricity and heat to both aspects of the production process.

This demonstration project is relevant to low carbon fuels production as it shows the ability to remove heat from a nuclear system for the purposes of an industrial process; in this case hydrogen production, and in the ability to produce hydrogen utilising both electricity and heat from the reactor.

Figure 7 and Figure 8 show the processes for production of synthetic hydrogen carbon fuels and ammonia respectively with the electricity and heat inputs indicated with green hexagons. This feasibility study can show the ability of nuclear to fulfil the energy inputs offered by these processes.



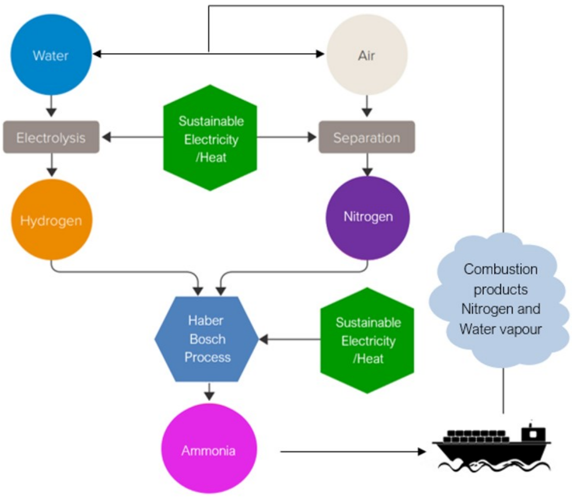


Figure 7- Synthetic Hydrocarbon fuel production path

Figure 8- Ammonia fuel production path

In the 2019 Digest of UK Energy Statistics[21] data shows that the UK consumed the equivalent of 455 TWh of petrol and diesel for road transport and 159 TWh of aviation fuel. For comparison, the total UK electrical generation in 2019 was 323 TWh[22].

The demonstration of the wider industrial applications, such as synthetic fuel manufacture, supports the development of nuclear technology, specifically AMRs in terms of building investor confidence and proving opportunities for co-location.

KEY FINDING

The option to deploy nuclear at scale for both domestic hydrogen production, and energy input as a feedstock for synthetic fuel production processes, could raise the ceiling and open decarbonisation pathways currently believed to be out of reach for hard to decarbonise sectors such as long-haul aviation.

3.1.3. Fusion technology

In the longer term, (demonstration from 2040+) it is anticipated nuclear fusion power will reach commercialisation as an option which provides electricity and direct heat as a source for producing hydrogen. The heat produced from a commercial fusion reactor could exceed 600°C providing similar high temperature benefits of AMRs with some potential benefits in terms of inherent safety, alternative regulatory approaches and reduced lifetime of hazardous waste products. The UK is a world leader in fusion technology and United Kingdom Atomic Energy Authority (UKAEA) are developing the Spherical Tokamak for Energy Production (STEP). In October 2022 it was announced that West Burton, North Nottinghamshire was selected as the home of the STEP fusion energy plant[23].

3.2. Hydrogen Production Methods

Alkaline and Polymer Electrolyte Membrane (PEM) electrolysis are conventional water-splitting hydrogen production technologies, which operate at ambient temperatures and up to approximately 80°C. However, steam electrolysis from Solid Oxide Electrolysis Cells (SOEC) is the focus of this study due to improved performance at the higher temperatures (up to 630°C) that can be provided by nuclear. This could unlock greater gains in efficiency at the temperatures offered by GW scale, SMR and AMR technologies.

The areas of focus for gains in efficiency of hydrogen production will come from a reduction of degradation of the electrolysers during use, from delamination and poisoning, which allows for better throughput over time. This can be combined with efficiency improvements from nuclear heat generation to generate more units of hydrogen, for the same units of energy input.

Further efficiency gains could be achieved by thermochemical hydrogen production, which is an early technology readiness technology but could mature in the longer term. Due to the high temperatures required, these technologies can only practically be coupled to higher temperature AMR technology.

This section will explore steam electrolysis and thermochemical technologies in turn.

3.2.1. Steam Electrolysis – Solid Oxide Electrolysis Cells (SOEC)

Steam electrolysis is characterised by the potential to achieve higher efficiency than conventional PEM or alkaline electrolysers. A significant contributing factor is due to the water feedstock being provided to the electrolyser as steam, which means that the latent heat of vaporisation is already overcome and the amount of electrical energy required to split water (H_2O) to hydrogen and oxygen is reduced.

In theory the higher the steam temperature the greater overall efficiency, but the latent heat of vaporisation is very significant, so major efficiency gains are made simply by providing water as steam, rather than liquid (i.e. temperatures above 100°C). At the even higher temperatures there would be additional marginal and potentially disproportionately small efficiency gains.

Globally Steam Electrolysis for hydrogen production is at early stages of commercial availability, with a number of organisations offering technology solutions. Of these, the Ceres technology has some unique features.

The Ceres low temperature SOEC technology, as shown in Figure 9, based on a steel-supported Solid Oxide Fuel Cell (SOFC / SO Electrolyser Cell) based on a CGO (Ceria Gadolinium Oxide) electrolyte that operates at 530 to 630°C. Ceres has a proprietary process to deposit very thin ceramic layers on micro-perforated steel plates to make its cells. Hundreds of these cells are layered up into SOEC stacks.

These stacks are built up into an array, along with hot balance of plant components (such as heat exchangers and heaters) into an Electrolysis Cell Module (ECM). This modular approach allows each module to be constructed and tested prior to installation at the site. It also allows for a high degree of fault tolerance and redundancy. Furthermore, it also enables a distributed supply chain to be developed for various elements up and down the system structure.

For the initial prototype electrolyser systems, the ECM units are packaged within a 40ft ISO shipping container; the system shown in Figure 9 is a 1 MW-class Solid Oxide Electrolysis system.

Materials selection is a key required improvement for hydrogen production technology. SOECs will need to be able to be supplied at scale with relatively inexpensive materials, or a reliable indigenous recycling route will be required for high performance materials. Ceres SOEC stack technology is easily recyclable with stacks that are >95% stainless steel. Even for low cost systems at present there is a cost curve which could be realised through the development of a more mature supply chain.

KEY FINDING

Ceres SOEC is metal supported technology operating at lower temperatures (530-630°C) than ceramic SOEC (600-900°C) offering improved robustness, more cost-effective system materials and easily recyclable stacks.

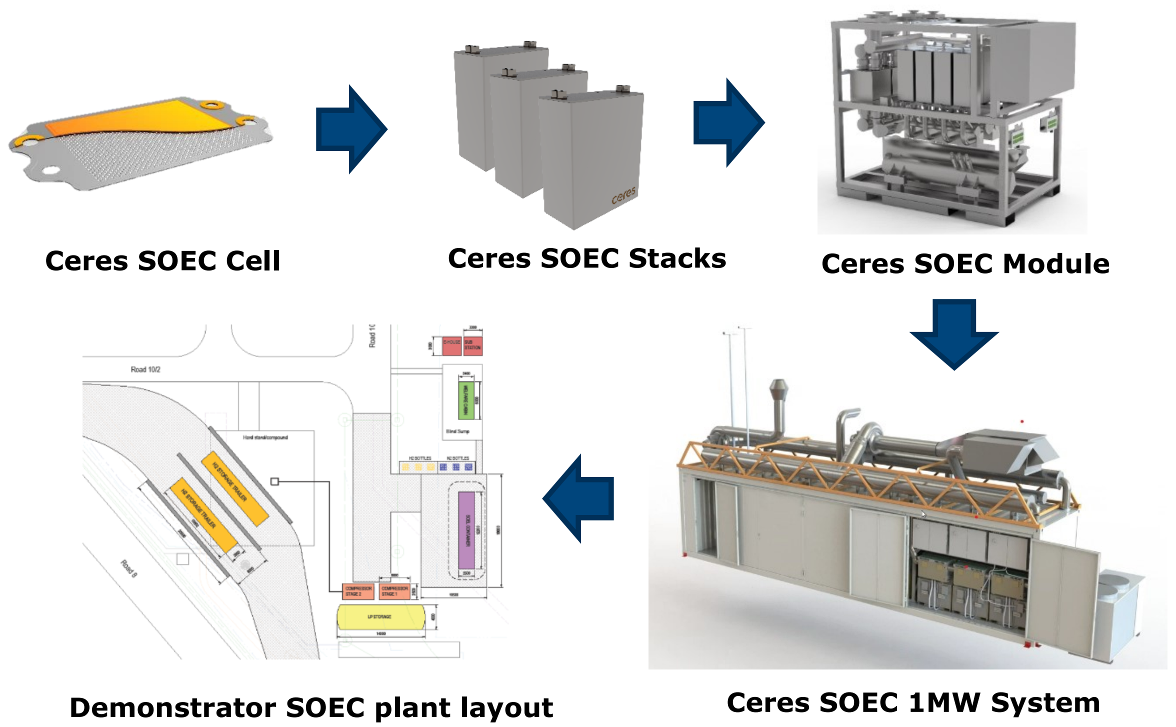


Figure 9 - Pictorial representation of the Ceres SOEC system

3.2.2. Thermochemical hydrogen production

Thermochemical hydrogen production has been the subject of research and development for decades, but the low level of investment and alignment with AMR development programmes results in this technology remaining at low technology readiness levels. The benefit of these technologies is that through a series of controlled chemical reactions at high temperature and in the presence of catalysts, water can be split to produce hydrogen at temperatures that can be achieved by AMRs without a large electricity demand. Chemicals used in the production process are recycled, producing a closed loop that consumes only water and heat. Access to this technology could provide additional supply chain and technology resilience, compared to a hydrogen economy reliant solely on electrolyser and material supply chain.

There are more than 100 potential heat assisted thermochemical production cycles. Some processes also include an element of electrolysis, although the power demand is much lower compared to direct electrolysis of water. Of the potential cycles, two have seen the greatest investment and research: Sulphur-Iodine and Copper-Chlorine. These require temperatures of ~900°C and 630°C respectively.

The Sulphur-Iodine process has seen significant development in Japan, where it is proposed as a large-scale hydrogen production route coupled to HTGRs. Meanwhile, the Copper-Chlorine route has been developed more extensively in Canada where again the process and its temperature requirement aligns with past AMR development programmes.

Thermochemical technologies (while unproven currently at larger scales) if proven, could rely on more mature supply chains than electrolyser technology, so if unlocked the technology could be simpler for the supply chain to support, and will provide growth in a way which does not compete with steam electrolysis. Their deployment would benefit from the experience and demonstration of hydrogen generation alongside nuclear technology, to underpin the evidence base for regulatory review of a closely heat integrated technology.

Investment in thermochemical hydrogen production and demonstration is also an enabler for further building the case for nuclear enabled hydrogen, building confidence in co-location of nuclear plant to chemical facilities and the potential for thermochemical hydrogen production to complement steam electrolysis if scalability of SOEC prove harder than perceived.

KEY FINDING

Thermochemical hydrogen production processes are likely to be longer term options that should remain under review and be considered for large scale hydrogen production alongside AMR developments. In the meantime, innovation in the use of steam electrolysis with nuclear energy presents a nearer term option.

3.2.3. Comparison of hydrogen production technologies

The overall cost of hydrogen production from both these technologies however is still understood to a limited extent and will be the key driver over the uptake of either hydrogen production technology. There will be opportunity-cost to bear in mind for both these technologies and so if thermochemical works out cheaper and the higher temperature reactor technologies are commercialised, they would be likely to displace steam electrolysis for new deployments. Existing deployments however would likely operate in nimbler and changing markets. This depends on how markets mature – if there are electric vehicles, electric heating, insulation, and a phase out of the gas network then the overall demand will be lower and hydrogen will have a more limited role in the clean energy system, focused on heavy transport and industrial applications.

KEY FINDING

Thermochemical technologies could be enabled by the rollout of steam electrolysis providing an alternative production route to achieve future cost reductions of hydrogen production.

3.3. Deployment Approach

Demonstrating the deployment model with hydrogen production in the vicinity of the reactor to avoid electricity grid transmission costs and enable the direct use of heat from the reactor steam circuits ensures that the outcomes from the current feasibility can directly inform decisions on future technologies and deployment, regardless of the reactor technology.

This will be subject to making suitable safety case claims and arguments, and production of the necessary supporting evidence. The evidence required and the nature of the claims may differ between technologies due to fundamental differences in the underlying safety case.

3.3.1. Site Layout

The production of hydrogen using nuclear derived heat (as opposed to conventional electrolysis using just electricity) requires additional equipment to be relatively close to the nuclear reactor. A hypothetical layout of the required coupled equipment including the addition of a Heat Extraction System (HES) and Steam Electrolysis Facility (SEF) is shown in Figure 10. While the HES in the demonstrator is making use of secondary circuit steam by coupling the steam electrolyser to the existing infrastructure and viable extraction points, future plants built specifically for hydrogen production, could be more optimally designed to extract heat at various points and temperatures to balance economics of hydrogen and electricity production.

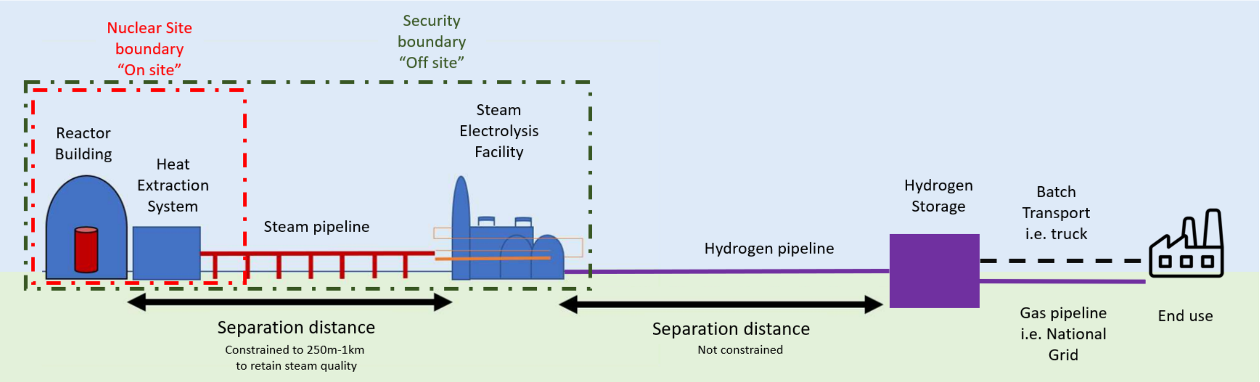


Figure 10- Hypothetical layout of a facility with typical nuclear site plant buildings, including heat extraction system (on site), steam electrolysis facility for hydrogen production (off-site) and transport, storage and end use facilities

This example layout shows the SEF at a location outside the nuclear site licence boundary. This would be expected to offer economic benefits due to more straightforward access for installation and maintenance and has the potential to increase the distance between the reactor and a potential external hazard explosion risk from hydrogen.

NNL has previously carried out an extensive exercise [24,25] to review the potential for hydrogen production at or near a nuclear installation with the following findings:

- Generation of hydrogen from a nuclear energy source is not in itself novel or likely to introduce a disproportionate level of risk to the nuclear site, if managed appropriately. Using the heat energy from the reactor is understood and currently used to drive turbines. In the existing arrangements, safety controls already exist for scenarios where the turbine trips and these approaches would provide protection to nuclear steam being used for other applications.
- Considerations for storage of hazardous chemicals and keeping the nuclear site informed of surrounding facilities in an intelligent way will be very important to nuclear safety. Examples of sites where nuclear reactors already adjoin industrial sites include chemical production facilities and a 'Ghost Ship' Yard at Hartlepool and at Heysham (1 and 2) there is a unique position based on co located nuclear reactors and close to Heysham port.
- If the hydrogen production facilities are located on the licensed site, depending on the plant arrangements, it may require Office for Nuclear Regulation (ONR) approval for any modifications and improvements in the technology. The ONR permissioning process would add a level of approvals and permissioning which would increase timescale for any changes to the hydrogen facilities, when compared to a conventional plant not located on a nuclear licensed site. Chemical plants are typically the subject of more design changes over their plant lifetime than nuclear facilities and hence if located off-site these changes would be easier to administer.
- The SEF, which takes the steam energy for use in the electrolysis processes, is not required to be on the site as this is essentially a chemical processing plant which once being fed with the high temperature steam can be operated independently of the reactor site.

- While a once-through steam cycle could be utilised, i.e. waste heat from hydrogen production vented to atmosphere, this is a significant waste of energy, it is more likely steam would be returned to the licenced site for reheating. This will thus introduce the need for considerations of both discharge 'off-site' to the hydrogen production facility and then returning the steam on to the licensed site for re-heating.
- A chemical processing plant often has a lifetime of less than 10 years, whereas nuclear plant has a lifetime of ca. 60 years and thus the current 10-year periodic safety review for nuclear reactors would not offer the frequency of review required when considering coupled chemical processing technology. The industry has experience in managing this, an example being Hartlepool Power Station which actively builds relationships with its industrial neighbours and inspect their sites as part of their interactions.
- The generation of flammable gases, such as hydrogen, and the use of hazard / toxic materials, e.g. electrolysers, naturally introduces hazards and potential fault scenarios. These types of hazards are well understood in the nuclear industry and although they will result in additional faults and increased risk they can be assessed and appropriately managed in line with the current hazard analysis undertaken for a reactor site.
- The production of oxygen will be a by-product from the production of hydrogen from water. This could pose a significant hazard and if it does then it may require a Dangerous Substances and Explosive Atmospheres Regulations (DSEAR) assessment, due to its oxidising properties increasing the potential for fire, and the consequences of a fire. However, it also offers an economic opportunity and work at Oak Ridge national Laboratory in the US is starting to show that capturing and utilising the oxygen could help to reduce the overall cost of hydrogen. Although it is noted that like the hydrogen, large quantity stocks would need to be transported and stored away from the nuclear site to reduce the associated hazards.

Reflecting on the above observations from NNLs previous work, a sensible consideration for future siting beyond the demonstrator, would be to locate the hydrogen production facilities off the nuclear licensed site, leaving only the heat exchangers for the hydrogen facilities on the licensed site, as shown in Figure 10. The heat exchangers will directly interact with the secondary reactor systems due to their use of the nuclear derived steam. Thereby, leaving the on-site fault studies to consider the new plant related faults in the hydrogen facility heat exchanger (and its feedlines) where their failure could impact the reactor and/or its safety related equipment. The potential hazards arising from the hydrogen production would be an off-site consideration as part of the nuclear safety case external hazard assessment.

Such a deployment approach for future site layouts is dependent on the evidence base that can be built from the Hydrogen4Hanson project, whereby deployment of hydrogen generation at a small scale on the nuclear licensed site would help provide a stepping stone to offsite heat integrated deployment.

KEY FINDING

Site layouts that include the hydrogen production facilities off the nuclear licensed sites could reduce cost and improve maintainability compared to systems located on the licensed site.

3.3.2. Co-location with Demander

The consideration of co-locating the production and storage with end use for asphalt/cement manufacture is explored in the WP3 report where a Hazard Identification (HAZID) workshop was undertaken by Hanson. The main finding of this workshop was as many sites are already storing chemicals that fall under the Control of Major Accident Hazards (COMAH) regulations, the multiplier calculations for combined storage with hydrogen could push the sites into lower tier COMAH, representing a higher site hazard compared to the current categorisation. Therefore, if it was decided to have significant quantities of stored hydrogen at Hanson sites this could cause additional control measures for lower tier COMAH which are not yet in place, as natural gas storage on sites is minimal. Another consideration is if co-location could lead to ‘on demand production’ with hydrogen only produced when needed, if this was the case Hanson have concluded it would almost have no impact on current site procedures as the site will fall very short of the COMAH lower tier regulations. The main observation identified in the HAZID as discussed in WP3 report is the culture change required for managing industrial quantities of hydrogen. Regardless of COMAH, the safety culture within Hanson sites would need to transition.

KEY FINDING

When considering co-locating the production and storage with end use, in this case asphalt/cement manufacture, reflecting on the nuclear industry’s experience working alongside hazardous industry such as at Hartlepool, it is understood the processes and procedures already implemented would be sufficient for hydrogen generation adjacent to Hanson and other industrial sites with the main areas for consideration being hydrogen storage and safety culture changes.

3.4. Applicability of the Demonstration to SMRs, AMRs and Fusion

The proposed demonstrator could provide steam to the electrolyser at 180°C, which could improve electrolyser efficiencies significantly. This compares to the potential output temperatures of nuclear technologies: Light Water Reactors (SMRs and GW scale stations) provide circa 300°C; HTGRs could operate at up to 950°C in the longer term; with other Generation IV nuclear technologies, for example molten salt reactors and sodium-cooled fast reactors potentially operating at higher temperatures in the range 500-800°C.[16]

All these technologies can provide steam and therefore the demonstration remains relevant to future and alternative reactor technology options. The provision of heat from the reactor steam circuits to electrolysers can provide efficiency gains, and this would be true for any system (regardless of the nuclear technology) that includes the generation of steam. The steam could typically be taken from a point in the steam turbine where it minimises the loss of electricity generation and therefore the current demonstration is highly applicable to any reactor technology and associated systems where steam is involved. While the temperatures will be different, the principles are the same.

Some future reactor systems may apply gas turbine technology for electricity production and may therefore not include steam systems. In this case an alternative heat transfer system would be required, or inclusion of a steam generator specifically for the purposes of feeding steam to the electrolysers.

Differences may also occur between nuclear reactor systems where the operator maintains fine control of core reactivity through controlling the steam system balances.

4. Replicability and Scalability

While the demonstration as part of this project is key in enabling the understanding of nuclear derived hydrogen production, to embrace the full potential offered by nuclear power coupled with SOEC technology requires an understanding of replicability and scalability. This section initially looks at the replicability of the SOEC technology to meet the demand and scalability of the overall nuclear enabled hydrogen solution to deliver the required scale alongside the potential demand for hydrogen in the aggregate sector.

The remainder of this section focuses on the impact of nuclear enabled hydrogen on demand and nuclear siting opportunities, including cross-comparing the expected increase in hydrogen demand with technology and deployment opportunities for nuclear, showing that the timelines could align well. In particular nuclear enabled hydrogen production capacity could be available to meet a demand increase in the late 2030s. This is followed by a review of nuclear siting and hydrogen storage and transport including salt caverns hydrogen storage.

4.1. Replicability of the SOEC technology

Ceres' technology is evolving with future generation cells developed specifically for electrolysis. Stack performance improvements will increase the hydrogen production output from a combination of increasing the cell size and operating current and adding more cells per stack as shown in Figure 11. Further performance gains will come from increasing the steam utilisation up to around 80% and, with small mechanical design changes, the operating pressure to 1 bar. These performance improvements will allow the module size to be reduced for a power requirement of 1 – 5 MW, depending on the integration. The sizing of the module allows on-road transportation for access to plant and servicing requirements.

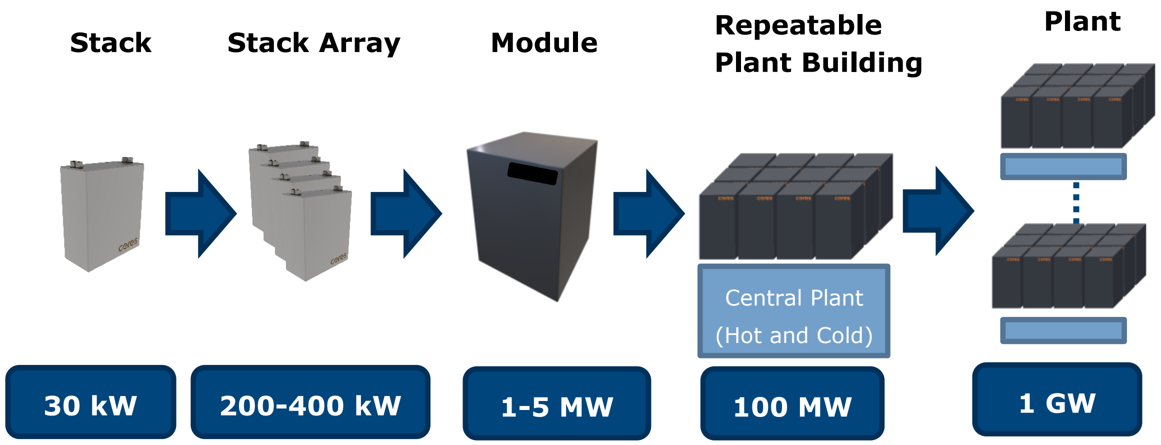


Figure 11- Single stack to large array increase in SOEC technology scale

The modular systems can be built into 100 MW class repeatable plant buildings. One of the clear advantages of SOEC systems is the ability to thermally integrate with industrial processes such as asphalt, cement, steel, ammonia and synthetic carbon fuel production. Integration with the low and high grade steam feeds available at nuclear plants may enable system efficiencies of greater than 90% to be achieved as shown in Figure 12.

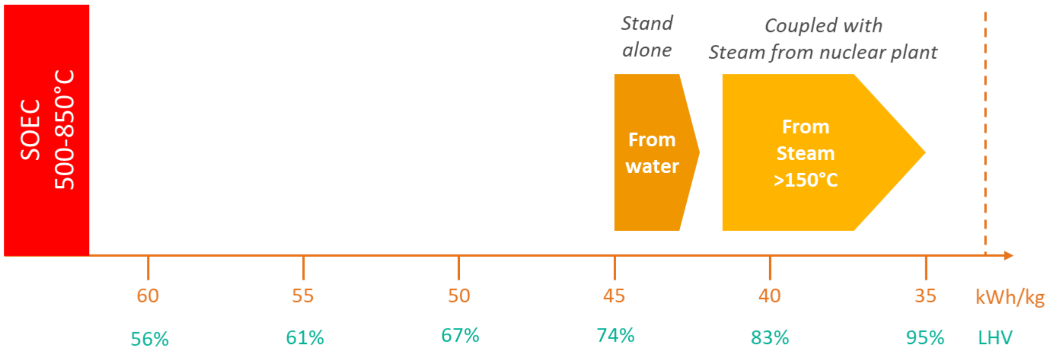


Figure 12- Efficiency of the SOEC system without and with external heat input based on Lower Heating Value (LHV)

KEY FINDING

By using steam directly from the nuclear plant, Ceres SOEC can produce hydrogen at high efficiency (>90% LHV), requiring ~37kWh electrical power per kg hydrogen produced.

4.1.1. Route to SOEC Commercialisation

Ceres are a UK technology licensing company of SOFC and electrolyser technology, establishing commercial partnerships with companies such as Bosch and Doosan to scale up volume manufacture of the stack technology.

The SOEC technology is now extremely well placed for a UK manufacturing partner to scale up volume manufacturing of Ceres technology in the UK, with significant levelling up and job opportunities. As an Intellectual Property (IP) company, Ceres own all the end-to-end IP of the SOEC technology allowing full scale up in the UK.

Ceres' electrolyser technology is based on the proven SOFC technology, with the current demonstrators using identical cells and stacks for both fuel cell and electrolyser systems. The first 1 MW class SOEC demonstrator built with these stacks will start a 3-year test programme from 2023 (Figure 13).

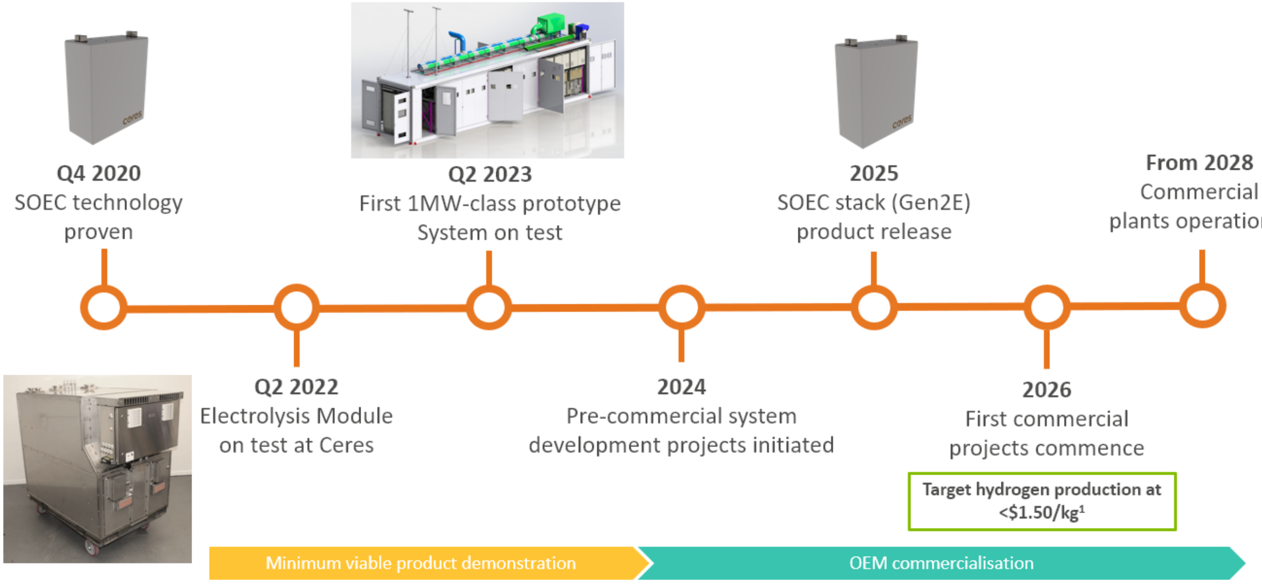


Figure 13- Technology Roadmap to SOEC Commercialisation

The next generation of cells will offer stacks produced specifically for electrolysis, with the first partner commercial electrolyser stack products available from 2025 and commercial systems available from 2028. As the manufacturing volume scale and the technology evolves, the cost per stack will drop significantly, allowing the production of GW scale electrolysis plants (Figure 14).

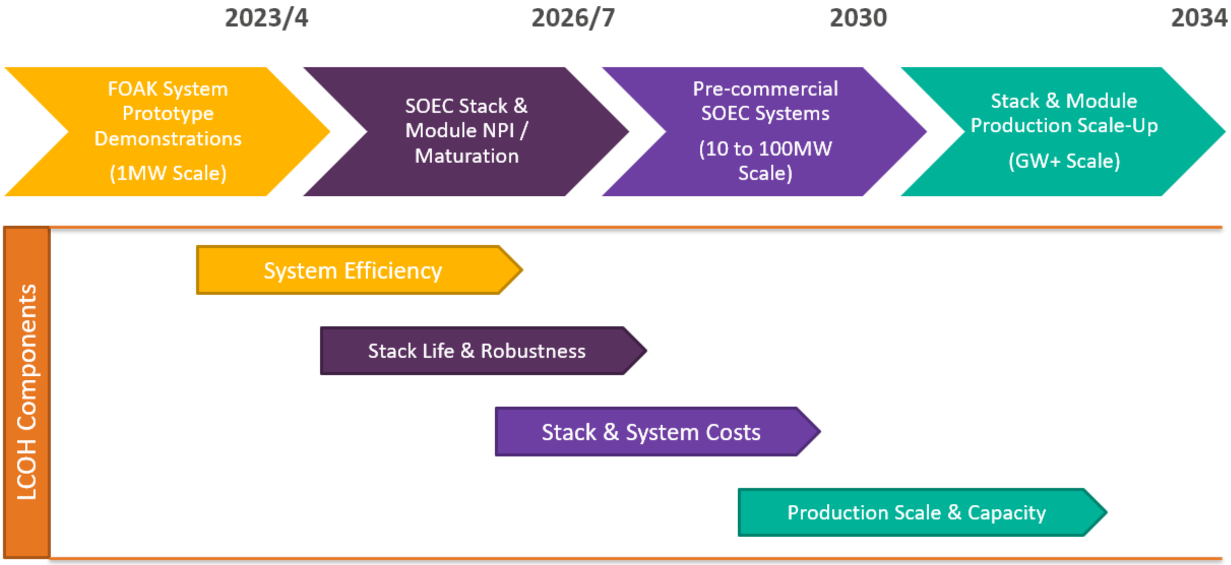


Figure 14- Roadmap to SOEC Commercialisation

4.1.2. Competitive Differentiation of SOEC Technology

Ceres SOEC operates at much lower temperature than ceramic / cermet supported high temperature solid oxide Ni:YSZ technology. Lower temperature operation allows a steel substrate construction that brings twin benefits of low cost and robust structures. The robustness comes from the higher fracture toughness of metal supports over ceramic or cermet supports. Further robustness comes from the welded cell assembly on the fuel side instead of relying on glass seals which tend to embrittle over time and may lead to serious leaks later in life.

SOEC is unmatched in efficiency / net energy consumption compared to PEM, Alkaline and Anion Exchange Membrane (AEM). SOEC is the only technology capable of integrating steam as a direct feedstock, allowing the use of the high-quality steam feed available from nuclear plants. As shown in Figure 15, SOEC technology efficiency is in the range of 75 – 95% depending on the level of steam and heat integration, reducing electrical power requirements down to 35kWh/kg hydrogen.

This makes a compelling case for coupling with nuclear power where a low carbon steam source is available 24/7 to achieve the high efficiencies and high yield of hydrogen per unit of energy input. With this approach, SOEC significantly outperforms any low temperature technologies delivering lower Total cost of Ownership (TCO), producing about 30% more hydrogen when operating on the same electrical capacity or delivering the same volume of hydrogen with only 2/3 of the electrical power needed.

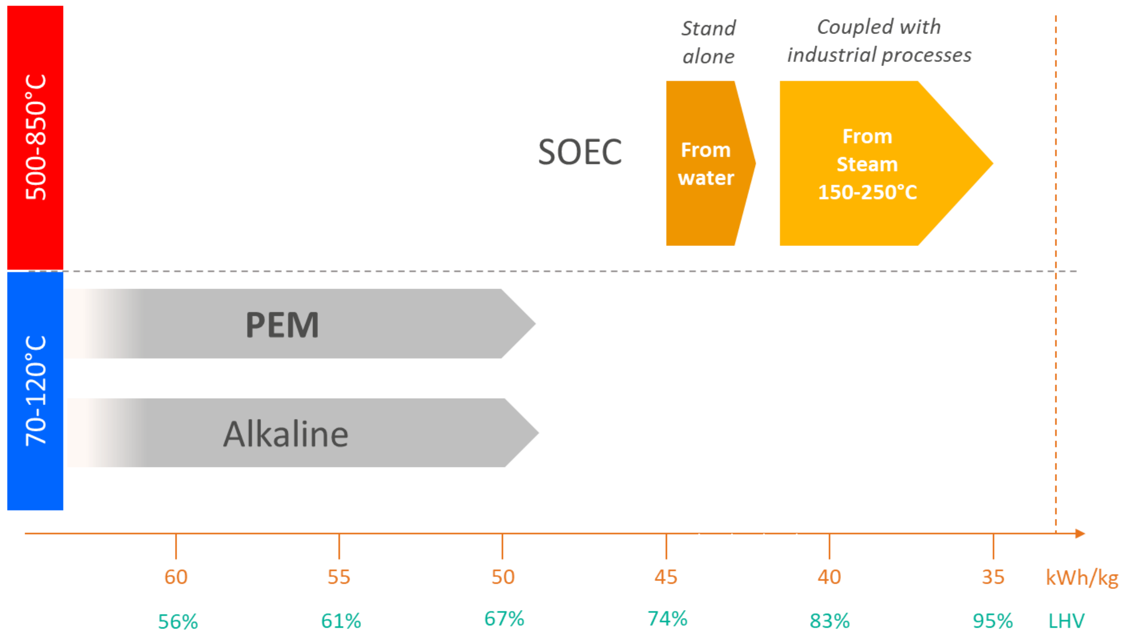


Figure 15- Efficiency and Hydrogen Output for Electrolyser Technologies

With less low carbon electricity needed, the overall cost of infrastructure is lower including transformer, converter, transmission lines, switchgear to electrical component specification and electrical storage capacity as considered required.

4.1.3. Durability and Life

Robustness has been demonstrated through many years of SOFC operation with hundreds of stacks across hundreds of systems. The robustness is characterised by long-term stability, tolerance to on/off cycles, load cycles and system fault conditions (emergency stop cycles, resulting in RedOx conditions). The SOEC architecture is fundamentally the same as SOFC with robustness characteristics maintained. Testing the cells in SOEC mode has shown that the degradation rate (shown in Figure 16) is comparable to Ceres' technology in SOFC mode.

Ceres SOEC can be operated in load following mode through operational excellence and robust design.

KEY FINDING

The long-term stability and tolerance to on/off cycling could make the Ceres SOEC technology an excellent partner to nuclear energy by enabling frequent and rapid ramping of electrical output to the national grid to compensate for the variability of renewables.

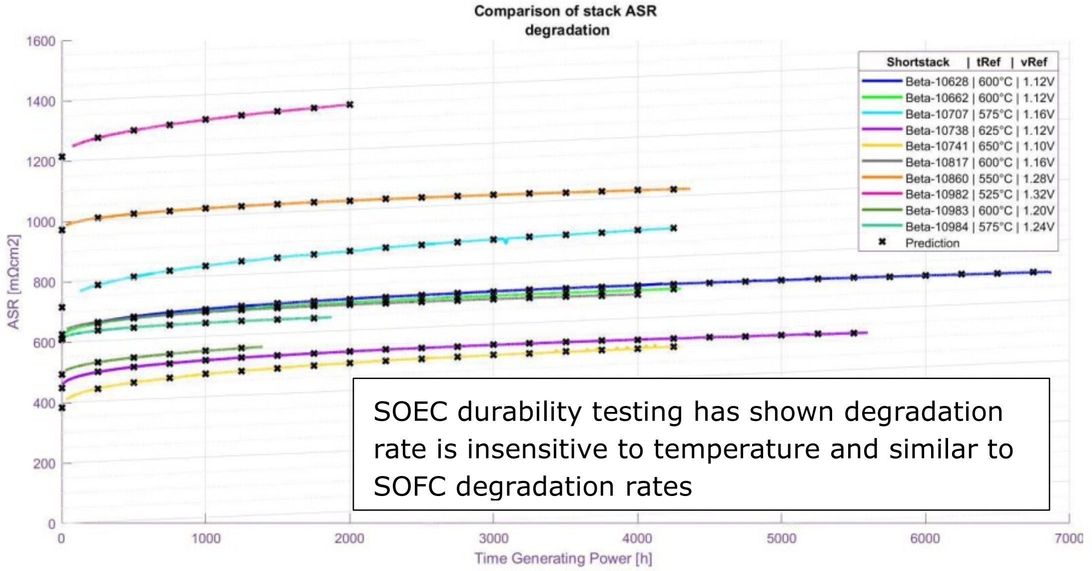


Figure 16- Comparison of SOEC degradation for a range of cell temperatures

Ceres first SOEC stack product is targeting 60,000 hours (6.85 years) of continuous operation with constant hydrogen production rate and efficiency. Through life, the cell Area Specific Resistance (ASR) slowly increases at a constant operating temperature. Due to the wide operating temperature of the SteelCell, degradation can be compensated for by increasing the operating temperature though life to enable constant electrical power in and constant hydrogen output shown in Figure 17. This ensures simplicity and low cost of plant operation.

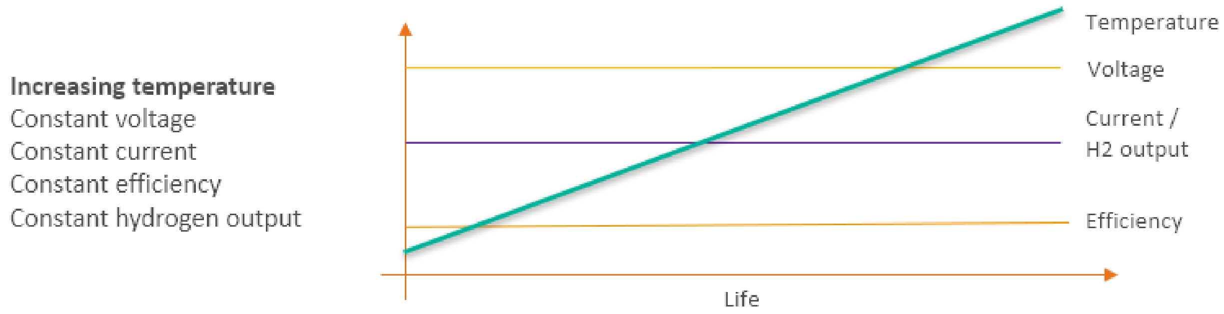


Figure 17- Representation of increasing the operating temperature of SOEC to maintain hydrogen output

Alternative control strategies and technologies require either oversized power supplies or oversized electrolyser capacities to meet the required hydrogen outputs as the electrolyser performance degrades.

4.1.4. Material and Recyclability

Ceres use a proprietary process to deposit very thin ceramic layers on the micro-perforated steel plates to form the perovskite cathode, CGO electrolyte and ceria-nickel cermet anode as shown in Figure 18. All materials in the cell are abundant in high volume manufacture, available from several suppliers.

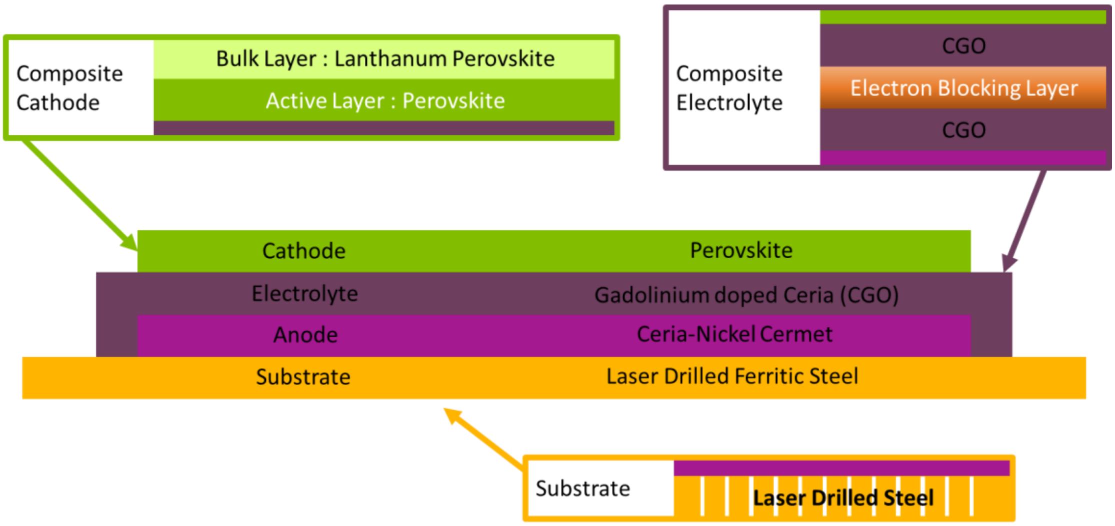


Figure 18- Representation of ceramic layers onto micro-perforated steel plate in SOEC

As discussed above in 3.2.1, the stack is easily recyclable because of the high steel percentage, stainless steel is >95% of the stack material content by mass.

4.2. Impact of Nuclear Enabled Hydrogen on demand for nuclear

As we move away from fossil fuels for heat, transportation and electricity generation, energy systems around the world need to rely on new energy sources, utilised in new ways. It is increasingly likely that hydrogen will have a key role to play in our low carbon future, so ensuring sufficient hydrogen generation capacity, and consequently sufficient energy generating capacity is essential. The options are limited with renewables and thus nuclear and the use of fossil fuels with carbon capture and storage will play a significant part in supporting future energy demands.

NNL, working with Energy Systems Catapult (ESC) and Lucid Catalyst, produced "UK Energy system modelling: Net Zero 2050"[26] a report presenting modelling work of nuclear deployment scenarios to support Net Zero. Within this report an installed electrical generating capacity of ca. 140 GW is presented with contribution from nuclear in the region of 40-70 GW.

Nuclear offers the potential for highly efficient hydrogen generation and importantly provides a cost-effective means for nuclear to provide flexible electricity; adjusting the proportions of hydrogen and electricity production to meet user demands at a particular moment. In this way, vector switching could also have a key role in meeting electricity demand, for example in winter evenings when there is no wind or sun and depleted storage. Equally in mid-summer when electricity demand is lower and may be met by renewables, there could be the opportunity for hydrogen to be produced and stored to supply directly as a fuel or burned to produce electricity or heat.

Today, heat demand for industry is predominantly provided by natural gas (top half of Figure 19) with the majority of applications demanding heat in the range 250°C to 900°C. One potential role for nuclear is to provide direct heat from the reactor secondary systems and the bottom half of Figure 19 shows that this could be possible in terms of the temperature demand. The coupling of nuclear to hydrogen production also enables flexible decarbonisation solutions where the points of hydrogen production and use are remote from each other.

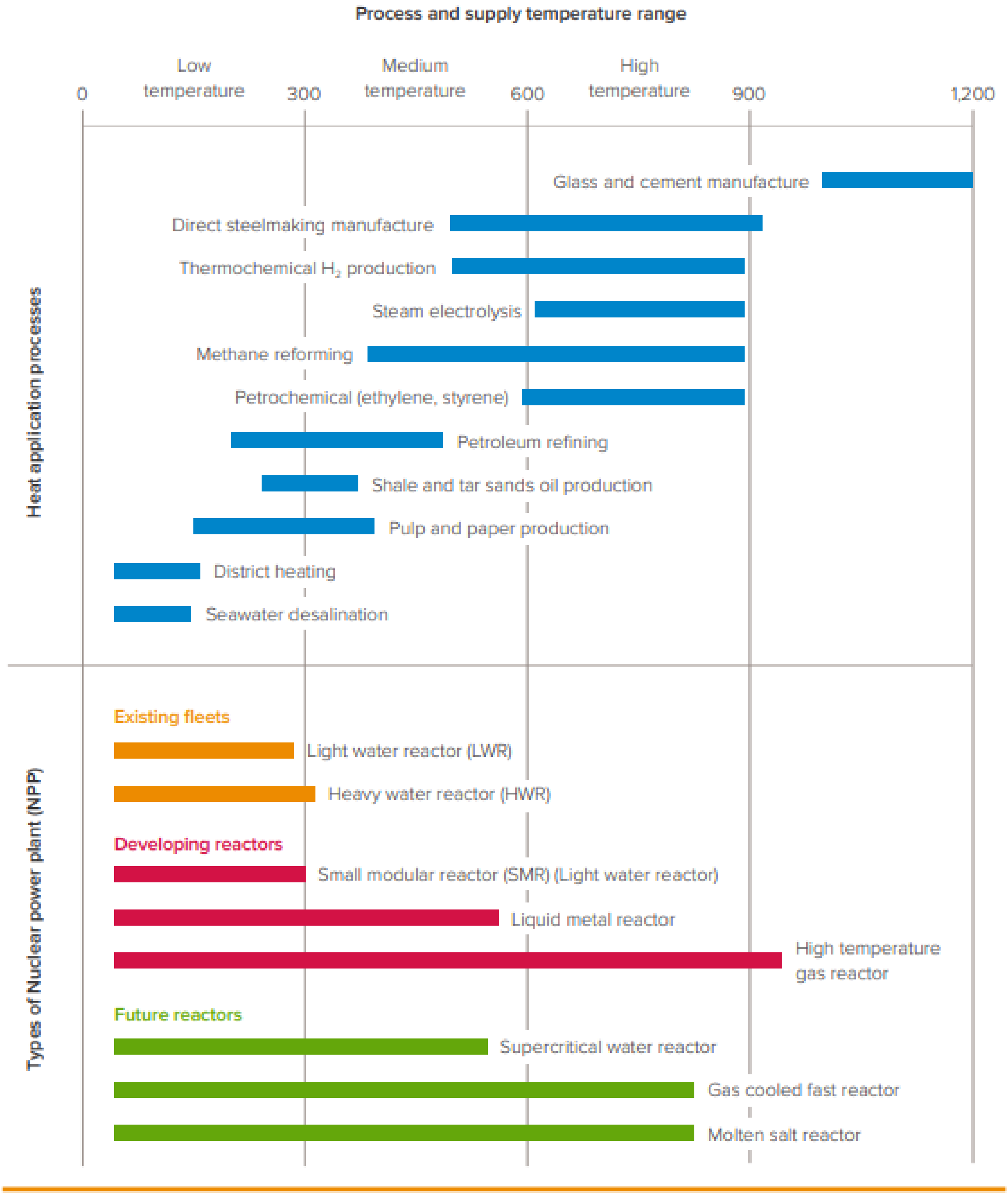


Figure 19- Heat applications and nuclear technology comparison[27,ii]

[ii] It should be noted the Ceres steam electrolysis technology considered in this report is differentiated from other SOEC technology as, rather than having a ceramic supported structure, it has a steel support. This has robustness advantages and, rather than operating at 600 – 900°C, it can operate at lower temperature, 530 – 630°C, giving a system cost advantage through lower cost material requirements.

The potential applications for nuclear will not only be determined by technical and economic viability, but also the timing of how the demand and supply grow in tandem according to technology developments by hydrogen users and ability to deploy new infrastructure on the supply side.

Cross-comparing the expected increase in hydrogen demand with technology and deployment opportunities for nuclear (Figure 20 and Figure 21) shows that the timelines could align well; in particular nuclear enabled hydrogen production capacity could be available to meet a demand increase in the late 2030s.

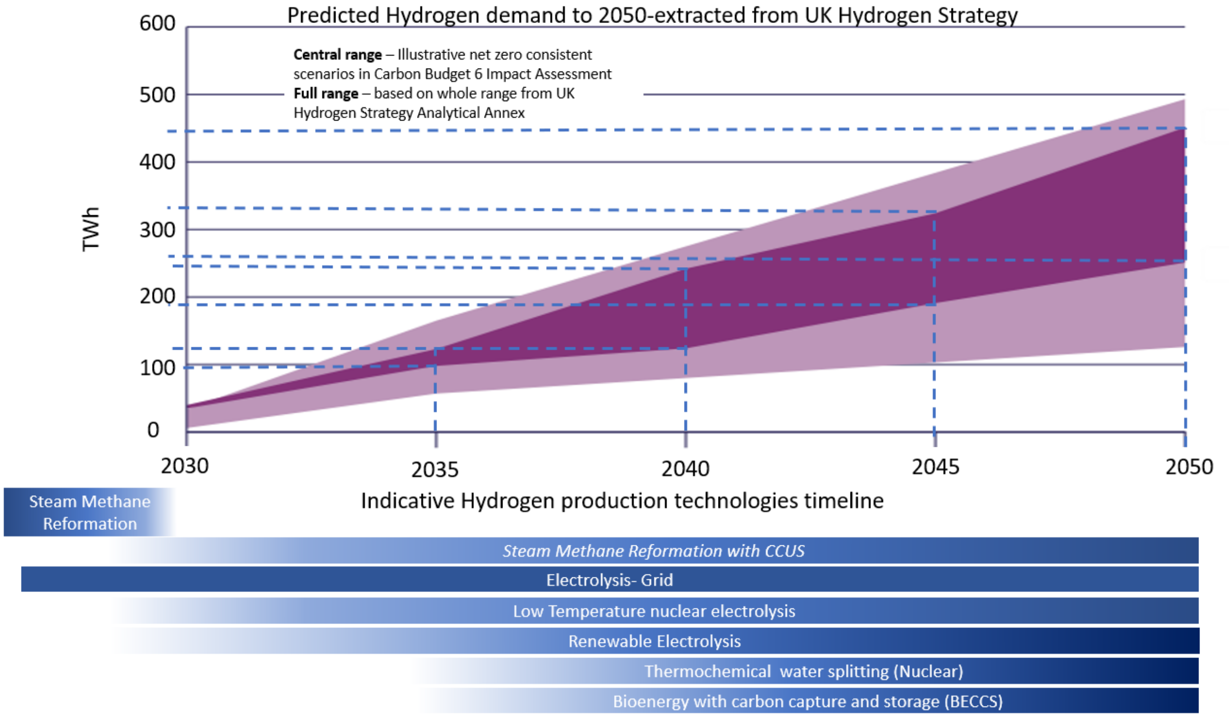


Figure 20- Timeline of anticipated hydrogen demand and hydrogen production technologies[28]

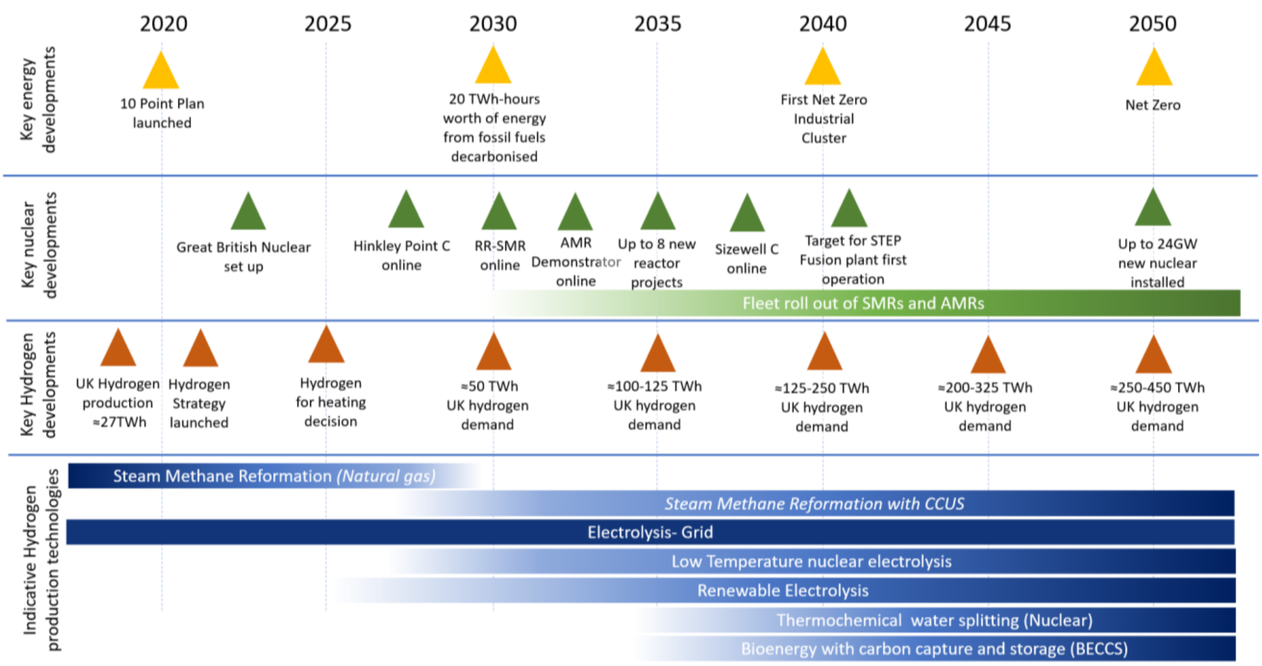


Figure 21- Timeline of key developments and hydrogen production technologies[28]

Timing has also been recognised as an important consideration by the UK Hydrogen and Fuel Cell Association (HFCA), who released 'The role for Nuclear-Enabled Hydrogen in delivering Net Zero' in June 2022. The document outlines a position that there is a potential demand for 20 GW of nuclear-enabled hydrogen production in 2040, and 40 GW in 2050 (Figure 22).

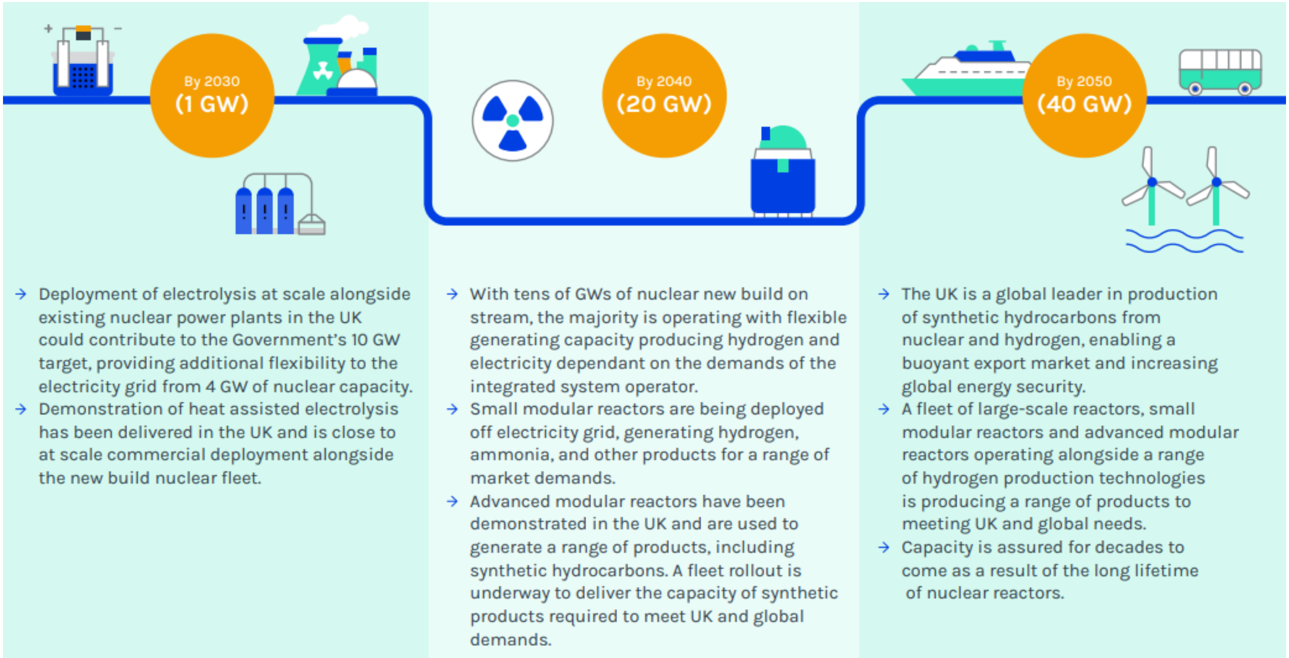


Figure 22- A vision for nuclear enabled hydrogen roll-out in the UK as presented by the UK HFCA[29]

KEY FINDING

The anticipated ramp up of hydrogen demand in the 2030s aligns well with the nuclear and hydrogen production technology developments and roll out.

4.3. Siting of New Nuclear

The current Government position on the siting of new reactors is outlined in the National Policy Statement EN6[30]. This identifies sites that could legally be considered for new nuclear development. However, there are potentially many more sites that could be suitable for development that fall outside the current legislative framework, examples include brownfield sites, or those areas currently devoted to fossil fuel refining.

Consideration of additional sites may also present major regional social and economic benefits in support of national priorities on levelling up as set out in the Government's White Paper[31] of February 2022, which seeks 'to spread opportunity more equally across the UK'.

Today, civil nuclear power stations are typically sited near the coast due to the need for access to large volumes of cooling water. Newer and modular next generation reactors could use air cooling and passive convection to permit much more flexibility in siting without the need for large water bodies nearby. This could allow nuclear heat to be placed near demanders of high temperature heat for hard-to-abate processes such as aggregate and cement manufacture.

There is a need therefore to consider siting holistically considering:

- The technology needs of future systems
- The need for hydrogen production in a wider range of locations, potentially nearer to the point of use
- The co-location of nuclear and hydrogen production
- The social and economic benefits that nuclear could provide across the UK
- Legislative and regulatory constraints and opportunities

4.3.1. User Demand Locations[iii]

This study considers the viability of decarbonising Hanson asphalt and cement manufacture operations with hydrogen generated from nuclear.

Hanson operates 34 asphalt sites, three clinker producing sites with cement kilns and three grinding plants with burners to dry raw materials across the UK. The majority of the Hanson sites are not connected to the UK natural gas network due to the current price of using the

[iii] The Hanson data presented in this section is taken from the project file 'List of questions to Hanson (WP5 WP6) 10112022 (002) v2' provided by Hanson on 02/12/2022

network compared to road transport. The total thermal demand at the Hanson asphalt sites is 384 GWh per year, with the two highest demand sites consuming 75 GWh per year.

In consultation with Hanson, none of their cement sites have gas grid connections and 6 of their asphalt sites have gas grid connections. The ease and cost of connection to the gas network for their sites varies depending on location to the gas network and ranges from £100k to over £1m while on some sites gas network connections would not be possible due to their remote locations. This is visually shown in Figure 23 where coloured circles with numbers in and pins represent location of Hanson sites and the blue lines the high-pressure gas grid transmission.

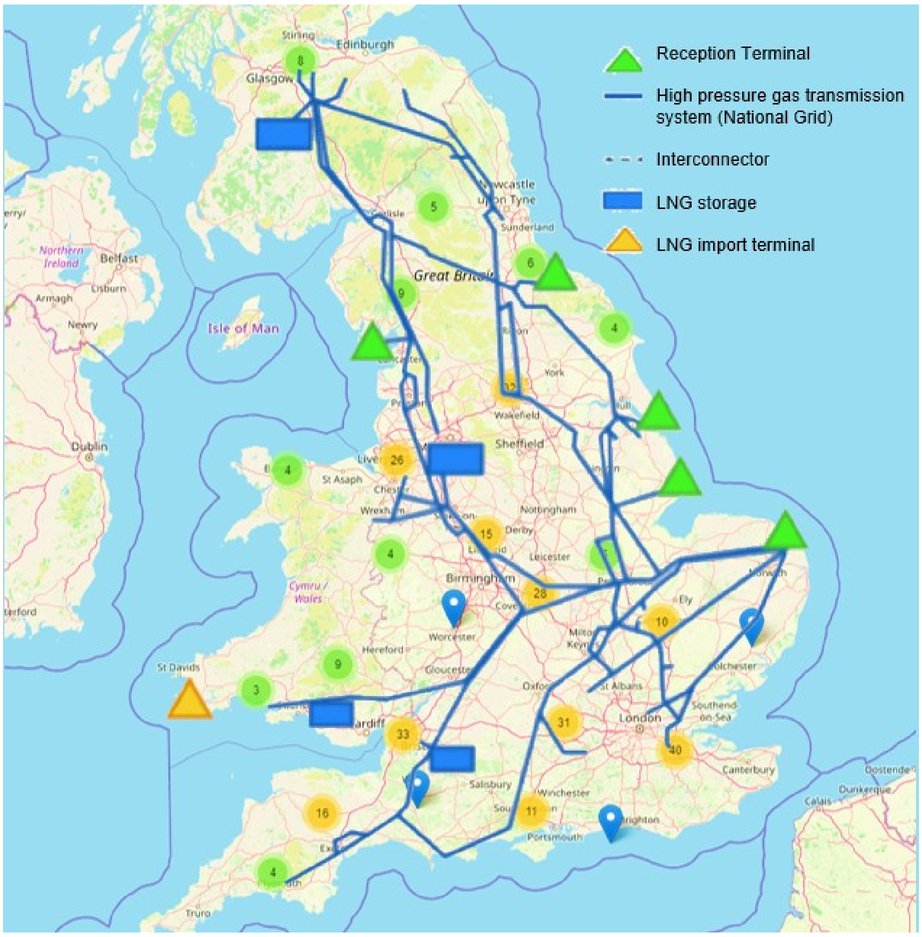


Figure 23- Overlay of National Gas Transmission Service[32] and Hanson Operation[33]. Note orange circled numbers represent a higher density of Hanson operations in that region

Total thermal energy demand for Hanson cement plants is ~2,400 GWh annually, however, the amount of hydrogen that can be used in cement is unknown. Discussions with Hanson have suggested a working assumption that 10% of the total energy (240 GWh) could come from hydrogen combustion.

As shared above, the total thermal energy demand for Hanson asphalt plants is 384 GWh annually and it is assumed that these can operate on 100% hydrogen burners.

In total, the potential thermal energy demand equates to 624 GWh and assuming that there is 100% conversion of hydrogen stored energy content to heat, this places a requirement for hydrogen to the same 624 GWh level. Taking into account electrolyser efficiency losses, nuclear operating capacity factor and the thermal efficiency of electricity generation, this places a requirement on nuclear deployment capacity of approximately 260 MW_{th}. Considering that this power requirement is one quarter of the thermal energy output from a Rolls-Royce SMR (RR-SMR) and that this total requirement is disparate, it could be that nuclear reactor units with smaller power outputs such as the Urenco U-Battery would be better suited to meet demands of specific sites.

For asphalt and cement facilities there are a limited number of opportunities to relocate operations, as some key resources e.g. quarries, are fundamentally immovable. The Concrete and Cement decarbonisation roadmap[34] suggests however that there are opportunities that could be met with electrification, for example plasma arc melting. In the case that nuclear power is used to run production technologies which rely on both electricity and heat (e.g. steam electrolysis) then there is the opportunity to provide a direct line of electricity for these operation with nuclear providing the decarbonisation through electricity instead of hydrogen.

It should be noted Hanson have a range of publications focusing on their commitment to reach Net Zero by 2050 including their Cement & Concrete Road map[35], Asphalt road map[36] and Aggregates road map[37]. While these publications consider the role hydrogen can play, they do not consider the potential role of nuclear, so there is a future opportunity provided by this work.

KEY FINDING

The total energy demand for hydrogen by Hanson of 624 GWh would equate to approximately 260 MW_{th} of nuclear capacity. This is approximately one quarter of the output from a RR-SMR or 26 U-Battery systems. Therefore, using nuclear energy, one RR-SMR operating constantly producing hydrogen could provide all of Hanson's hydrogen energy requirements for decarbonisation four times over.

4.3.2. Potential sites

The Energy Technologies Institute (ETI) completed a study in 2015 to assess how the UK may be able to site the highest potential nuclear deployment (circa 75 GW) including the use of brownfield and greenfield sites, while avoiding environmentally protected areas, urban developments, and military sites. The work also considered sites that could potentially host a nuclear demonstrator[38].

To reach the theoretical 75 GW deployment scenario proposed, further sites not noted in the National Policy Statement (NPS) were incrementally added based on certain geographic and demographic criteria. The summary of the findings is shown in Table 1, which underlines the potential opportunity that the UK has for new build development beyond that noted in the NPS, should a suitable user demand profile be forthcoming.

Table 1 shows current UK nuclear licensed sites along with other sites that were considered on the 'long list' in the ETI report. These are sites that in theory could have the appropriate access to land and water to host either a large or small nuclear power station, or both. The ETI study makes no claims as to the potential to secure the appropriate permits and licences for building and operating at these locations. However, some have greater potential than others. The work started with the assumption that existing nuclear sites offer the easiest route for new build, particularly as changes to legislation would be needed to build on the brownfield sites. Greenfield sites, by comparison, would in most cases require modification of infrastructure (roads, retail/ health provision) around the site to enable a workforce to build and operate the reactor. The impact of the additional siting options is set out in Table 1, demonstrating a route to 75 GW_e of deployed generating capacity.

Table 1- ETI calculations of potential nuclear capacity with varying deployment scenarios[38]

	Description	Additional potential capacity	Total potential additional capacity
1	New nuclear development for large units next to existing nuclear licensed sites in England and Wales	23.65 GWe	23.65 GWe
2	Including development at brownfield and greenfield sites	13.2 GWe	36.85 GWe
3	Deployment beyond large twin units (i.e. at more than 2.5 – 3.5 GWe per site) next to existing nuclear licensed sites	14.85 GWe	51.7 GWe
4	Adding 300 MW_e units next to existing nuclear licensed sites	2.1 GWe	56.8 GWe
5	Adding 300 MW_e units at brownfield and greenfield sites	8.4 GWe	65.2 GWe
6	Including 300 MW_e units in brownfield and greenfield regions on independent water bodies	18 GWe	83.8 GWe

Within the British Energy Security Strategy (BESS)[7], the plans for 'deployment of civil nuclear to 24GW_e by 2050 (25% of our projected electricity demand)' is presented. Corelating this to the ETI study results as presented in Table 1 it can be seen this could be achieved using suitable land next to existing nuclear licensed sites (rows 1 and 4) with a very significant potential to consider additional deployment to other locations.

The BESS aligns nuclear deployment to electricity production alone and it is highly probable that renewable generation and energy storage will increase in deployment over the coming decades requiring nuclear to operate flexibly and achieve higher deployment to meet demand for alternative energy vectors. This could mean changing the proportions of electricity and hydrogen production to compensate for renewable output and storage limits.

As can be seen in Figure 24, all past and current UK nuclear reactor sites (with the exception of Trawsfynydd) are by the coast. If this remained the case in the future, then there is an obvious requirement to use hydrogen transport and distribution networks to supply hydrogen users that are in land. However, newer nuclear technologies with smaller power outputs could more readily be sited in land (perhaps on sites identified by ETI), to bring the hydrogen generation closer to the point of use.

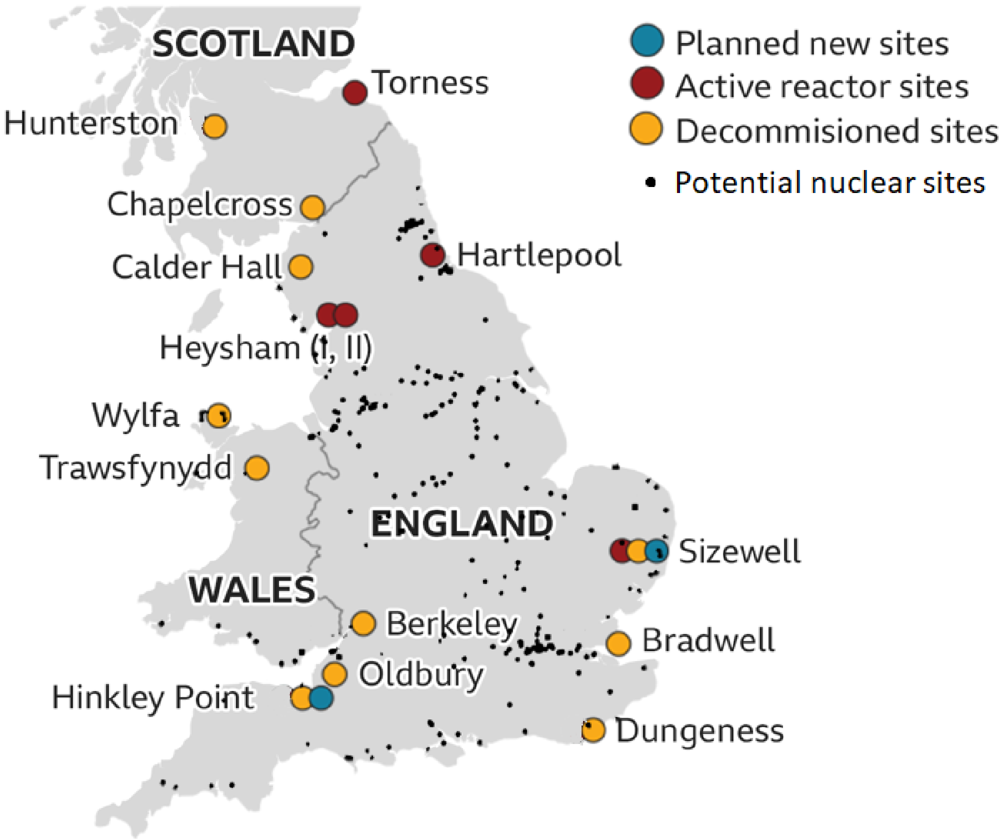


Figure 24- ETI Study Selected Sites[38] Cross-Compared with current UK Nuclear Sites[39]

KEY FINDING

The Energy Technologies Institute study indicates a potential nuclear capacity across the UK of 83.8 GW_e, this includes the use of development next to existing nuclear sites through to the use of brownfield and greenfield sites. While significant work would be required to enable all of these sites, this study indicates siting does not need to be a constraint to capacity.

4.3.3. Aligning Production Locations with Demand

Figure 25 below overlays Hanson sites, current nuclear reactor sites and the long list of potential nuclear sites (black dots) from the ETI siting study. The purpose is to consider whether production of hydrogen from nuclear energy may be possible in the vicinity of the Hanson sites to reduce the reliance on long distance transportation and distribution of hydrogen. This comparison is helpful to consider options for future deployment and alignment between nuclear siting policy and Hanson operations.

Firstly, the ETI study does not include specific postcode locations, so at this time it is not possible to assess whether co-location might be possible with the current siting considerations. Moreover, the ETI study did not consider any additional requirements (for example access to water) that producing hydrogen on each potential site might place. Therefore, with the current information available and the prevailing nuclear deployment policy, it is likely that road transport or gas network distribution of hydrogen to Hanson sites would be the preferred method of supply in the nearer term. This decouples the siting issues around Hanson sites and potential nuclear deployment sites.

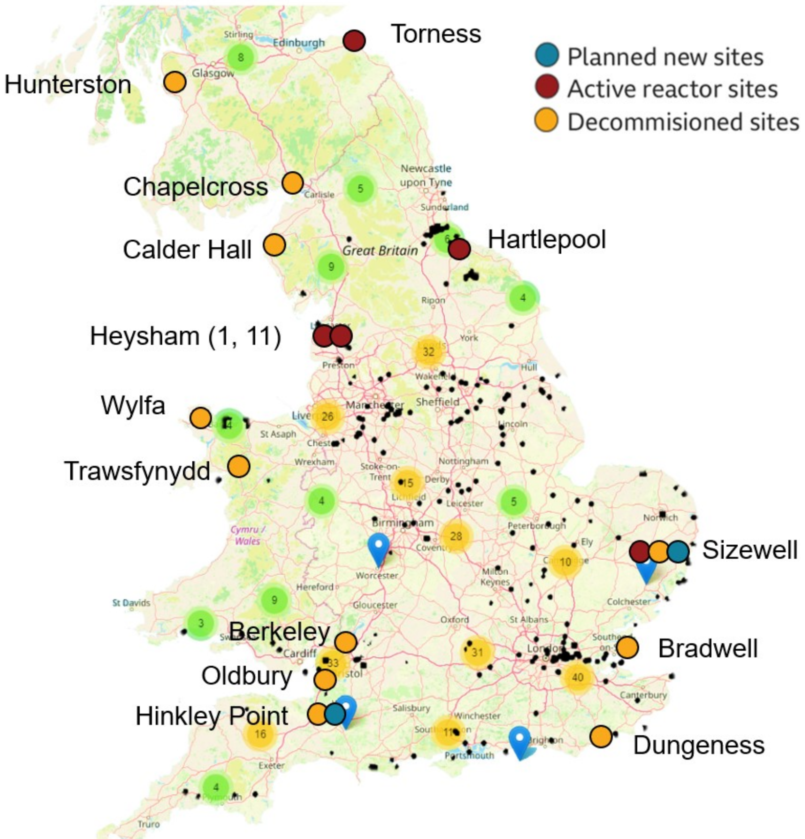


Figure 25- Overlay ETI[38] 'long list' of potential nuclear licensed sites, current nuclear sites[39] and Hanson Operations[33]. Black dots indicate sites on the ETI 'long list' of potential sites. Pins and coloured circles indicate Hanson operations

Early work in the costs of hydrogen transport suggest that domestically produced hydrogen would have an associated transportation cost on the order of £0.20/kg H_2 (gaseous) within the UK[40], and so suggests while there is a competitive advantage to site reactors closer to demanders, it is not the limiting factor on siting.

In the longer term, the potential of future technologies to extend the possible deployment sites further could widen the options for co-location of hydrogen production and use. Future technologies, such as AMRs, are expected to include inherent safety features that enable reactors to be located much closer to industry and population centres, and their cooling system designs may reduce or remove the need for them to be located near large bodies of water.

For the purposes of longer-term solutions co-location of Hanson sites with nuclear sites generating heat and hydrogen should remain under review in respect of:

1. At such time that siting policies are reviewed, consider the potential for co-location.
2. Consider future technologies and the potential for co-location on a timescale that aligns availability of these technologies with the need to decarbonise.
3. When Hanson are developing new locations, or relocation of current operations, consider whether locating these near to potential nuclear generation sites would be possible.

KEY FINDING

In the near term it is likely that the supply of nuclear enabled hydrogen to Hanson sites will be reliant on hydrogen transport and distribution networks. In the longer term, the potential for co-location, particularly considering future technologies with more flexible siting requirements should remain under review.

4.3.3.1. Distribution through a future hydrogen gas network

Currently, a range of projects are ongoing across the UK considering the potential transition of the UK gas network to hydrogen. As part of this, NNL has undertaken work with DNV looking at 'Nuclear-Derived Hydrogen to Gas Networks'[41]. The purpose of the project was to develop evidence to support the government policy decisions on the role of hydrogen in buildings and for heating, scheduled for 2026.

Under the BEIS funded Advanced Nuclear Skills and Innovation Campus (ANSIC) NNL with DNV collaborated on a first-of-a-kind project to bring the nuclear and gas network sectors together, exploring the potential for hydrogen produced from nuclear energy to be transported and distributed to end users through a converted hydrogen gas network.

Overall, the project found that there are no showstoppers to nuclear enabled hydrogen being injected to the gas network.

The findings of the report provided policymakers and energy system stakeholders, including National Grid and the Gas Distribution Networks (GDNs), with a heightened level of confidence that nuclear could be deployed to support transition of the gas networks to hydrogen.

> KEY FINDING
>
> The distribution of hydrogen to Hanson sites through a converted hydrogen gas distribution network presents a potential option subject to economic and location considerations.

The main findings were that much of the UK gas network is already compatible with a hydrogen-only feedstock or on track to be compatible through routine asset maintenance. It is also found that storage requires innovative solutions as the volume of hydrogen required to displace natural gas is far greater, due to calorific value and thus current line packing and other current storage solutions would not offer sufficient storage potential.

When considering the potential use of the national gas grid to provide hydrogen directly to the Hanson sites, Figure 23 above provided an overlay of the groupings of Hanson sites (coloured circles with numbers in and pins) and the national gas transmission service. It may be possible for further Hanson sites to connect to the gas grid and any decision on this would be based in part on economics. Currently there are many Hanson sites where trailering delivery of fuel is the preferred supply option from an economic perspective, but the bias may change for hydrogen, which is potentially more costly to transport.

> KEY FINDING
>
> Most of the national gas grid in the UK is already compatible with hydrogen and there are no showstoppers for injection of nuclear derived hydrogen into the gas grid. The area requiring development is storage, due to the larger volumes of hydrogen required compared to natural gas.

4.3.4. Storage considerations with siting

While just-in-time hydrogen supply could be considered the ideal goal, it is possible that a more resilient solution while the technology is developing, is one based on the provision and use of a large hydrogen store to smooth spikes in demand against a smaller more consistent supply. This section explores how hydrogen storage solutions could help ensure a resilient and consistent supply of hydrogen to support decarbonising cement and asphalt manufacture, while also providing nuclear enabled hydrogen producers with a buffer for periods when the power stations enter outages for refuelling or maintenance. In this way, storage becomes an essential element of a system solution.

Hydrogen has a small atomic radius, a low boiling point and high volatility which makes storage challenging; the current state of the art to economically transport hydrogen is to compress hydrogen into either a gas or a liquid and requires specially insulated tanks. Research into future hydrogen storage technologies are looking towards solid storage. One example of this is EDF's current work on metal hydrides[42], in which hydrogen is absorbed on a depleted uranium 'bed', which can then release the hydrogen when needed for use. When stored, the hydrogen is in a stable but reversible 'metal hydride' form.

Another more developed option is hydrogen storage in salt caverns, a demonstrated solution of low cost and high efficiency due to their extremely suitable characteristics. The halite (rock salt) that makes up salt caverns is viscoplastic, self-healing and gas tight. Unlike other technologies both the construction and operation of salt cavern for hydrogen storage is well developed. The UK is home to the world's oldest salt cavern hydrogen storage facility in Teesside which opened in 1972 and has a capacity of 3 caverns at 70,000 m^3 each.[43] The UK has a number of salt caverns especially over the North West, the British Geological Society estimate that there is 284 TWh potential for hydrogen storage caverns in the Cheshire Salt basin alone[43], while this number is indicative and does not take into account the economic or social feasibility of the creation of salt caverns, this storage alone is almost equal to the whole UK electricity demand for a year.

In 2022 the Journal of Energy Storage presented the paper "Does the United Kingdom have sufficient geological storage capacity to support a hydrogen economy?"[44] which explored the use of salt caverns as the only commercially proven subsurface storage technology implemented at scale. Within the paper it calculates the UK has a potential hydrogen storage capacity exceeding 64 million tonnes, providing 2,150 TWh of storage capacity within the salt basins. The analysis indicates that the availability of salt cavern storage potential does not present a limiting constraint for the development of a low-carbon hydrogen network in the UK.

A key consideration with salt cavern storage is location, as shown in Figure 26, the largest salt caverns are located in the North West and North East of England and thus a form of transport, be it trailer transportation or hydrogen gas grid, would be required to enable the sites not in the north to benefit salt cavern hydrogen storage.

Figure 26- Comparison of Salt cavern locations[45] and Hanson sites[33]

> KEY FINDING
>
> The UK operates the world's oldest salt cavern hydrogen storage facility in Teesside which opened in 1972. Salt cavern storage is the most developed form of hydrogen storage with a potential for UK salt cavern hydrogen storage capacity of 2,150 TWh.

4.3.5. Land area considerations

Section 4.3.1 considers the nuclear capacity that could be required to decarbonise Hanson operations. The nuclear power capacity (approximately 260 MW_{th}) is not, on the scale of nuclear generation overall, a large requirement. However, should nuclear enabled hydrogen production be economically attractive in a wider range of circumstances, thereby requiring a much larger capacity, a key consideration becomes the amount of land that could be required.

The UK is relatively space limited and the study 'Missing Link to a Livable Climate' produced by Lucid Catalyst[46] calculated the area required to supply UK's current oil consumption with hydrogen from wind, solar, or advanced heat sources such as Advanced Modular Reactors (AMRs). Compared to land area required for AMRs (55 km^2 / 13,600 acres), an area 474 times would be required for solar or 2,474 times for offshore wind, clearly showing the significant energy density and thus smaller footprint required from nuclear energy. For comparison, Table 2 provides the land area for the 6 currently operational oil refineries in the UK.

Table 2- Land area of UK oil refineries

Refinery	Land area	Source
Humber	480 acres	https://www.phillips66.com/refining/humber-refinery/
Lindsey Oil	500 acres	https://prax.com/prax-lor/
Fawley	3,250 acres	https://www.exxonmobil.co.uk/-/media/unitedkingdom/files/fawley/fact-sheet-and-brochure/exxon-fawley-fact-sheet-2022.pdf
Grangemouth	1,700 acres	https://www.ineos.com/sites/grangemouth/about/
Stanlow	770 hectare (1,900 acres)	http://www.essaroil.co.uk/our-work/stanlow/
Pembroke	450 acres	https://texaco.co.uk/Pages/NewsArticles/Texaco-are-proud-to-be-made-in-wales.aspx
Total	8280 acres ($33.5\ km^2$)	

Using Lucid Catalyst's calculations that 13,600 acres of land area from AMRs would be required to produce all the hydrogen to replace current oil consumption, that equates to approximately 1.6 times the current oil refinery land area in the UK.

While a number of assumptions have been made in the Lucid Catalyst work, and the land area required will vary based on a number of factors such as: type of nuclear reactor; hydrogen production technology; operating capacity factor; proportion of current oil consumption transitioning to hydrogen (compared to electrification/ efficiency savings); as an indicative calculation, the scale of land area required for nuclear reactors to meet the hydrogen demand to replace oil is comparable to the area of the UK's current refineries.

KEY FINDING

The total land area required to replace the UKs current oil consumption with hydrogen generated from nuclear energy is ~$55km^2$, which equates to approximately 1.6 times the land area of the UK's current oil refineries.

5. Future Hydrogen Economics

For sectors reliant on hydrogen for their decarbonisation, the price at which the gas can be sold to a wider energy market will directly impact the speed of transition for hard-to-abate industries towards Net Zero. Calculating the lifecycle cost of hydrogen, however, is complex and depends not only on the capital and operational costs, but also on plant financing costs, and the cost of hydrogen storage and distribution.

Future nuclear projects are targeting cost reductions through a number of routes, including increased factory production, reduced construction schedules, plant design simplification, and learning from building multiple units. Cost reductions for nuclear alongside expected capital cost reductions of electrolysers therefore present an opportunity to improve the competitiveness of clean hydrogen in a future energy system. Furthermore, integration of reactor heat into SOECs should deliver a further cost reduction per unit of hydrogen.

Innovative financing models, such as the Regulated Asset Base (RAB) model, aim to significantly decrease financing costs for capital intensive nuclear projects, attracting private sector investment. NNL previously published a high-level estimate to the cost of GW scale nuclear enabled hydrogen using a modern financing model[47].

This section explores aspects which impact the economic viability of nuclear enabled hydrogen to provide an updated estimate to the cost of nuclear enabled hydrogen using an AMR and SMR deployment scenarios with advanced funding arrangements as well as heat inputs to electrolysers.

5.1. Factors Affecting Economic viability of Nuclear Enabled Hydrogen

To be successful for use as an energy vector, nuclear enabled hydrogen will need to be competitive with other low-carbon energy options. The main hydrogen production technology competitors are the thermochemical methods to split methane with carbon capture and storage (e.g. autothermal reformation and steam methane reformation), and the electrolysis of water using renewable energy (e.g. alkaline, PEM, and SOEC).

The factors which influence the cost of one hydrogen production option relative to another include:

- The Levelised Cost of Electricity (LCOE) or Levelised Cost of Heat (LCOHt) supplying the hydrogen production technology
- The Capital Expenditure (CAPEX) and Operational Expenditure (OPEX) of the hydrogen production technology
- The efficiency of the hydrogen production technology
- Transportation and distribution costs
- Financing arrangements

However, this also needs to be balanced with the practicalities of deploying the necessary infrastructure, in appropriate locations and connected through various means to the hydrogen users.

5.1.1. LCOE or LCOHt of Energy Production Technology

The levelised cost of the energy source which supplies the hydrogen production facility forms a significant part of the cost of hydrogen. This value varies by the technology and the environment in which it is built and is governed by the CAPEX and OPEX cost for the energy production facility, the efficiency of the technology and the financing arrangements surrounding the plant.

At present nuclear energy plays a key role in our energy system by providing highly reliable, low carbon electricity at a high capacity factor. Nuclear also offers a generation option which is less closely coupled to the marginal costs of the international energy market. It is expected through leveraging best practice in other sectors, learning-from-doing for the nuclear build and other innovation into an AMR or SMR deployment scenario that the LCOE or LCOHt can make nuclear a highly competitive option for fleet deployment based on economics alone. Estimates related to this are shown in Section 5.2.

KEY FINDING

AMR and SMR technologies have potential for decreases in LCOH via reduction of CAPEX and OPEX costs and because of their cogeneration capacity. High capacity factors provide a reliable power source suitable for continuous operation of hard-to-abate industries.

5.1.2. Effects of Scale on Efficiency, CAPEX and OPEX Costs of a Hydrogen Production Technology

The LCOH from a nuclear enabled hydrogen facility will depend in a significant way on the cost to construct, commission and operate the hydrogen plant. At present hydrogen plants run on scales from 100 kW to tens of MWs. An AMR or SMR could provide 100s of MW, and GW scale nuclear in the order of 1000s of MW, of thermal and electrical output, which will be an unprecedented generating capacity for the UK's hydrogen supply chain to couple electrolysis production technology to.

A scale up in UK hydrogen supply provides an opportunity to optimise the performance of hydrogen production technologies through learning by doing, but also to bring in innovation in the operation of plants at scales that have not typically been demonstrated to date.

BEIS data[48] suggests that conventional alkaline methods are highly mature with limited opportunity for cost reduction, while cost reduction can be expected for the less mature PEM and steam electrolysis hydrogen production methods. In the medium term, steam electrolysis is anticipated to have the overall best performance and looks to outperform PEM in the 2030s, for a given case. There is also the potential for new hydrogen technologies such as thermochemical hydrogen to compete in the longer term.

Overall, the factors which will influence the proportion of hydrogen production options in the UK are not clear at present, however in the near and mid-term the performance of both nuclear and steam electrolysis technology present an opportunity for the production of hydrogen at high-scale and favourable cost.

Further information on the opportunities and technical areas which could be improved for hydrogen production technology are explored in Section 3.2.

5.1.3. Transportation and Storage Costs

Hydrogen is a gas which has a lower volumetric density than natural gas which makes it comparatively less economical to transport. There are a range of options for transporting hydrogen including switching the UK natural gas network over to hydrogen for pipeline transport, or containerised land or sea transport.

Hydrogen is anticipated to be stored and transported as a compressed gas within the UK, and internationally as a liquid. Cryogenic freezing reduces the lifecycle efficacy of the energy vector in a substantial way (costing approximately ~30% of the enthalpy value of the fuel's combustion[49]) and so is not anticipated to be the preferred near term (domestic) hydrogen transport option. Conversion to other hydrogen carriers, such as methane and ammonia, for transportation, followed by re-conversion to hydrogen at destination is finding favour in some global economies.

At present only a proportion of the asphalt facilities within Hanson are supplied by natural gas. In the medium term, we anticipate that hydrogen would be transported to site via road transport and the full costs of this need to be captured in business and policy planning. Novel technologies for storage such as gel-based hydrogen storage or solid-state storage are currently early Technology Readiness Level (TRL) and so are not anticipated to be ready in the near-term for commercial (inactive) deployment, thus leaving compressed storage, and salt cavern storage as small-scale and large-scale storage options.

More discussion on the logistical considerations around hydrogen transport and storage can be found in Section 4.3.

5.1.4. Financing

Nuclear energy relative to other energy options currently has a higher installation cost per unit of generating capacity. Through learning-by-doing and good programme management in a fleet build scenario however there is the possibility of seeing large cost reductions which could improve market confidence in the technology.

Financing for nuclear energy additionally assumes a higher risk profile relative to other energy options due to historic cost and schedule overruns. This then inflates the cost of capital in comparison with other technologies which have greater market predictability. Modular reactors present the opportunity to save time and cost in a fleet build scenario and lower the risk associated with nuclear by investment markets.

Prior NNL work[47] complemented existing BEIS data for the LCOH for nuclear enabled hydrogen production using an alternative financing model known as the RAB model to reduce the overall cost of capital. Using an assumed GW scale plant, and nuclear electricity to power hydrogen production technologies, it was understood that under advanced financing (for example the incorporation of the RAB model) for GW scale builds would result in a reduction of the LCOH to a price competitive with renewable energy enabled hydrogen with a LCOH of approximately £75/MWh (2020£).

An update to this data is provided in Section 5.2 which considers the impact on LCOH that might be seen if SMR and AMR technology is deployed to use heat and electricity to produce hydrogen using SOE production methods.

5.2. Estimates for LCOH of AMR and SMR Technologies

This section presents an extension to the previous preliminary assessment for GW scale nuclear enabled hydrogen which includes calculations for the scenarios of AMR and SMR technology coupled with SOE hydrogen production technology. In order to generate an LCOH, a preliminary LCOE calculation is required for SMR and AMR technology which is detailed in Section 5.2.1.

LCOH Calculations have been completed considering two broad scenarios:

- A calculation estimating the LCOH for a FOAK SMR coupled SOE hydrogen production plant (using BEIS cost data)
- Calculations estimating the LCOH in a NOAK deployment scenario for SMR and AMR coupled SOE hydrogen production technology (using BEIS cost data)

An overview of the individual cases which are calculated are shown in Figure 27.

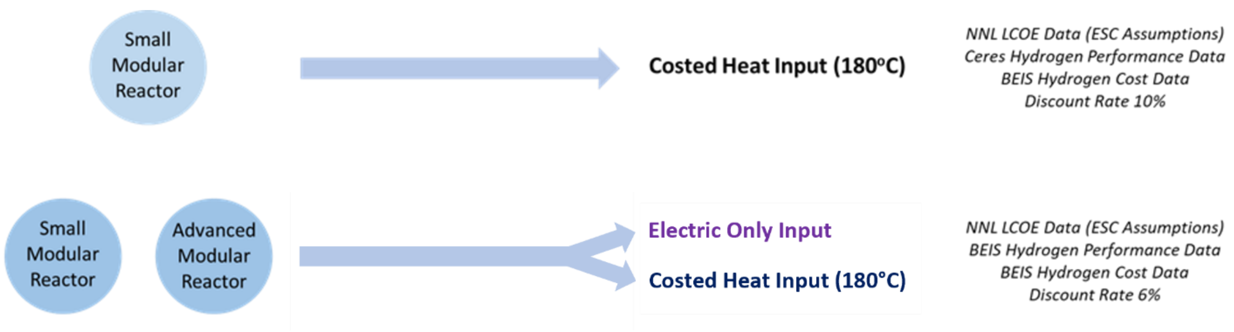


Figure 27- Overview of LCOH calculations completed for SMR and AMR technology

The methodology and assumptions employed to generate the LCOH in each case is presented in Section 5.2.2.

5.2.1. Estimates for LCOE and LCOHt of AMR and SMR Technologies

The LCOE and LCOHt of a light water SMR at 300MW$_e$ and a 600MW$_{th}$ AMR was calculated with Energy System Catapult assumptions,[50] using the methodology shown in Equation 1 for discount rates of 6% (representative of NOAK financing costs) and 10% (representative of FOAK financing costs). The methodology employed to generate a LCOE follows the BEIS method in the Electricity Generating Costs Report[51].

$$LCOE = \frac{Net\ Present\ Value\ of\ CAPEX\ Costs + Net\ Present\ Value\ of\ OPEX\ Costs}{Net\ Present\ Value\ of\ Electricity} \quad (1)$$

The LCOE data calculated using Equation 1 is shared in Table 3 and Table 4 for 6 year builds at 6% and 10% discount rates. Heat can also be diverted from the reactor to SOE electrolysers to improve the efficiency of hydrogen generation. LCOHt values are also listed for heat offtake at 180°C which are derived by multiplying the LCOE by reactor efficiency.

SMR and AMR costs for 2035 are shown in Table 3 and Table 4 below showing a marked reduction from that from GW scale nuclear, based on published data from the Energy Systems Catapult. The basis for this reduction is due to the anticipated saving that is unlocked from using a modular design, and the learning from deployment of prior nuclear build programmes, for example Hinkley Point C. These cost estimates are distinct from those provided for the deployed demonstrator, where capital costs of the reactor are already amortised. Note further cost reductions may be possible beyond 2035 for SMR and AMR technology. A range of discount rates is listed to demonstrate the impact of financing costs on the viability of new reactors.

It is important to note however that while heat from SMR technology is cheaper than AMR, the SMR heat is at a lower temperature. AMR heat is anticipated to provide higher hydrogen throughput SOE electrolysers, and unlocks the use of higher temperature hydrogen production processes (e.g. thermochemical hydrogen production processes).

Table 3- LCOE Values Calculated for SMR and AMR Nuclear Technology Deployed in 2035 (2023£)

Scenario	6% Discount Rate	10% Discount Rate
SMR (£/MW$_e$)	34.79	57.17
AMR (£/MW$_e$)	33.17	53.73

Table 4- LCOHt Values Calculated for SMR and AMR Nuclear Technology Deployed in 2035 (2023£)

Scenario	6% Discount Rate	10% Discount Rate
SMR (£/MW_{th})	11.48	18.87
AMR (£/MW_{th})	14.92	25.00

5.2.2. Estimates for LCOH of AMR and SMR Technologies

The LCOH for all scenarios was calculated using the methodology shown in Figure 28 aligned to prior preliminary modelling completed by NNL[47] using BEIS data[48]. LCOH values were calculated assuming the following input configurations:

- an electric only SOE input
- a split of electrical and heat inputs for the case of:
  - Reactor-diverted heat (180°C) taken from before the reactor turbine set – referred to in this text as 'costed heat'

In this calculation the cost of electricity was assumed to be constant assuming Nth of a Kind (NOAK) reactor costs at a 6% discount rate, and First-of-a-kind (FOAK) reactor costs at a demonstration phase with a 10% discount rate.

In calculating the scenarios which use an electrical and heat input, the hydrogen conversion efficiency shown in the brackets of Figure 28 was modified into an effective electrical input (calculated from Ceres provided data) which reduces the cost of conversion where heat input is present. In these cases the cost of hydrogen production technology was reduced by 17.6% (560/680) to account for the increased production rate of hydrogen and normalise it to a per MWh (or kilogram) value.

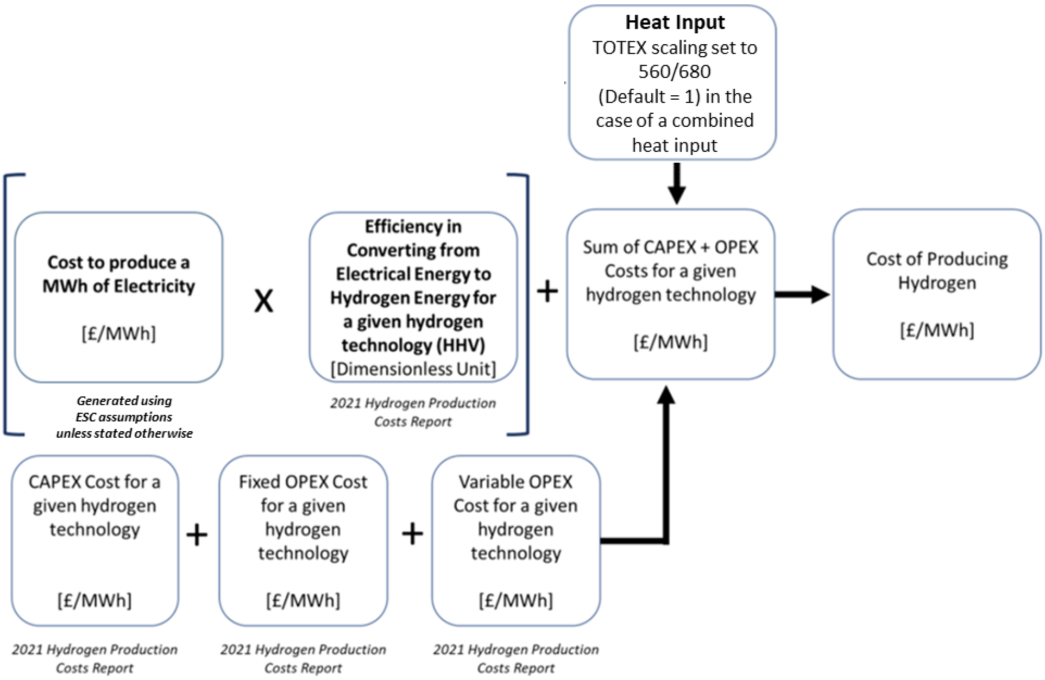


Figure 28- Methodology for calculating LCOH in Nuclear Enabled Hydrogen Production Scenarios. Note all data was inflated or deflated to 2020 values in line with the 2021 Hydrogen Production Costs Report[48]

Further detail on the methodology and assumptions for each specific case are detailed in Sections 5.2.3, and 5.2.4 for the FOAK LCOH calculation and NOAK LCOH calculations (using BEIS data).

5.2.3. Estimates for a First-of-a-kind (FOAK) Demonstrator Costing

This section presents the output of the LCOH calculation for a First-Of-A-Kind nuclear coupled SOE hydrogen production facility.

In this calculation a discount rate of 10% (to represent a FOAK costing), BEIS electrolyser cost data and Ceres electrolyser performance data were used to produce an LCOH, using the methodology outlined in Figure 28.

For this scenario an LCOH of £3.21 was calculated using the assumptions detailed in Table 5 below.

Table 5- Assumptions made in calculating FOAK deployment scenario LCOH costings

Assumption	Rationale
BEIS electrolyser cost data has been used for this calculation	BEIS Electrolyser Costs provides the most conservative assumption for the SOE technology cost in a 2035 scenario
CERES electrolyser performance data has been used for this calculation	Ceres data is the most recent hydrogen production data accessible for these calculations, and is pessimistic when compared to BEIS data.
A costed heat and electricity configuration has been employed	The demonstrator project will utilise a heat input as its source of energy
Discount Rate of 10% has been employed	This is standard (conservative) financing for nuclear deployment. The current NNL economic model has an assumed LCOE at a discount rate of 10% which has been employed.

KEY FINDING

For a FOAK demonstrator an LCOH of £3.21/kg is calculated at the point of production based on BEIS cost assumptions

5.2.4. Estimates for a Nth-of-a-kind (NOAK) Demonstrator Costing

This section presents the output of the LCOH calculations for NOAK nuclear coupled SOE hydrogen production technology. Two scenarios have been calculated for SMR and AMR technologies as follows:

- Electricity Only Input
- Electricity and Heat Input (Costed)

In this scenario BEIS electrolyser performance and cost data has been assumed and LCOE values (presented in Section 5.1.1) at a discount rate of 6% are assumed to represent NOAK technologies. The methodology and results for each scenario are outlined below, with assumptions summarised in Table 6. Values presented in this section are tabulated in Table 7 and Table 8 and presented in Figure 29 and Figure 30 for SMR and AMR technology respectively.

For both SMR and AMR technologies with costed heat input the electrical to hydrogen conversion factor was split into an electrical input component and thermal input component (which was assumed to be 25% of the electrical input).

As a thermal input is a different energy vector to an electrical vector, the electrical input was converted to a thermal input using the following Equation (2):

$$Effective\ Thermal\ Input = Thermal\ Input\ (kWth/kWh) + \frac{Electical\ Input\ (kWe/kWh)}{Effiency\ of\ Nuclear\ Reactor} \quad (2)$$

This effective thermal input was treated as an effective electrical input by dividing this value by the reactor efficiency shown in Equation (3):

$$Effective\ Electrical\ Input\ (kWe/kWh) = Effiency\ of\ Nuclear\ Reactor * Effective\ Thermal\ Input \quad (3)$$

Table 6- Assumptions made in calculating NOAK costed heat input LCOH costings

Assumption	Rationale
BEIS electrolyser cost data has been used for this calculation	BEIS electrolyser costs provides the most conservative assumption for the SOE technology cost in a 2035 scenario
BEIS electrolyser performance data has been used for this calculation	BEIS electrolyser performance data is complete to 2050, and provides a more appropriate assumption for the long-term performance than industrial predictions.
Discount Rate of 6% has been employed	Reductions in discount rate provide diminishing returns at lower values, and the value set is subject to agreement on a case-by-case basis. Given this uncertainty, a discount rate of 6% has been selected as an ansatz which could be seen in a future deployment scenario.
A 80:20 electrical to heat input has been assumed for a costed heat scenario	Engagement with Ceres has shown this is a typical split of heat for their electrolysers using a dual input
1.4% hydrogen conversion ratio performance increase between electricity only	Decrease seen in Ceres data is the best available data.
Electrolyser cost has been reduced by a factor of 560/680 to account for the boost in production per kilo when a costed heat input is provided	Engagement with Ceres has shown this ratio is within the range of likely output for an SOE electrolyser when provided 180°C heat for 20% of the input energy.

Table 7- LCOH for 6 Year SMR coupled SOE Hydrogen Production Technologies (2035 Estimates in 2023£)

Scenario for SMR Coupled SOE Technology	2035 LCOH (2023 £/kg H_2 (HHV))
Electricity Only	2.62
Electricity and Heat (Costed 180°C Heat Input)	2.56

Table 8- LCOH for 6 Year AMR coupled SOE Hydrogen Production Technologies (2035 Estimates in 2023£)

Scenario for AMR Coupled SOE Technology	2035 LCOH (2023 £/kg H_2 (HHV))
Electricity Only	2.56
Electricity and Heat (Costed 600°C Heat Input)	2.52

KEY FINDING

For an NOAK SMR deployment scenario based on BEIS cost assumptions an LCOH of £2.62/kg is calculated at the point of production. This reduces to £2.56/kg through inclusion of a 180°C (costed) heat input.

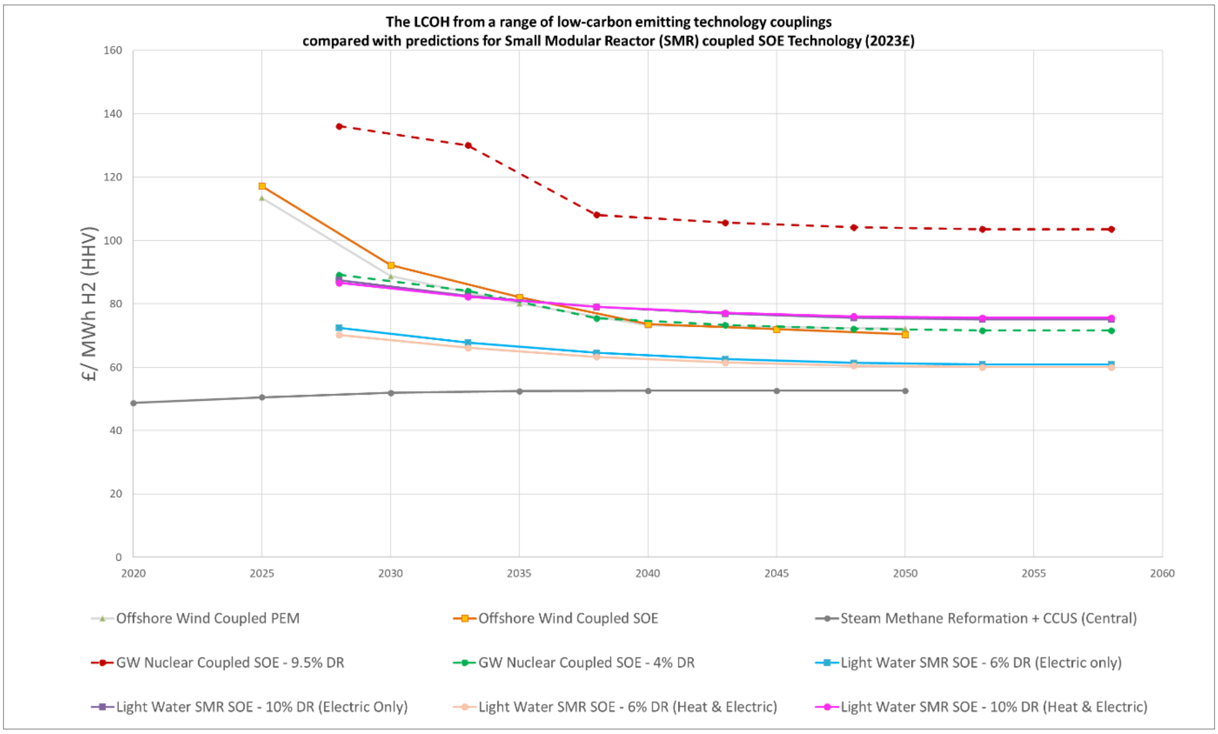


Figure 29- LCOH of SMR coupled SOE technology (BEIS assumptions) compared against a range of low-carbon technology couplings

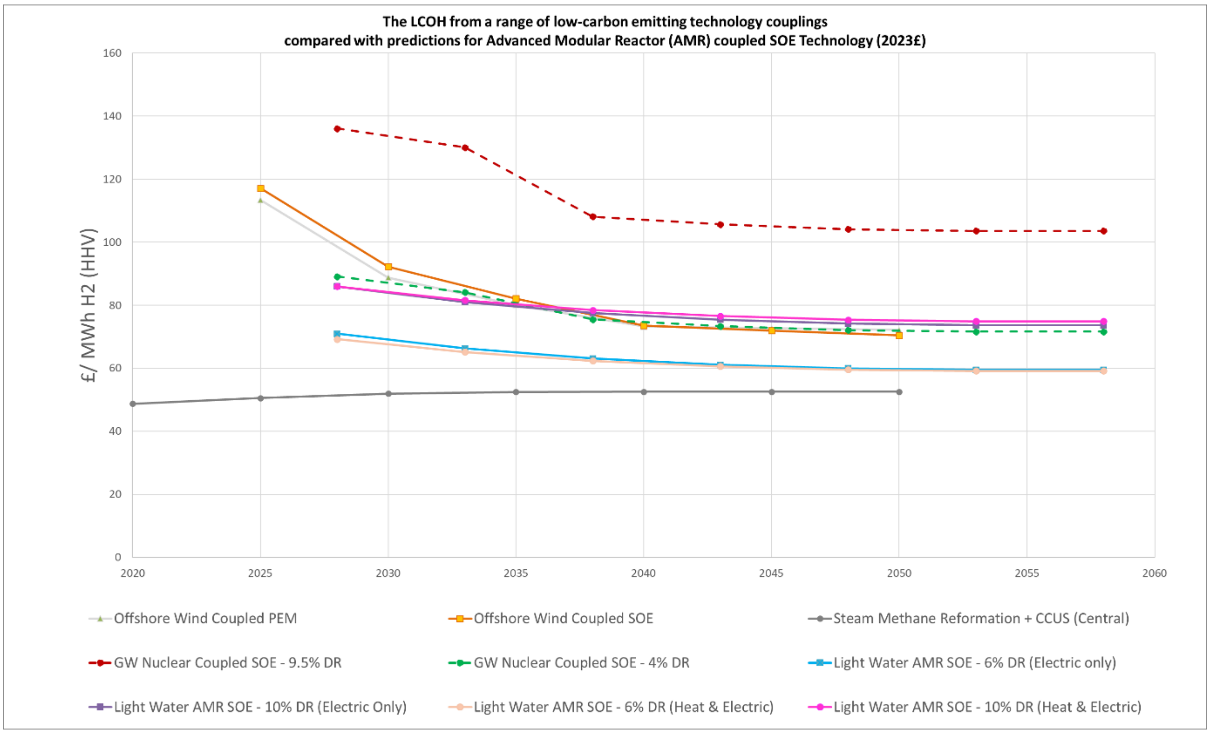


Figure 30- LCOH of AMR coupled SOE technology (BEIS assumptions) compared against a range of low-carbon technology couplings

5.2.5. Discussion

Comparison of the change in LCOH in Figure 29 and Figure 30, appear to show a similar trend of SMR and AMR coupled costings having favourable cost profiles when compared with renewable and GW scale couplings. For example it can be seen from Figure 29 and Figure 30 that SMR and AMR coupled SOE technology outperforms GW Scale nuclear coupled SOE with advanced financing and renewable coupled PEM technology for all cases with BEIS assumptions. It is important to note that the cost point of nuclear coupled SOE using BEIS assumptions could still be sufficiently low to provide a scale and opportunity-cost that enables it to be an option in a future energy system.

When comparing Figure 29 and Figure 30, AMR scenarios have been seen to slightly outperform SMR scenarios due to a more efficient assumed reactor efficiency leading to a lower LCOE, and a greater electrolyser throughput due to the higher temperature of the input steam.

6. Key Findings

This section provides a list of the key findings from within the report:

Technology and System Development

- By the early 2030s the market for nuclear technologies could be quite different from today, with multiple technologies driving cost reductions through optimised modularisation, a mature and resilient supply chain and innovation in regulatory assessment approaches that drive investor confidence and improved economics opening new markets, including hydrogen.
- HTGR / VHTR systems have the potential to support several hydrogen production methods from steam electrolysis to thermochemical methods, support industrial decarbonisation and synthetic fuel production.
- Industrial processes based on high temperatures that require modest outlet temperatures (700-850°C) have great potential for application of HTGRs in the next decade and thus there may be opportunity for direct coupling of the heat from a HTGR to industrial applications such as cement kilns with hydrogen top up to achieve the ca. 1300ºC.
- The option to deploy nuclear at scale for both domestic hydrogen production, and energy input as a feedstock for synthetic fuel production processes, could raise the ceiling and open decarbonisation pathways currently believed to be out of reach for hard to decarbonise sectors such as long-haul aviation.
- Ceres SOEC is metal supported technology operating at lower temperatures (530-630°C) than ceramic SOEC (600-900°C) offering improved robustness, more cost-effective system materials and easily recyclable stacks.
- Thermochemical hydrogen production processes are likely to be longer term options that should remain under review and be considered for large scale hydrogen production alongside AMR developments. In the meantime, innovation in the use of steam electrolysis with nuclear energy presents a nearer term option.
- Thermochemical technologies could be enabled by the rollout of steam electrolysis providing an alternative production route to achieve future cost reductions of hydrogen production.
- Site layouts that include the hydrogen production facilities off the nuclear licensed sites could reduce cost and improve maintainability compared to systems located on the licensed site.
- When considering co-locating the production and storage with end use, in this case asphalt/ cement manufacture, reflecting on the nuclear industry's experience working alongside hazardous industry such as at Hartlepool, it is understood the processes and procedures already implemented would be sufficient for hydrogen generation adjacent to Hanson and other industrial sites with the main areas for consideration being hydrogen storage and safety culture changes.

Replicability and Scalability

- By using steam directly from the nuclear plant, Ceres SOEC can produce hydrogen at high efficiency (>90% LHV), requiring ~37kWh electrical power per kg hydrogen produced.
- The long-term stability and tolerance to on/off cycling could make the Ceres SOEC technology an excellent partner to nuclear energy by enabling frequent and rapid

ramping of electrical output to the national grid to compensate for the variability of renewables.
- The anticipated ramp up hydrogen demand in the 2030s aligns well with the nuclear and hydrogen production technology developments and roll out.
- The total energy demand for hydrogen by Hanson of 624 GWh would equate to approximately 260 MW_{th} of nuclear capacity. This is approximately one quarter of the output from a RR-SMR or 26 U-Battery systems. Therefore, using nuclear energy, one RR-SMR operating constantly producing hydrogen could provide all of Hanson's hydrogen energy requirements for decarbonisation four times over.
- The Energy Technologies Institute study indicates a potential nuclear capacity across the UK of 83.8 GW_e, this includes the use of development next to existing nuclear sites through to the use of brownfield and greenfield sites. While significant work would be required to enable all of these sites, this study indicates siting does not need to be a constraint to capacity.
- In the near term it is likely that the supply of nuclear enabled hydrogen to Hanson sites will be reliant on hydrogen transport and distribution networks. In the longer term, the potential for co-location, particularly considering future technologies with more flexible siting requirements should remain under review.
- The distribution of hydrogen to Hanson sites through a converted hydrogen gas distribution network presents a potential option subject to economic and location considerations.
- Most of the national gas grid in the UK is already compatible with hydrogen and there are no showstoppers for injection of nuclear derived hydrogen into the gas grid. The area requiring development is storage, due to the larger volumes of hydrogen required compared to natural gas.
- The UK operates the world's oldest salt cavern hydrogen storage facility in Teesside which opened in 1972. Salt cavern storage is the most developed form of hydrogen storage with a potential for UK salt cavern hydrogen storage capacity of 2,150 TWh
- The total land area required to replace the UKs current oil consumption with hydrogen generated from nuclear energy is ~55km^2, which equates to approximately 1.6 times the land area of the UK's current oil refineries.

Future Hydrogen Economics

- AMR and SMR technologies have potential for decreases in LCOH via reduction of CAPEX and OPEX costs and because of their cogeneration capacity. High-capacity factors provide a reliable power source suitable for continuous operation of hard-to-abate industries.
- For a FOAK demonstrator an LCOH of £3.21/kg is calculated at the point of production based on BEIS cost assumptions
- For an NOAK SMR deployment scenario based on BEIS cost assumptions an LCOH of £2.62/kg is calculated at the point of production. This reduces to £2.56/kg through inclusion of a 180°C (costed) heat input.

7. Conclusions and Recommendations

7.1. Conclusions

The development of nuclear reactor technology over the coming decade may open new markets for nuclear energy including enabling hydrogen production to support industrial decarbonisation and synthetic fuel production, facilitating decarbonisation pathways for hard to decarbonise sectors such as long-haul aviation. There may also be opportunity for direct coupling of the heat from AMRs to industrial applications such as cement kilns with hydrogen top up to achieve the ca. 1300°C required.

Evidence provided within this report shows that both the potential siting opportunities and economics of nuclear derived hydrogen produced through steam electrolysis, could be cost competitive with other solutions supporting the case that nuclear is a viable option for hydrogen production in the UK. This is further backed up by the timelines for nuclear development and the anticipated continued ramp up of hydrogen demand in the 2030s.

While in the longer term the potential for co-location, especially with AMRs, exists, in the short term it is likely that the supply of hydrogen will be reliant on hydrogen transport and distribution networks. The distribution of hydrogen through the national gas network in the UK, the majority of which is already compatible with hydrogen, could offer a significant opportunity subject to economic and location considerations. There is also significant experience and innovation in hydrogen storage, with the UK operating the world's oldest salt cavern hydrogen storage facility in Teesside which opened in 1972. Salt cavern storage is the most developed form of hydrogen storage with a potential for UK salt cavern hydrogen storage capacity of 2,150 TWh.

The developing technologies of SMRs and AMRs also offer the potential for decreases in the LCOH, with a further decrease in LCOH possible by adopting novel financing models which are already used on other large UK infrastructure projects. The high-capacity factor of nuclear reactors also enables a smaller capacity of hydrogen production technology to produce the same quantity of hydrogen as intermittent renewable technologies.

It is estimated for the LCOH using SOEC technology coupled with a 300 MW_e SMR built under the RAB model (with an assumed 6% Discount Rate) hydrogen could be produced at a levelised cost of £2.62/kg by 2035 and with the potential technical opportunity of using direct heat at 180°C, and economic opportunity of capturing and utilising the oxygen by-product this could come down further.

7.2. Recommendations

- Use the learning from the Hydrogen4Hanson project to deliver a stronger evidence base for the role of nuclear enabled hydrogen in a future energy system.
- Further invest in development and demonstration of new nuclear reactor technologies (SMR, AMR, Fusion), hydrogen production methods (steam electrolysis and thermochemical) and coupling technologies to enable nuclear enabled hydrogen production to become a proven viable production technique.
- Continue to collaborate across industries and sectors to understand how hydrogen will be transported and stored in a future energy system.
- Refine understanding on co-location considerations both nuclear plant and hydrogen generation and also hydrogen storage and end use.
- Further consider the oxygen produced as a by-product of hydrogen production including the economic value of capturing and utilising within industry.
- Investigate the feasibility of Hanson connecting more of its sites to the gas network and the use for hydrogen supply.
- Refine understanding of the cost and performance (including the lifetime) of steam electrolysis cells and coupling of technology to nuclear reactors with 50+ year operation.
- Gain an understanding on how demand of cement and asphalt varies throughout the year and geographically and how this may impact the hydrogen production and storage requirements.

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Annex 2 – Future Development of End Use Applications

Future Industrial & Other H_2 developments

Commercialisation prospects of a future industrial plant utilising hydrogen

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Introduction

Transition to net zero emissions industry is critical to reach net zero by 2050 in the UK and contribute to slowing and reversing global average temperature rise below 1.5 degrees Celsius. While great progress is being made in decarbonising mobility and electricity in the UK, other sectors such as asphalt or cement require support to transition to low-carbon operations cost effectively and without negative impacts on business growth. A combined public-private sector approach would accelerate solutions to existing challenges; however, the necessary changes will need to be supported by engineering developments, regulatory framework, and investments. Innovative zero-carbon technologies will play a central role in industry; however, they must be realistic, achievable, and practical.

Objectives and Scope

This chapter will address hydrogen use in cement and asphalt sectors and future commercialisation of nuclear-derived hydrogen at dispersed sites. It will also investigate related industries where hydrogen can be utilised as an economically and technically viable solution.

The scope of work will cover the full spectrum of future industrial hydrogen developments, the main areas of focus are:

- Costs for future commercial plant at dispersed sites
- Scalability & Replicability
- Benefits of solution and challenges
- Carbon emissions savings potential
- How solution will *continue to develop post demonstrator inc. cross sector potential carbon savings*
- Social Value impact

UK Asphalt and Cement Market

Market size

Asphalt

Asphalt is a versatile bituminous material that is used for variety of surface applications: road construction and maintenance, footpaths, sport and recreation areas and civil engineering projects. The construction material is produced by combining asphalt binder (or bitumen) and a mixture of aggregates at elevated temperatures: 135-165ºC. There are over 280 asphalt plants across Great Britain, producing c.22.7m tonnes of asphalt in 2019 (27.4m tonnes in the UK). The production of asphalt remained steady 2015-2019 post a decline from 2004 to 2012, especially impacted by economic crisis in 2008. The sector experienced a sharp fall in output due to COVID-19 pandemic in 2020 following industry shut down, but has rebounded strongly, hitting c.28m tonnes in 2021, similar to 2004 levels (1).

Figure 2 - MPA asphalt sales in the UK, 2004-19 (Million tonnes)

Figure 1 MPA Asphalt sales by region (Million tonnes)

Cement

Currently, concrete is the second most consumed substance globally behind water. The material enables the construction of small to mega scale infrastructure projects - homes, schools, hospitals, transport infrastructure. Since it is a ubiquitous substance, there is no wonder why it generated around £329m Gross Value Added (GVA) (2). The fundamental ingredient in concrete is cement, which is regarded as a binder with other substances such as gravel and sand. The UK cement industry has an annual turnover of around £800 million and contributes c.4.2MtCO2e p.a (c. 6% of total UK industrial emissions). The cement industry can significantly contribute to reducing overall carbon emissions and provides the opportunity to develop clean energy technologies and fuels such as hydrogen, biofuels and Carbon Capture and Storage (CCS).

Figure 3 - MPA cementitious sales in UK, 2002-19 (Million tonnes)

In the UK there are 7 cement manufacturers, which are represented by the Mineral Products Association (MPA) Cement: Hanson Cement, Breedon Cement, CEMCOR, CEMEX, Lafarge Cement, Tarmac and Imerys. These manufacturers have capacity to supply approx. 12 million tonnes of cement and satisfy 87% of the market demand and turnover at around £1bn. Adding to those 25.4 million tonnes of asphalt sales in 2019 within construction and overall £20bn turnover, it makes the two huge sectors both attractive for further investments and developments.

Market trends

Asphalt

As global climatic patterns become less predictable, demand for sustainable construction material is accelerating. The main market trends associated with it are listed below:

- Warm mix asphalt (WMA) - a reduced temperature asphalt production process that offers 15% carbon savings and higher efficiency. WMA can reduce emissions associated with asphalt production up to 15% (3).
- UK asphalt producers are planning to default to WMA for all lower layer materials.
- Recycled asphalt demand from 2016 to 2020 increased by 2.5% and is expecting further growth.
- ALARM 2022 reports that the backlog of carriageways repairs will take nearly a decade to complete and will require a budget of £12.64bn (4)
- In England, government announced £27bn programme on road investment which could mean that asphalt manufacturers will need to increase their annual output

Cement

Historically, import of cement to the UK did not exceed 13% until 2009. Since then, the imports steadily increased and now, according to MPA Cement, are above 20%. The lack of decarbonisation action in this industry might accelerate this trend. The imports are set to increase as green concrete becomes front of mind for customers, in this case concrete manufacturers. As such, lack of actions and available solutions among the UK concrete and cement producers might have meaningful negative impact on the local industry a whole. The MPA Cement Director of Energy and Climate Change stated that cement manufacturers are looking for solutions that Bay Hydrogen Hub technology may offer.

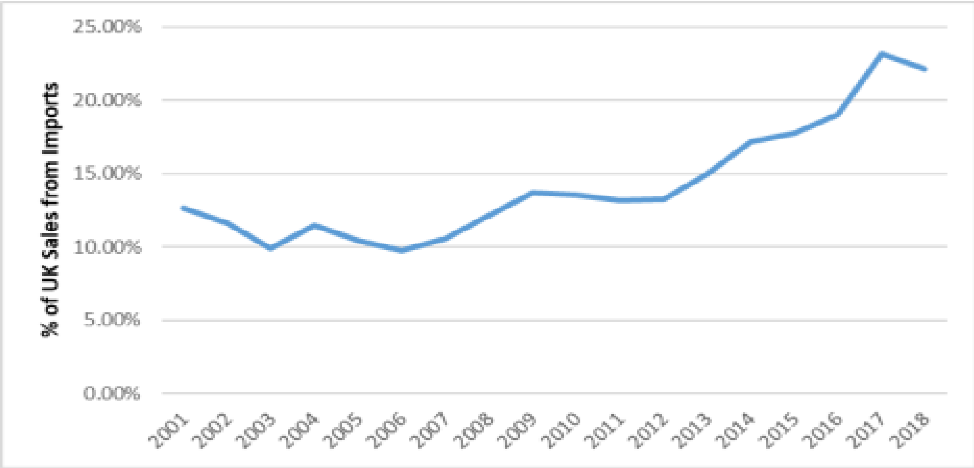

Figure 4 - Proportion of UK Sales from Imported Cement 2001-2018 (5)

Growth of global population and urbanisation creates significant demand in building infrastructure, which requires materials. There is a strong sustainability focus within the sector that will allow production of low-carbon construction materials and, possibly, cost reductions. It is evident that UK construction companies will be looking to leverage more environmentally friendly alternatives with respect to deployment of cement and asphalt.

Asphalt and Cement Emissions

Asphalt and Cement production are considered foundation industries providing essential materials for the economy, with products used widely in the construction sector. Since both manufacturing processes are energy intensive, there are great efforts being made to reduce the carbon footprint.

Asphalt

Asphalt production requires heating of bitumen to temperatures over 100ºC as it remains at solid state at ambient temperatures. Additionally, process requires aggregates with low moisture content hence it needs to be dried and heated before mixing it with bitumen. These two processes are the main energy consumers where fossil fuels are involved. According to some studies production of Hot-Mix Asphalt (HMA) consumes 275 MJ/t (c.77kWh/t) of energy and releases 22-25 kg of CO_2/t of asphalt.

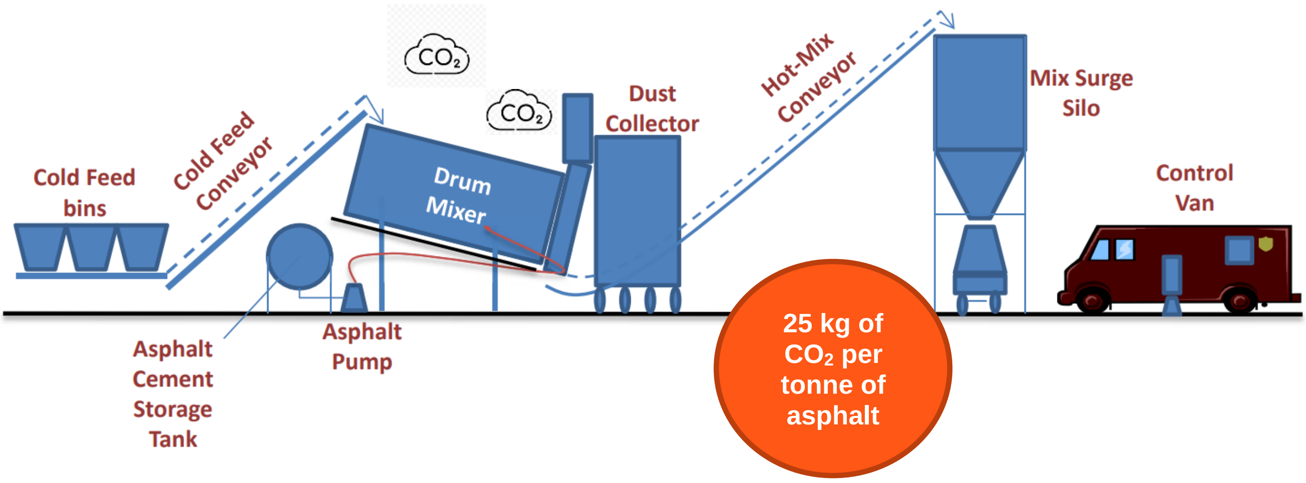

Figure 5 Asphalt production process (6)

Source of CO_2 emissions in asphalt production can be classified as follows:

- Production emissions from burners (largest emission source), on-site mobile plants and transport emissions from delivering to the customers

- Emissions from electricity consumption
- Emissions from purchased goods and services

Cement

Between 1990 and 2018 emissions in cement sector were reduced by ~50%. Yet the industry still significantly contributes to greenhouse gas emissions. It has been estimated that in the UK in the period between 2009 and 2018 cement manufacturers released approximately 6.5 Mt of CO_2 annually. (7). That shows that over the past two decades industry struggled to further cut emissions, mostly due to the nature of the production process, Figure 6When considering cement production, two sources of emissions dominate: process emissions and combustion emissions. Cement manufacturing involves clinker production, and this process step is responsible for most of the CO_2 release. This is due to limestone converting to lime, and naturally occurring by-product of this chemical reaction is carbon dioxide. Combustion emissions arise due to burning fossil fuels to reach high temperatures required in the kilns. Process emissions cannot be avoided completely as they are a result of a chemical reactions that take place during the production process. However, steps can be taken to reduce the amount of process emissions by implementing more efficient production processes, using alternative raw materials, or by capturing and storing emissions. Reducing emissions from combustion is generally considered more straightforward task than reducing process emissions since alternative fuels such as hydrogen or biomass can be introduced, and they produce lower lifecycle emissions than traditionally used fossil fuels.

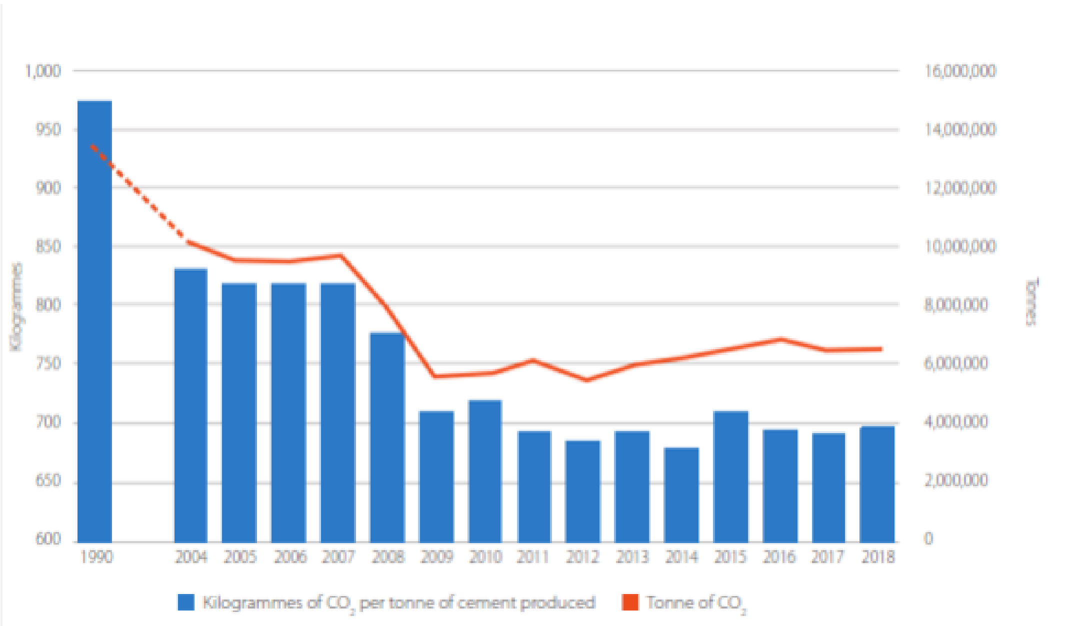

Figure 6 CO2 emissions from UK cement production plants

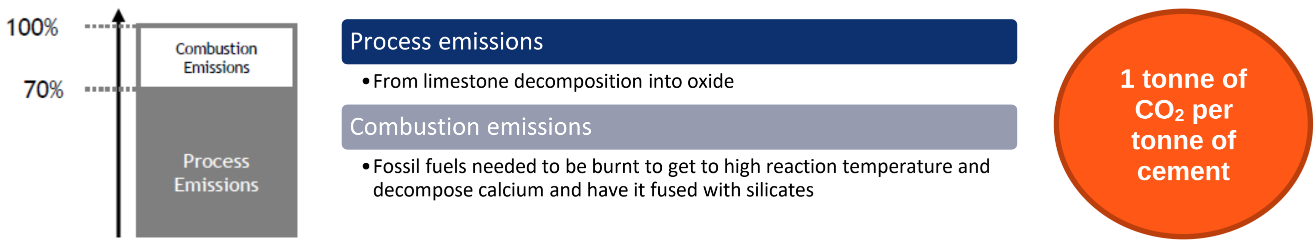

Figure 7 - Emissions per tonne of cement

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Emissions costs

Cost of carbon is a growing concern in the industry. All the carbon-intensive sectors will face a real challenge of direct and indirect climate change policy costs. However, cement manufacturers will be particularly impacted because of the lack of compensation for indirect CO_2 costs unlike steel or paper industry (8). According to the MPA, all costs related to climate change mitigation and energy policies could double in the next 5 years. Separately, the ongoing energy crisis driven high prices, price volatility, and supply shortages have already had a huge impact on production costs. Climate and energy policy costs will incentivise industry to find low-carbon solutions, however this must be coupled with support and positive incentives to develop and invest in low carbon technology and fuels, ensuring that UK production remains competitive domestically and internationally.

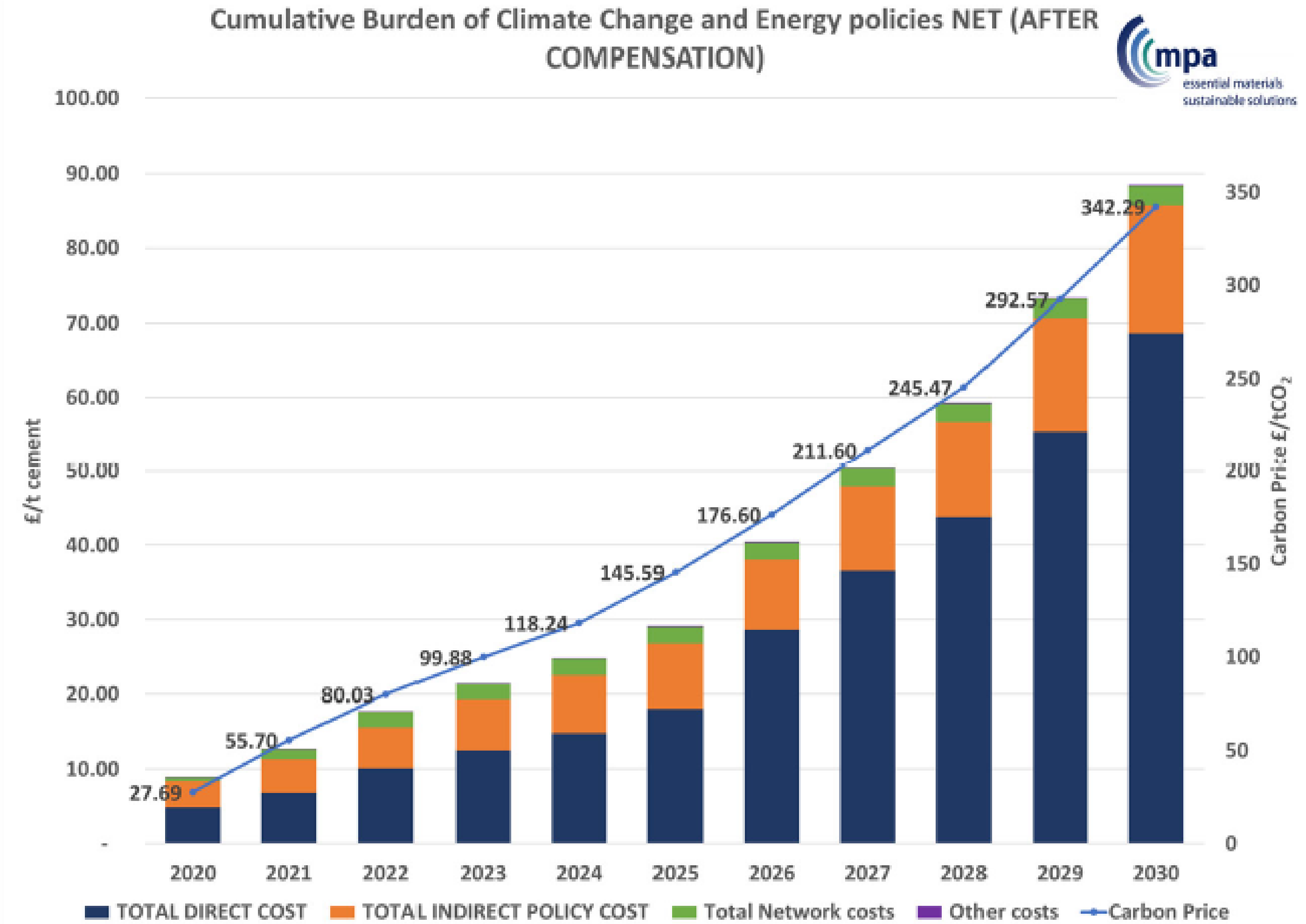

Figure 8 - MPA Climate and Energy Policy cost estimates per tonne of cement produced - after industry compensation (Greenbook carbon prices)

Currently used energy sources

Asphalt

Thermal energy for producing HMA is required for the process of heating a binder and drying aggregates. Drying burners are the largest emissions source at an asphalt plant and usually designed to operate on almost any type of fossil fuel. Currently, natural gas, gasoil (red diesel) and recycled oil are the primary source of energy used. The average power process-related consumption of an asphalt plant is around 80-90 kWh per tonne of asphalt, which is significant given the UK volumes of asphalt produced every year and emissions that can be reduced when implementing alternative fuels (9) (10). Non-fossil fuels can be used in the production process, it could be biomass, waste oil or hydrogen. The use of alternative fuels will not only help reducing emissions, but also decrease the industry reliance on fossil fuels.

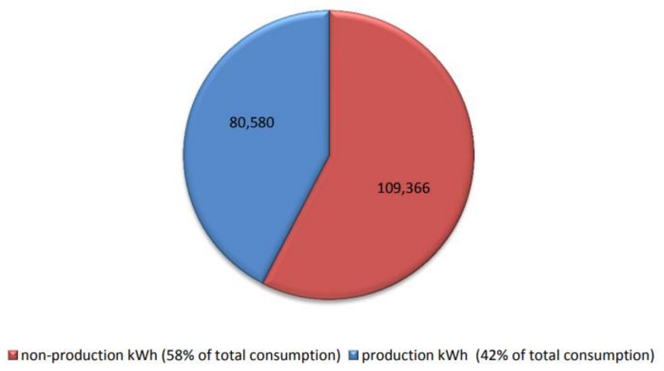

Figure 9 Energy consumption of asphalt production

Additionally, many businesses have been impacted by the relatively recent changes in legislations related to the usage of red diesel (11). It was announced that many sectors, including construction, will lose their entitlement to use rebated diesel from April 2022. This change in legislation has posed a challenge for many businesses, but also incentivised these rebated fuel users to seek low-carbon alternatives fuels.

Cement

As discussed in the previous section in this chapter, manufacturing of cement is an energy intensive process as it requires temperatures of around 1400ºC for clinkerisation. Fossil fuels like coal and natural gas are primary fuels used in the cement kilns to reach high temperatures required. All those fuels contribute to climate change, but they are currently the most affordable and reliable. Cement manufacturers are actively seeking alternative fuels; however, the majority in the UK are still dependent on coal.

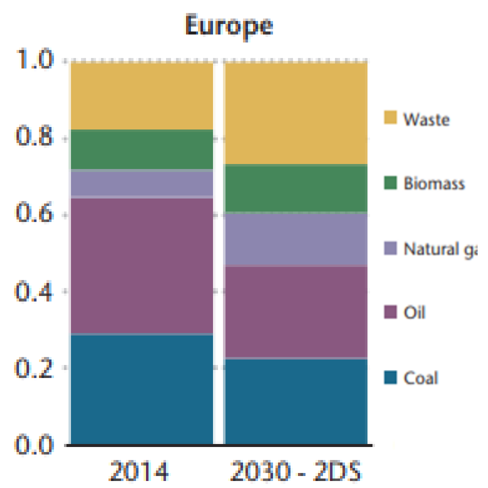

Figure 10 Thermal energy mix in cement in the 2ºC scenario (2DS) (12)

Waste and biomass are widely used in the cement industry, which can be a cost effective and low emissions energy source, depending on sustainability of production. However, they pose numerous challenges concerning their varying quality (moisture and N_2 content, particle size distribution), and availability of the supply at the scale required. The BEIS funded *State of the art fuel mix for UK cement production to test the path for 'Net Zero': a technical, environmental and safety demonstration* report flags a barrier of a lack of biomass abundancy of biowaste. It was stated that use of hydrogen was highly successful and further hydrogen development works would depend on UK plans for increasing hydrogen availability.

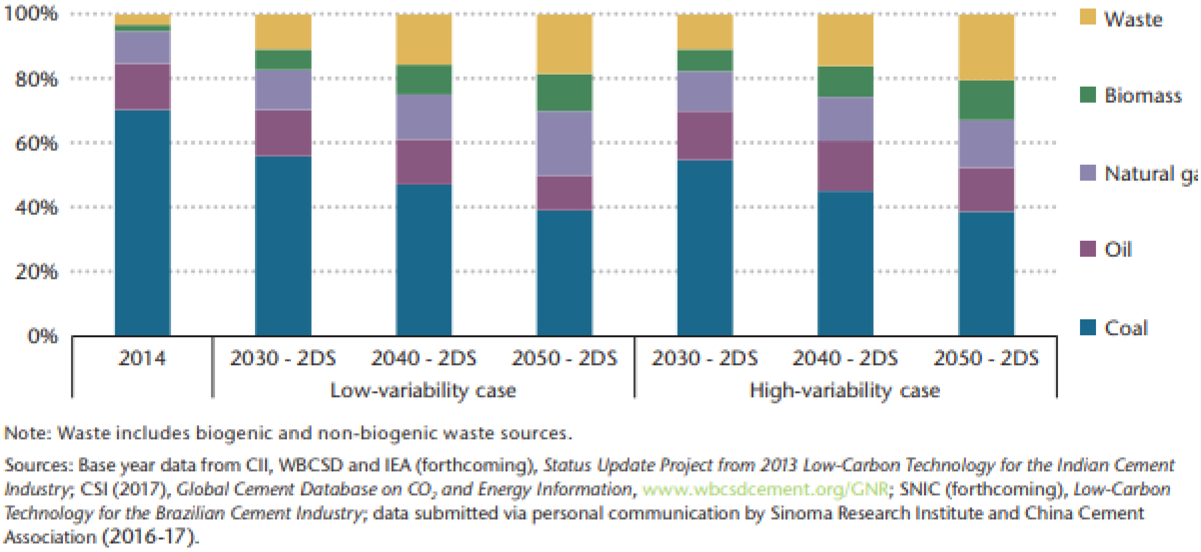

Figure 11 Global thermal energy mix in cement in 2ºC scenario (12)

Pathways to decarbonise cement and asphalt

It is crucial to understand the relevant net zero technologies and implement necessary changes. While the asphalt sector is exploring GTL (gas-to-liquids) as an alternative to diesel, it is still not the most sustainable source of energy that can be used. Fuel switching holds considerable promise in helping cement and asphalt sectors meet targets on the MPA net zero roadmap. It has been estimated that by 2050, 16% CO2 emission reduction in the cement industry can be achieved through fuel switching technologies. Asphalt plants fuel switching would bring additional emission savings, especially when looking at the scale of this sector. There are several pathways to decarbonisation:

- Low carbon binders – asphalt is typically made from mixture of aggregates (such as crushed stone and/or sand) and a binder (such as bitumen). The use of low-carbon binders, such as those made from bio-oils or recycled plastics can significantly reduce carbon footprint of asphalt.
- Alternative fuels – low or zero-value materials such as waste oil, plastics, shredded residues and waste tyres can be used in the cement production process, however these materials bring several challenges due to variation of chemical composition which impact clinker's quality as they interfere with the chemical reaction. Switching to alternative energy sources such as hydrogen or electricity could reduce carbon emissions associated with the use of fossil fuels in both asphalt and cement sectors.
- Waste and biomass accounts for 43% of fuel used in the cement production plants in the UK (14). Using waste as an industrial fuel has a strong policy implication: controlled waste collection, treatment and processing waste into heat is critical for high standards of quality control to avoid other hazardous pollutants.

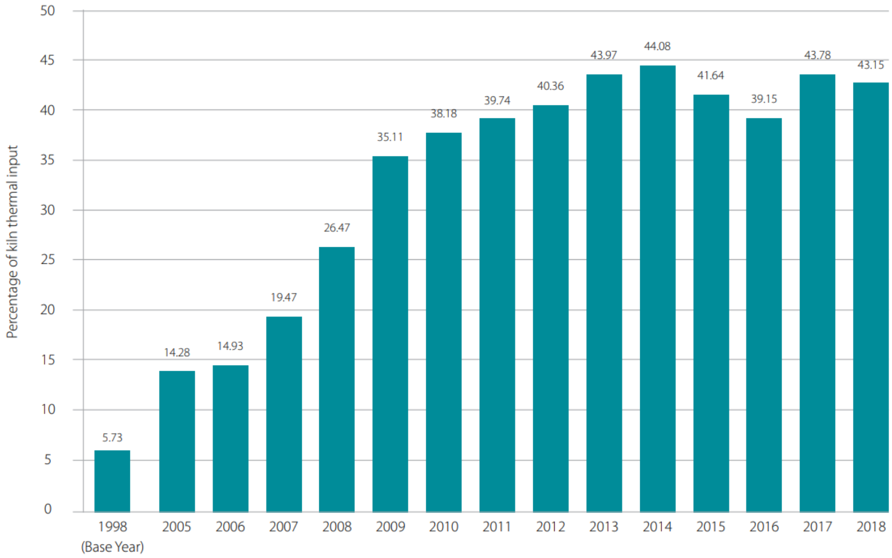

Figure 12 Waste derived fuel use in 1998 and from 2005-2018

- Carbon capture and utilisation – these technologies can be used to capture carbon emissions from production of asphalt and convert them into useful products such as fuels or chemicals. It is worth noting that the emissions from cement plants have two sources: CO2 as a by-product of chemical reaction and emissions from burning fossil fuels, which means that to lower emission within this sector, different technologies would have to be implemented. Fuels switching in cement plants partly solves the overall emission problem, and it is likely to be coupled with Carbon Capture and Storage/Utilisation technology to allow CCUS plants to be smaller or even provide the opportunity for cement plants to be carbon negative (capturing biogenic carbon from biomass/waste fuels).
- Recycling and reuse – it can significantly reduce the need for virgin materials and therefore reduce carbon emissions.
- Use of Warm Mix Asphalt (WMA) - currently WMA is gaining a lot of interest from the industry; this process requires temperatures between 100-120ºC vs. standard production process of HMA of approximately 170ºC (15). Studies present different CO_2 savings when switching to WMA, however it can be estimated that 15-40% CO_2 reduction can be achieved. Apart from industry efforts on lowering the process temperatures, there is also an opportunity to fuel switching since intensive drying of aggregates is a key plant role. Coupling production method of WMA with fuel switching to hydrogen can greatly contribute to both energy savings and carbon emissions reduction.

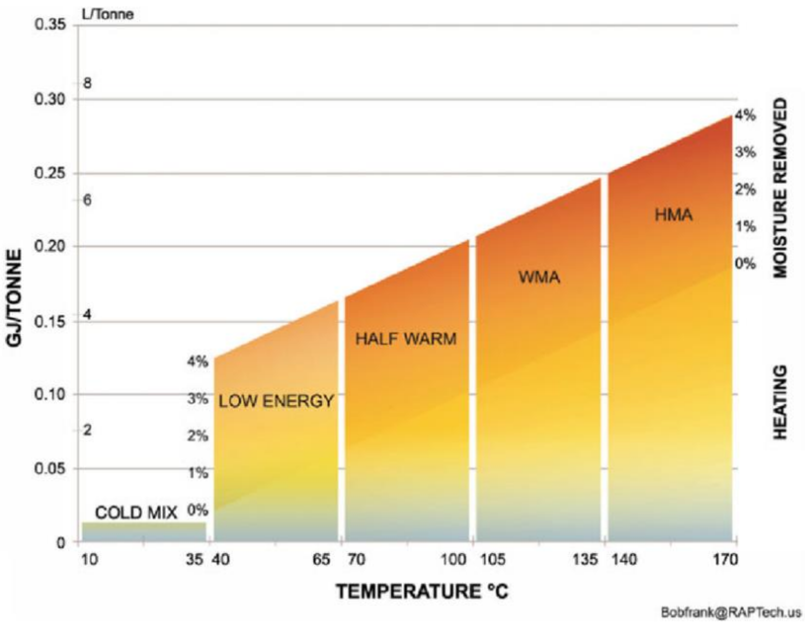

Figure 13 - Asphalt plant temperature range and input types

There are a variety of different ways to reduce carbon footprint in industry, however manufacturers must be mindful that some of the technologies might affect properties (such as product durability) or product lifecycle - that might mask additional carbon costs. Reuse-recycle-reduce is a motto used by environmentalist to reduce waste and minimise consumption, and it should be also incorporated and promoted in foundation industries to help facilitate the green, circular economy.

Additionally, sustainable technologies need to ensure security of supply, considering the industry risks exposed during and post the Covid-19 pandemic.

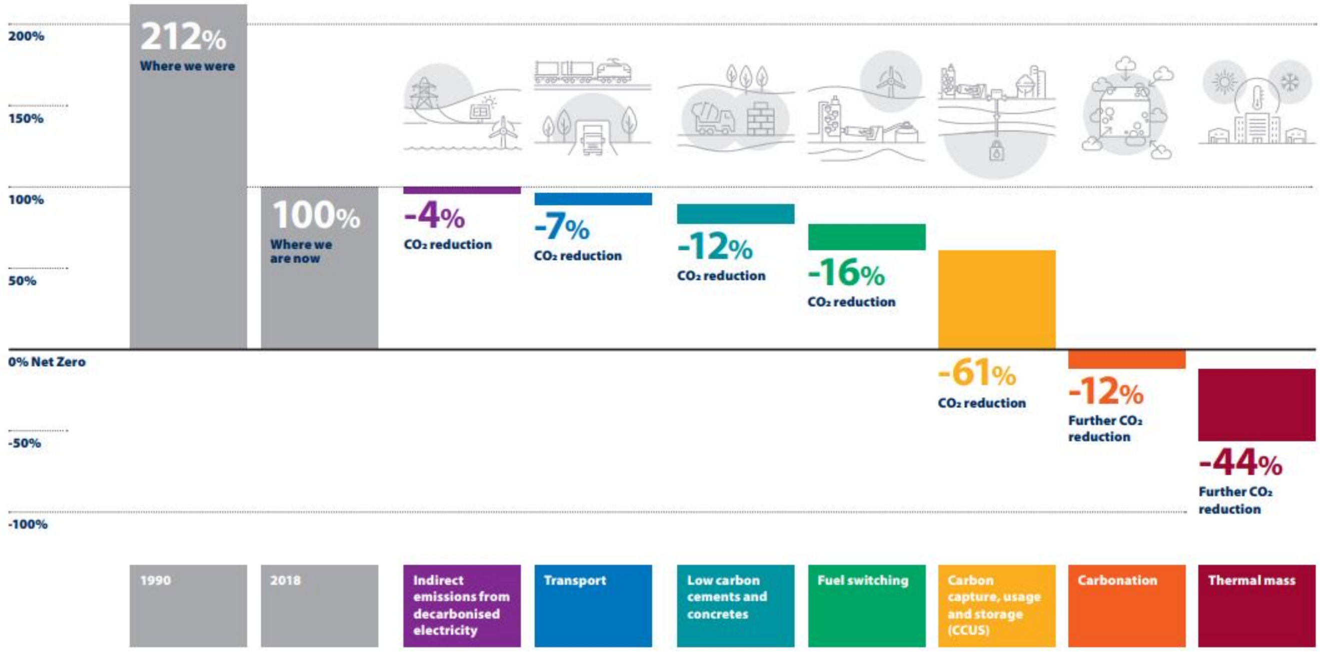

Figure 14 MPA Cement roadmap towards Net Zero (2)Adaptability of H2 in cement and asphalt industries

The implementation of hydrogen-based technologies at scale at dispersed sites requires hydrogen production at scale, hydrogen transportation developments and upskilling existing workers.

Safety aspects

When implementing hydrogen as a fuel in a manufacturing site, several safety aspects must be considered:

- Flammability – H_2 is a highly flammable gas and special precautions must be taken to prevent fires and explosions. This would mean that manufacturing sites would need to have a dedicated and appropriate storage, ventilation systems and safety handling training incorporated to prevent the build-up of hydrogen gas in the manufacturing site.
- Leak detection – hydrogen can be difficult to detect, so proper leak detection systems must be in place on sites where this gas is implemented.
- Training – existing would need to regularly undergo training on safe handling and storage of hydrogen. Additionally, appropriate safety measures would need to be determined.
- Maintenance – regular maintenance of hydrogen related systems, equipment and infrastructure must be performed to ensure proper functioning and prevent accidents.

Overall, hydrogen is a clean energy alternative, however it requires a thorough analysis of the risk and safety measures to be taken when using it in manufacturing.

Technology availability and technical limitations

Hanson' recent hydrogen trial at a cement works overcame equipment challenges and showed that providing hydrogen to the primary kiln was technically possible. Hydrogen can be delivered to the kilns via a series of pressure reducing skids, pipework and a customised lance inserted into the main kiln burner. Alternatively, hydrogen blended with natural gas in 30% to 70% ratio could be used in many asphalt production facilities with only minor modifications to the existing technology. A variety of fuels are already in use at cement kilns. showcasing how flexible these systems are, and there is likely no major equipment refurbishment required which makes the solution competitive and cost-effective.

In contrast, the Asphalt industry has not demonstrated trials with hydrogen. Understanding the feasibility of this, and its future potential, is one of the primary objectives of the Bay Hydrogen Hub – Hydrogen4Hanson study.

It is important to understand that development of the technologies based on hydrogen relies on hydrogen availability. To transition industry into sustainable fuels, the hydrogen needs to be produced using low-carbon energy, such as nuclear and renewables. The availability of low-carbon hydrogen is currently very limited on the market and remains a barrier to hydrogen fuel switching.

Hydrogen transportation

Hydrogen transport and storage is critical to enable industry switching. Possible infrastructure includes pipelines (new or repurposing existing), liquification plants, storage facilities and compressors and trucks. Growth in hydrogen demand driven by UK government ambition for 10GW production capacity of low carbon hydrogen by 2030 emphasises the infrastructure necessity.

Hydrogen transportation is a critical contributor to overall cost and emissions, and a choice of its delivery mode depends on geographical location and market characteristics. While pipelines are considered to be the most cost-effective in the long term for large quantities of continuous supply, trucks offer high flexibility, scalability and similar cost magnitude. It is especially important in the early stages of hydrogen roll out when demand and regulatory frameworks are nascent. Flexibility is also vital for the industrial sites that are isolated and do not have pipeline connection, which is a case for large number of cement and asphalt sites. Trucks may also be the only solution for multiple dispersed sites given high pipeline connection costs apportioned to few sites.

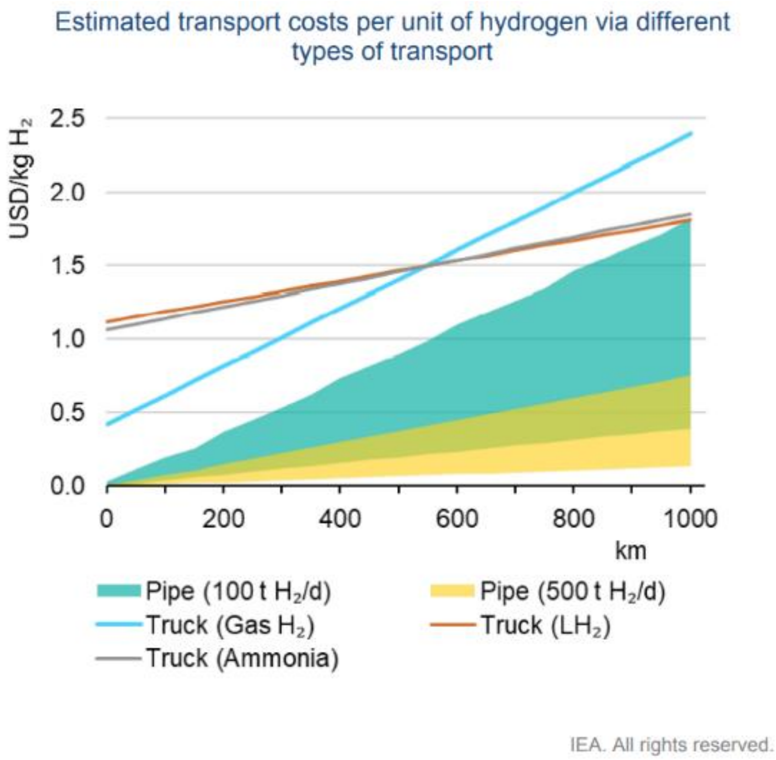

Figure 15 - IEA Assessment of H2 transport costs (16)

Pipeline networks will be vital for a future hydrogen economy, but new pipelines are capital-intensive and have high upfront investment cost. Additionally, it takes up to 10 years to build them. Existing natural gas networks could be repurposed for hydrogen service - National Grid committed to invest over £1bn in Project Union on repurposing 25% of current gas transmission pipelines, the project focuses on linking two industrial clusters – Teesside and Humberside. However, majority of asphalt and cement plants are remote from industrial clusters, hence a workable road transportation solution will be essential to catalyse hydrogen industrial expansion.

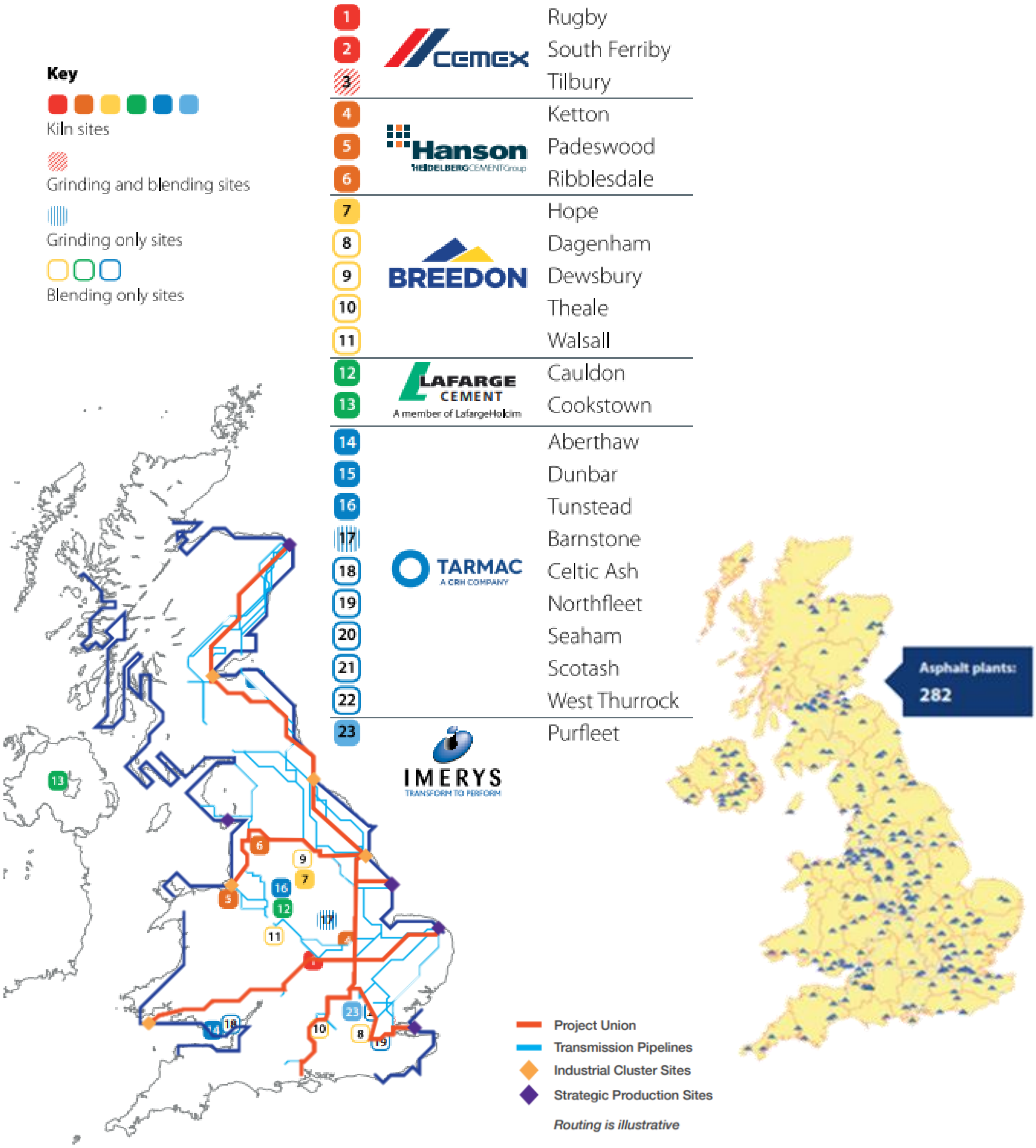

Figure 16 - Map of Project Union overlaid with Cement sites compared to asphalt site locations (National Grid, MPA)

Case studies from around the world – use of hydrogen in industry

Hanson

Hanson has conducted a feasibility study that concluded that emissions from cement production can be reduced by using a combination of 70% biomass, 20% hydrogen and 10% plasma energy. It was followed by a demonstration trial using biomass and hydrogen with the aim to run cement and lime kilns with zero-carbon fuel and reduce emissions. The study estimated that if the approach was extended across the UK, cement industry would save approximately 2 million tonnes of CO2 annually.

The trial performed in Ribblesdale has proven that hydrogen can be fired in the kiln and has the potential to meet all the technical requirements […]. However, some questions related to carbon load, health and safety at the plant and adequate flame characteristics still remain uncertain with the scale up of the technology.

Cemex

In early 2020, Cemex announced a long-term programme that aims at lowering CO2 emissions by 35% of its cementitious products. The company is considering fuel switching to hydrogen.

LafargeHolcim

This cement producer is introducing several green projects to reduce carbon dioxide emissions. One of the projects in Germany involve production of e-fuels by using captured CO2 and electrolytic hydrogen.

Carmeuse

Belgian producer of lime and limestone decided to produce e-methane on industrial scale by combining hydrogen with captured CO2. Hydrogen is being produced through water electrolysis (75MW electrolyser), while CO2 is sourced from the lime kiln. The company is planning to start supplying e-methane for transport and industrial use by 2025.

Future commercialisation

Fuel switching cost impact

Asphalt

The energy demand for Asphalt is currently provided by Processed Fuel Oil (PFO) and full conversion to hydrogen is being considered for future commercialisation. As stated in WP4 (Industrial End-Use of Nuclear Generated Hydrogen, Annex C), the minimum amount of PFO (Processed Fuel Oil, currently used fuel in asphalt production) to produce 1 tonne of asphalt is 7 kg. Knowing the calorific value of PFO is 39.8 [MJ/kg], it was calculated that minimum 77.48 kWh of energy is consumed to produce 1 tonne of product. It is important to emphasise that the fuel use in the asphalt burner is not constant, however an estimate of energy consumption had to be implemented to simplify further calculations of equivalent of energy required from other fuels: natural gas and hydrogen.

Hydrogen Cost

Water electrolysis using Solid Oxide Electrolyser (SOE) coupled with nuclear provides an attractive proposition of producing hydrogen. Levelised Cost of Hydrogen (LCOH) could be as low as 66.5 - 68 £/MWh $_{H2HHV}$ by 2035 according to the model presented in this report and estimations in Work Package 5. Graphs in this section show the impact on fuel cost for one tonne of asphalt and when switching to hydrogen is forecast to become cost competitive with existing fuels.

LCOH, Central case (BEIS)		
Year	£/MWh H_2 (HHV) (10 MW system)	£/tonne of asphalt (10 MW system)
2020	168	13.02
2025	153	11.85
2030	141	10.92
2035	135	10.46
2040	131	10.15
2045	129	9.99
2050	127	9.84

Table 1 BEIS SOE hydrogen production cost, Bay Hydrogen Hub solution

LCOH* (Bay Hydrogen Hub)		
Year	£/MWh (HHV)	£/tonne asphalt
2022 (1MW system)	423	32.77
2035 (100 MW system)	68	5.27

Table 2 SOE hydrogen production cost 2021, BEIS and cost of hydrogen (17)

Both Tables 2 and 3 capture LCOH at point of production without consideration of compression and distribution costs, however costs differ not only because of the technology efficiency and other variables, but also because of the scale of the electrolysers assumed.

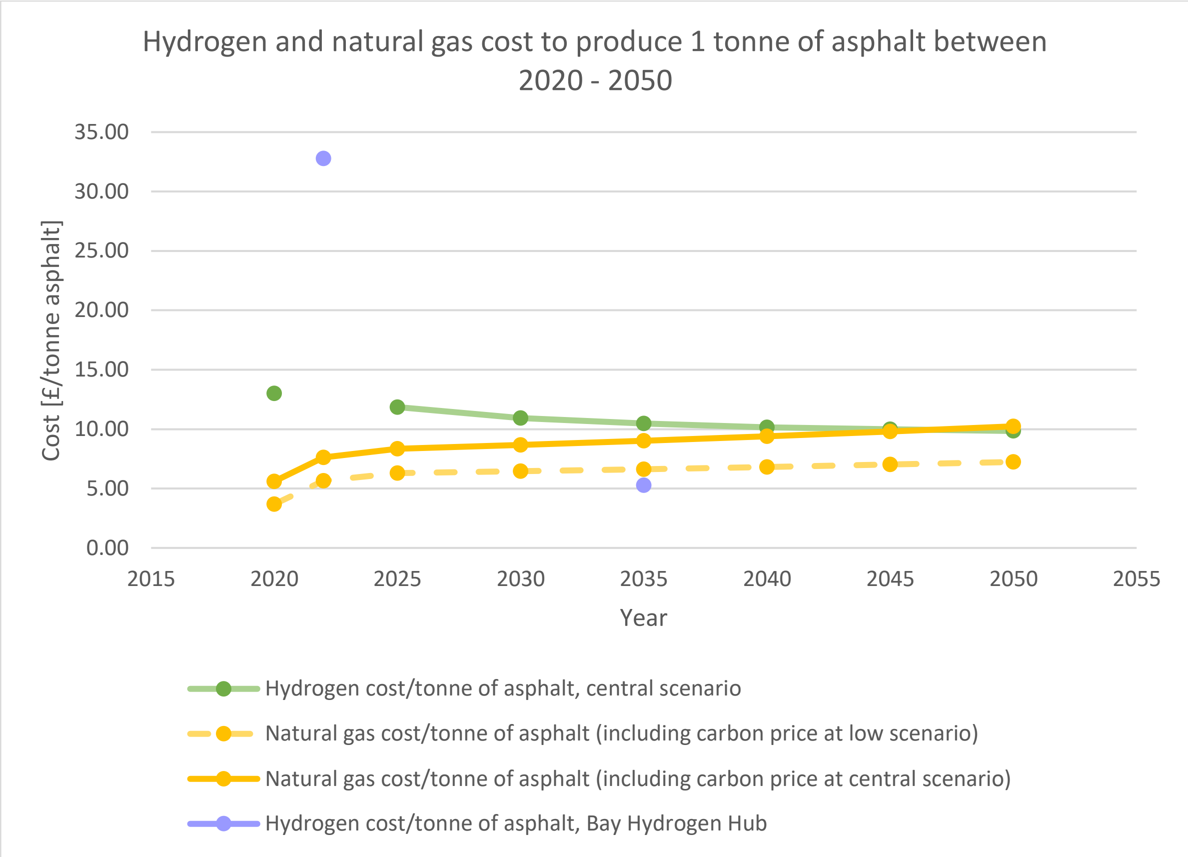

Figure 17 Fuel cost to produce asphalt - hydrogen vs. natural gas.

The analysis shows that even though Natural Gas (NG) replacement by hydrogen is not currently economically viable in asphalt manufacturing, this is expected to change by 2035, and hydrogen could be a lower cost option than NG. In 2035 the difference in fuel costs between NG (including carbon tax at central scenario) and low-carbon hydrogen is forecasted to be less than £1.5/tonne asphalt. Moreover, the proposed technology in this feasibility study indicates that further price reductions can be achieved by implementing the Bay Hydrogen Hub proposed solution. By 2035 Levelised cost of hydrogen (LCOH) is expected to be at 68 £/MWh for 100MW system, which could lead to hydrogen being more cost-effective fuel than NG as shown in the Figure 17. This indicates that cost of nuclear-derived hydrogen could decline faster with larger MW scale systems, which then could incentivise faster fuel switching to low-carbon hydrogen for those manufacturers that currently use NG.

NG price was assumed for high scenario included in the Green Book Annex Data 2022. The highest prices were taken due to the current energy crisis that disturbed trade flows and creates long-term uncertainty on the supply prospects in the coming years.

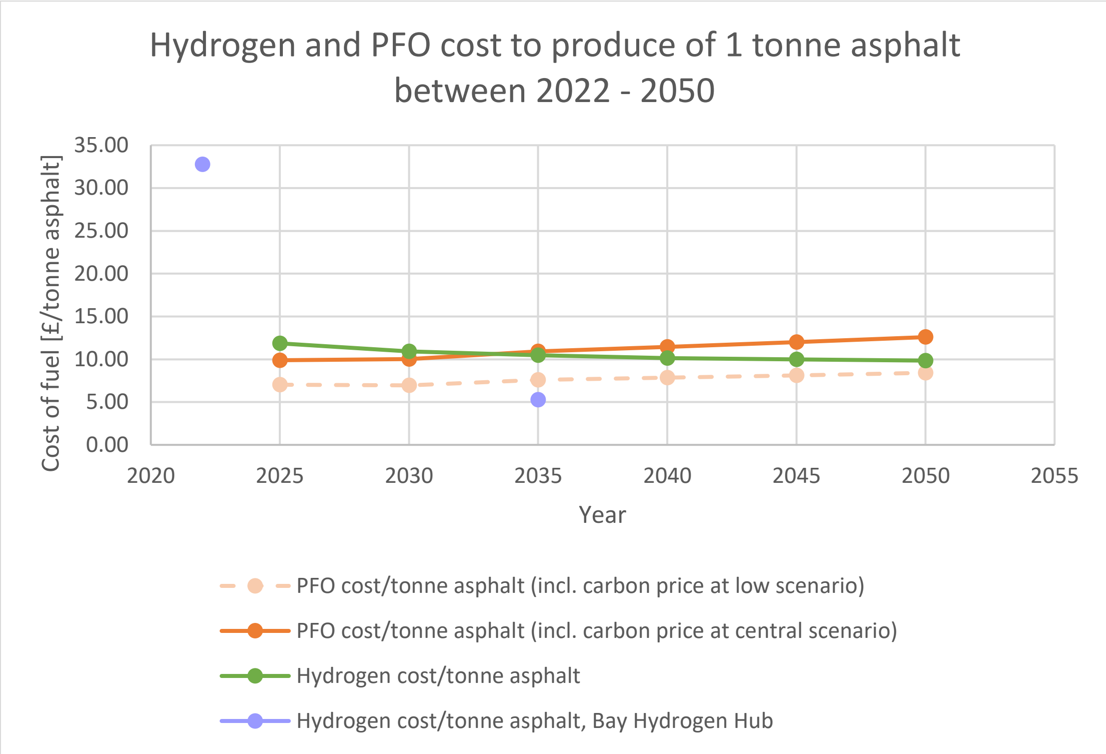

Figure 18 Fuel cost to produce asphalt - hydrogen vs. PFO

The PFO price assumed for 2022 is the same as in WP4 (End Use), forecasted prices of PFO has been estimated based on the Gas Oil prices trends (18) – assuming the trends will be identical for both PFO and Gas Oil.

In terms of comparison between PFO and low-carbon hydrogen costs producers of asphalt might not consider hydrogen as an economically attractive option as the cost is difference may vary between 2 and 5 £/tonne asphalt by 2025. However, similarly to the natural gas comparison, the situation is forecast to change by 2035 when the difference in fuel cost between PFO and low-carbon hydrogen will be at the same level or significantly lower. Both Figure 17 and 18 clearly show hydrogen cost production reduction for larger scale electrolysers. Bay Hydrogen Hub data for the cost of hydrogen in 2022 is considered for the 1MW demonstration electrolyser, however for 2035 a 100MW system is assumed, and the difference is significant.

1. Carbon tax

A carbon tax is a pricing mechanism designed to encourage businesses and individuals to reduce their greenhouse gas emissions. For manufacturers of asphalt and cement, that heavily rely on fossil fuels in their processes, carbon tax will increase the cost of using those fuels and ultimately could impact a product price making it less competitive on already price-sensitive markets. This may have a significant impact on their bottom line, as they may need to invest in new technology or infrastructure to reduce their emissions. Manufacturers of cement or asphalt that are able to adapt to these changes may see a competitive advantage long term, as consumers and investors increasingly prioritise sustainability. UK government strategy aims at incentivising them to switch to cleaner energy sources. Using data from Green Book (19), the carbon cost has been estimated for each sector (asphalt and cement) and added to the cost of fuel to show the full cost associated with using fossil fuels in the production process. It is important to note that the carbon tax is forecast to increase by 45% between 2025 and 2050 (central case), which could make hydrogen an even more attractive fuel proposition for both replacement of natural gas and PFO in asphalt production. Figure 17, 18. This could lead to increased demand for low carbon hydrogen, accelerate the development of the technology required to produce at scale and ultimately transform the energy landscape. More importantly, the increased adoption of low carbon hydrogen could have a significant impact on the emissions, as both asphalt and cement are responsible for a large portion of industrial greenhouse emissions. The availability of low carbon hydrogen at a competitive price could help the UK to achieve its emissions reduction targets. If low carbon hydrogen were at least at the same price as fossil fuel cost including carbon tax, it could have a transformative impact on the energy industry and help accelerate the

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transition to a low carbon economy. It is important to note that based on the Figures 17 and 18, carbon price for central scenario could be much more beneficial for investment in SOE technology than low carbon price scenario.

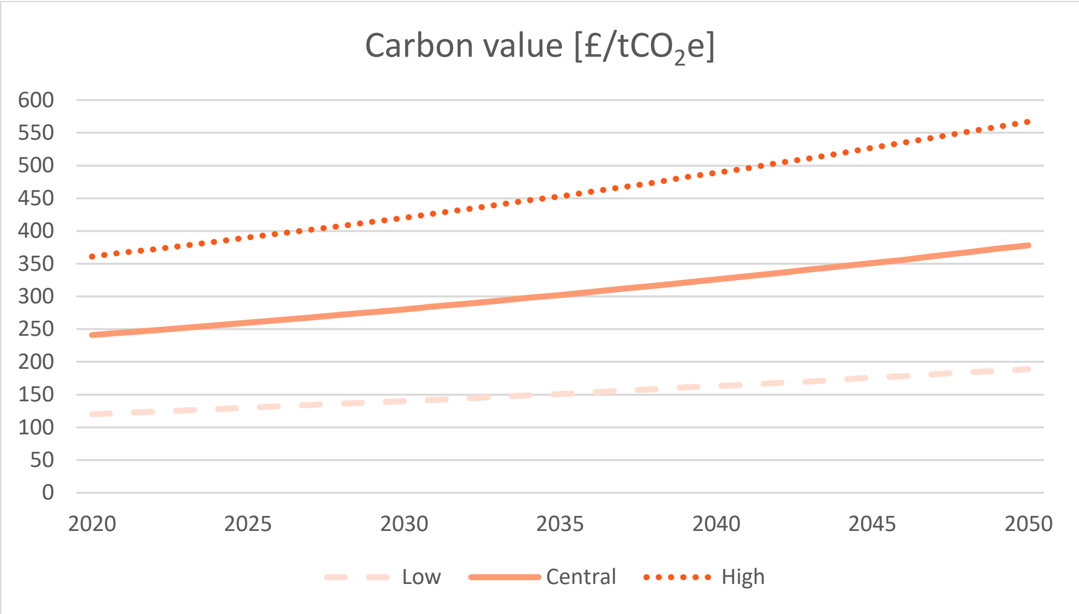

Figure 19 Carbon tax forecast for low, central and high scenario

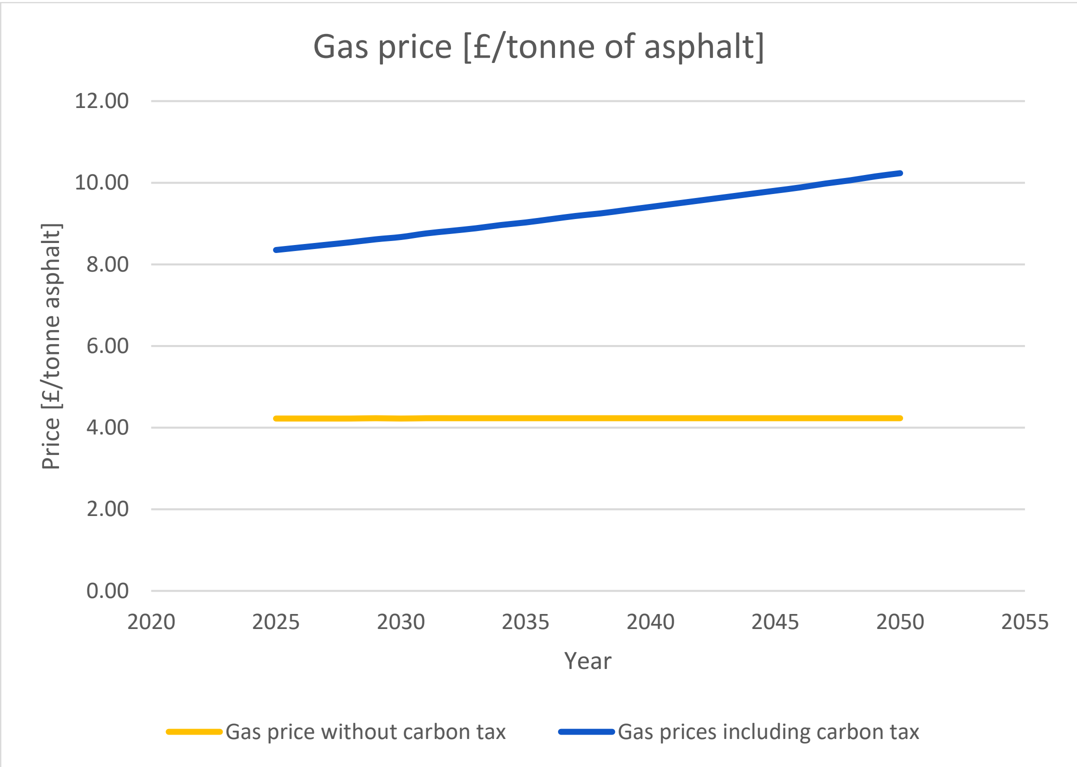

Figure 20 Example of carbon tax impact on natural gas price

Cement

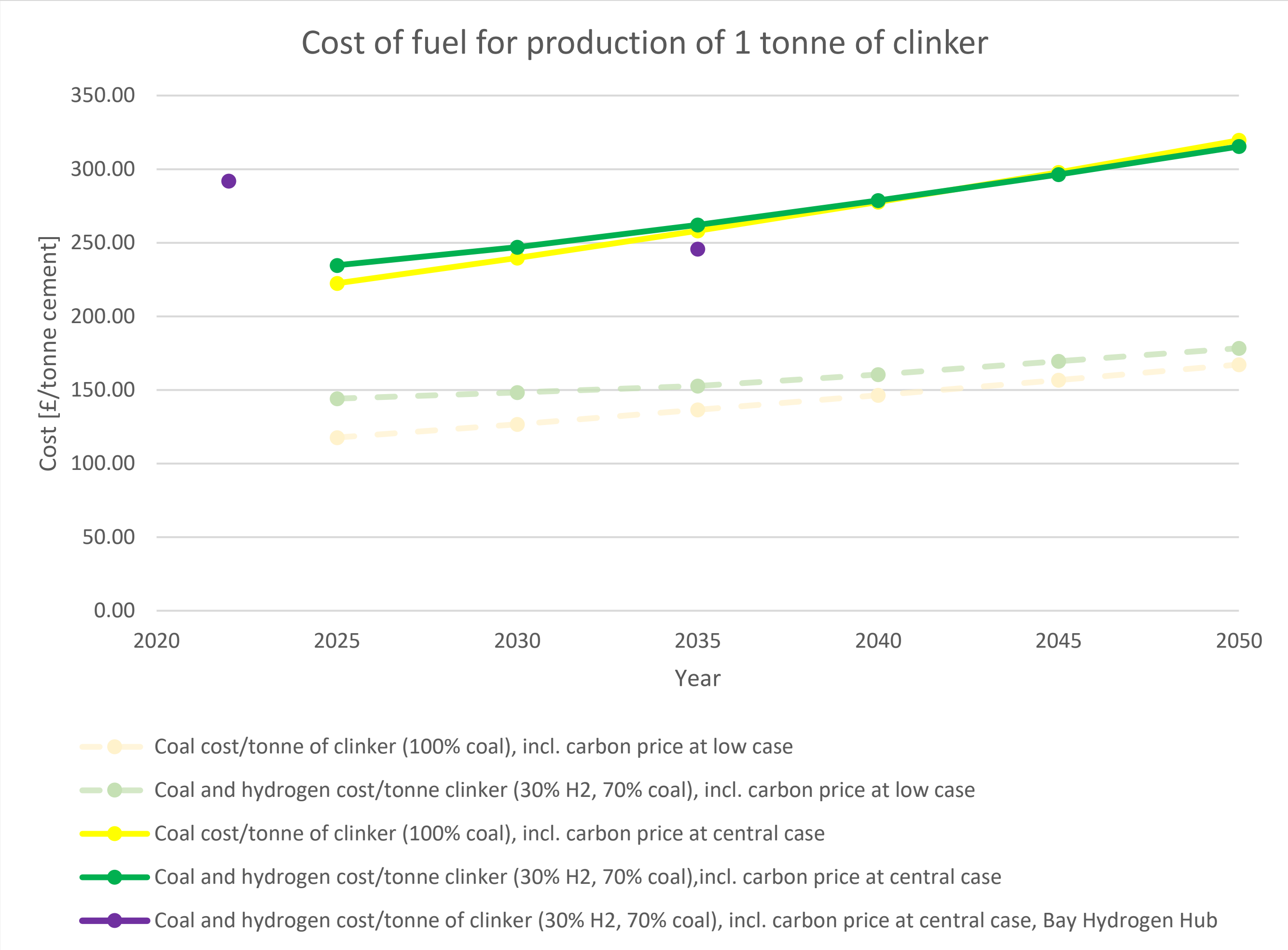

Figure 21 Fuel cost to produce cement - 30% hydrogen in the mix vs. 100% coal

Clinker production for cement consumes significantly more energy than asphalt production (c. 810kWh/tonne clinker) and even though it is already common in the industry to utilise net-zero fuels such as waste-derived fuels and biomass, the manufacturers are still heavily reliant on coal as a source of heat. The innovative concept proposed by Bay Hydrogen Hub is to use low-carbon hydrogen along with other low-carbon fuels as a fuel enhancer as the main burner might be sensitive to a fuel quality. For this cost analysis it was assumed that hydrogen would be at 30% of total energy required for clinker production and 70% would be coal that is commonly used in clinker production. Recent Hanson trials used 40% hydrogen in a mix with other net zero fuels. Considering the change to coal in the proposed blend a more conservative figure of 30% of hydrogen in fuel mix was applied for an indicative cost analysis.

The analysis shows that competitiveness of low-carbon hydrogen in the fuel mix strongly depends on carbon price. When considering central case of carbon tax level, it seems like 30% coal replacement by hydrogen would be economically viable option by 2040 (with Bay Hydrogen Hub solution this might be achieved at least 5 years earlier), However, if carbon price continues low case trajectory, it would be difficult for low-carbon hydrogen to be competitive, unless hydrogen cost is reduced.

Capital investment required at dispersed sites - Asphalt

Total investment identified for all the UK sites that reach annually approximately 28million tonnes sales (2021) of asphalt can be estimated at 17.6milion assuming conversion cost at 0.63£/tonne asphalt. Converting current asphalt sites would increase cost of production of asphalt by 1.3%. Currently and until at least 2035, this additional investment would require government support as there is no incentive to switch to low-carbon hydrogen which is forecast to have higher cost than current fuels until 2035 (for Bay Hydrogen Hub proposed scenario).

Replicability in other sectors

All heavy industry requires a significant portion of energy. Melting, sintering, drying and heating large furnaces all consume substantial amounts of heat. Industrial heat is a challenge in a variety of industries: chemical, iron and steel, aluminium, paper, glass, brick or ceramics as each manufacturing process is energy intensive and requires high temperatures. Currently, heat is generated by burning coal, oil and natural gas, which contribute to CO_2 emissions. Some of these emissions can be reduced by redesigning the energy intensive, and high-temperature processes to integrate the use of hydrogen. While for some processes electrification might be the most optimal solution, for others there is still requirement for heating furnaces where hydrogen can play an important role.

The use of hydrogen as a fuel in direct heating might be achievable in most of processes driven by direct and indirect heating, Figure 21. Since glass, ceramics and brick have multiple similarities to cement production, these sectors will be briefly reviewed in this section.

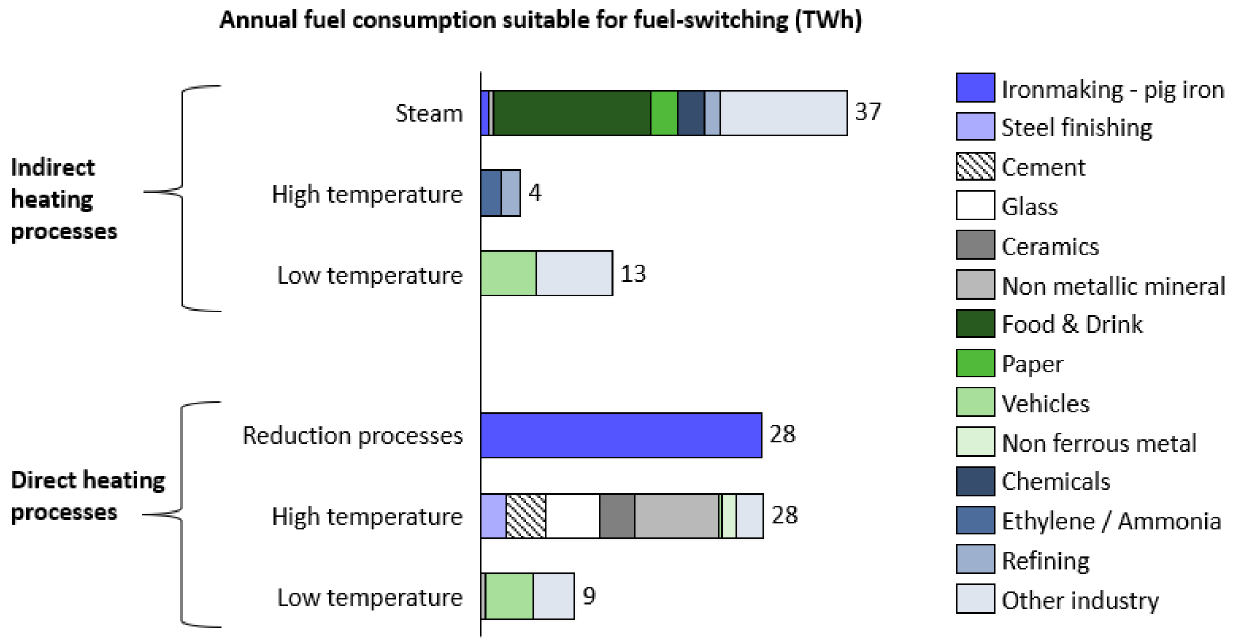

Figure 22 Annual fuel consumption suitable for fuel switching (TWh) (20)

Glass

Hydrogen can be used as a fuel source in glass production, specifically in the melting process of raw materials where temperatures required can reach even 1700ºC. In this process, hydrogen is used as a reducing agent to remove raw material impurities. Hydrogen as a fuel is not widely used in the glass industry yet and there are still some challenges that need to be addressed before it can be widely adopted: such as low-carbon hydrogen availability, safety, infrastructure, storage and transportation, and cost. However, in 2021, the UK glassmaker Pilkington managed to replace natural gas with hydrogen and manufactured sheet glass (21). Although low-carbon hydrogen was not used in the process, it still proved hydrogen utilisation feasibility in the sector.

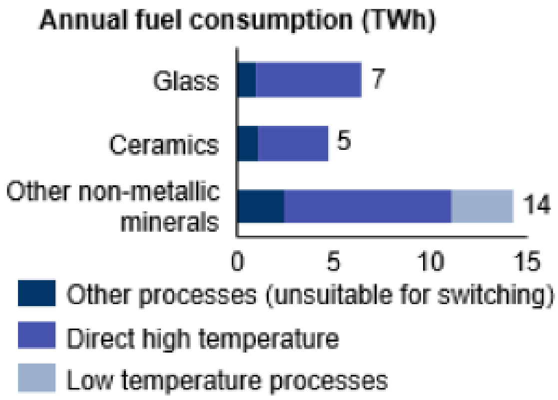

Figure 23 - Fuel consumption in glass, ceramics and non-metallic minerals, UK

Further research on the use of hydrogen is necessary, however German company SCHOTT, with 130 years of glass making experience, recently announced extensive research into hydrogen use in their manufacturing process. SCHOTT's sustainability agenda includes decentralised production of electrolytic hydrogen and its use in 35:65 volume ratio to natural gas with gradual increase of hydrogen quantity (22). These studies provide confidence in hydrogen usage in a safe and effective manner in glass industry and Bay Hydrogen Hub project could pave the way for switching to hydrogen not only in cement asphalt sector, but also in others where high temperatures are required and similar equipment is used(both cement and glass production process use rotary kilns as a primary equipment for heating the raw materials).

Ceramics

Hydrogen is a clean burning fuel that produces water vapour as a by-product, whereas traditionally ceramics industry relies on fossil fuels. Hydrogen can potentially be implemented in several operations of ceramic manufacturing, including:

- Kiln firing: Hydrogen can be used as a fuel source in kilns to heat ceramics during firing process which requires temperatures above 1000ºC
- Drying: Hydrogen can be used as drying agent to remove moisture from ceramics before they are fired
- Energy generation: Hydrogen fuel cells can be used to generate electricity and heat reducing dependence on fossil fuels and reducing emissions

One of the issues with firing hydrogen in kilns for ceramics is the impact of the increase water content in the flue gases. Ceramic materials must reach very low moisture contents but the reduction of moisture within the material must be controlled to prevent cracking. However, the British Ceramic Confederation has announced to investigate the concept of firing kilns with hydrogen up to 100% as the industry pushes towards net zero targets. Improvements in hydrogen economics and increases in carbon taxation will be required to make lower carbon fuels more economically viable.

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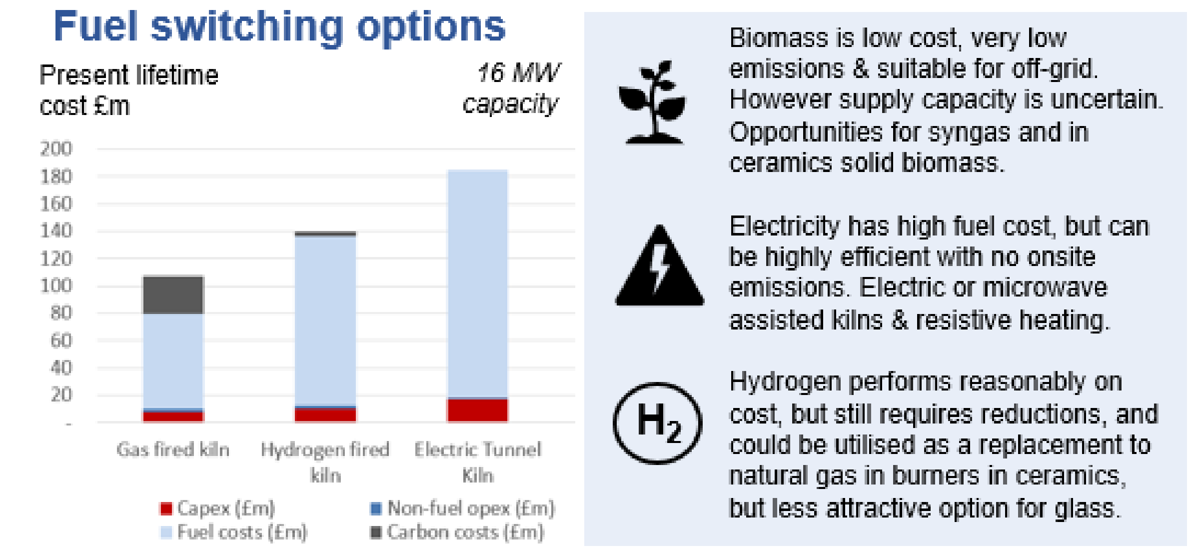

Figure 24 - Cost of using hydrogen or electricity in a kiln vs natural gas counterfactual (20)

Brick

The main source of CO_2 emissions in brick production comes from the firing process. In traditional brick production, clay or clay-based material are fired at high temperatures to form bricks. Brick manufacturing process is energy intensive as it requires temperatures above 1000ºC, and it traditionally uses fossil fuels such as coal and natural gas as a heat source. CO_2 emissions from brick production can vary depending on the different type of bricks (like clay bricks, fly ash bricks, concrete bricks), however, according to estimates they are in the range of 800-2000kg of CO_2 per one tonne of brick depending on the production process. These emissions not only come from fuel use but also from decomposition of limestone that is added as a fluxing agent in some brick production. Therefore, there are multiple ways of reducing emissions from this process

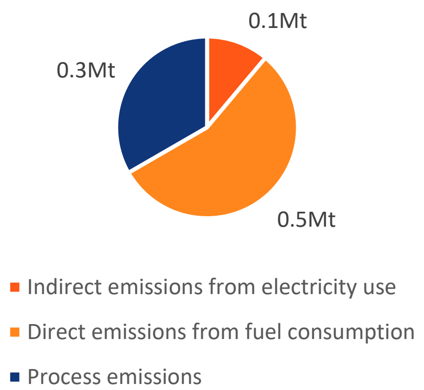

Figure 25 CO_2 emissions breakdown from brick manufacturing (27)

Hydrogen can be used as an alternative fuel providing heat energy required in the process, thereby reducing greenhouse gas emissions and air pollution. Replacing natural gas commonly used as a fuel in kilns or furnace to fire clay not only means lower carbon footprint, but also higher energy efficiencies. While hydrogen is not yet being used on a commercial scale to produce bricks, there have been some research and pilot projects to explore potential use of hydrogen as a fuel. One of the examples is Deep Decarbonisation of Brick Manufacturing Project led by brick manufacturer Michelmersh. The study aims to demonstrate feasibility of green hydrogen use as a fuel in brick clay production process (23). It is still in early stages and more work is required to demonstrate and optimise the process, but it is a promising technology for the future.

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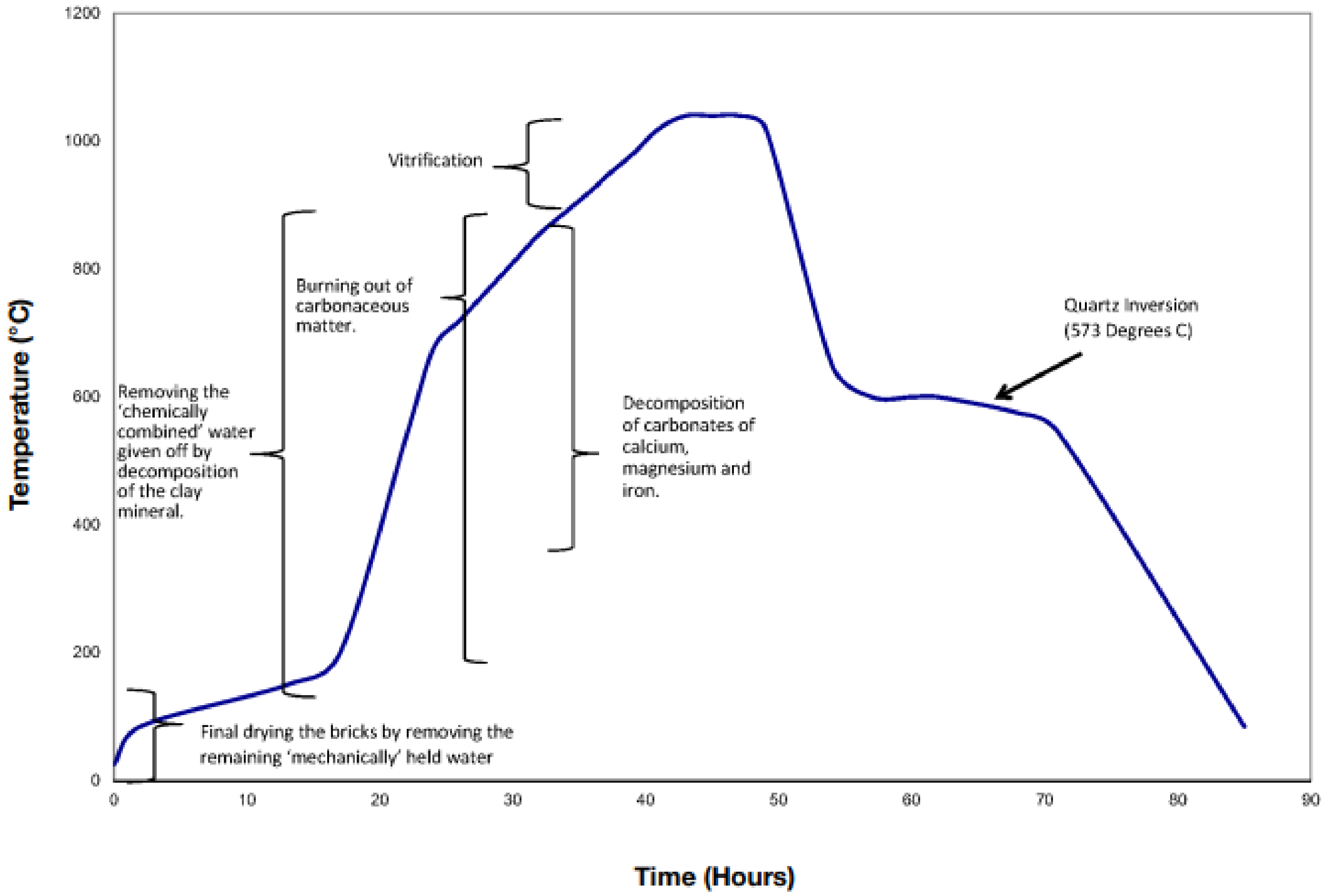

Figure 26 Idealised Time-Teamperatrure Profile (Firing Curve) (24)

Both asphalt and brick production processes involve the heating of raw materials to elevated temperatures to create a finished product. For asphalt, the raw material is typically a mixture of bitumen and aggregate, which is heated and mixed before laid as a road surface. For brick, the raw material is clay which is heated to produce the product. Those two production processes use similar equipment such as kilns for heating raw materials, hence in both production processes currently used fossil fuels can be replaced by hydrogen.

Mining

Mining in the UK has a long history but has seen significant decline in recent decades. The UK mining industry which includes the extraction of coal, metals, industrial materials, and construction materials, is relatively small compared to other sectors of the economy. However, it still plays an important role in the country's economy.

The main minerals extracted in the UK include coal, aggregates (sand and gravel), and limestone. Coal mining, which was one a major industry has declined significantly in the recent years due to availability of cheaper and cleaner energy sources and the phase out coal-fired power plants, Figure 21 (25).

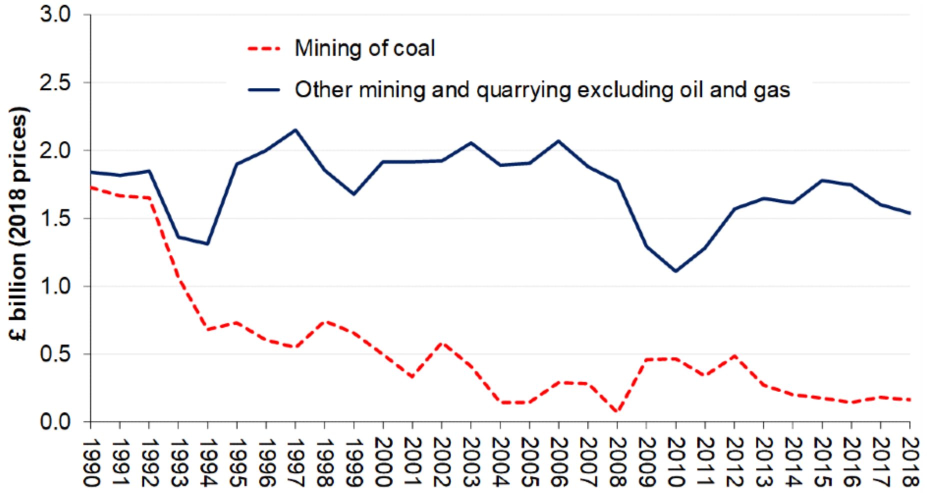

Figure 27 GVA of UK mining and quarrying (excluding oil&gas)

UK mining industry has faced several challenges, one of them is reducing its impact on environment. The industry needs to adopt clean and innovating solutions to meet the demand of a changing market. In the last decade, the industry has been investing in the technology and efficiency to minimise carbon footprint, such as the development of hydrogen fuel cells to power mining equipment and the use of modern technologies to reduce fossil fuel consumption in mining operations. Additionally, hydrogen fuel cells can be used to generate electricity for mining operations, which can reduce the need for grid-connected power. This can be especially beneficial for mining operations in remote locations where access to power grid is limited. Furthermore, hydrogen can be used to power a wide range of mining equipment, including trucks, excavators, and other heavy machinery.

There are number of developments in mining industry that aim at exploring and promoting potential of hydrogen in the mining sector. H2Bus - that is working on the next generation hydrogen trucks; HyDeploy - consortium led by Cadent aims to demonstrate feasibility of blending natural gas in the existing distribution network; HyNet North West - that aims to develop hydrogen production and distribution network in the North West of England to support decarbonisation, and more. These are just a few examples of the projects that could help mining industry switch to hydrogen. The focus of these projects is not directly mining industry, but their goal is to provide more hydrogen to the market and develop infrastructure necessary for the transition. Bay Hydrogen Hub project is another initiative that could support providing low-carbon hydrogen for the use in heavy transport and industrial sectors, and mining industry is one of them.

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Annex 3 – Social Value and Benefits

Department for Energy Security & Net Zero

NATIONAL NUCLEAR LABORATORY

Bay Hydrogen Hub – Hydrogen-4-Hanson

WP5 & WP6 – Social Value

Final Report
20th March 2023

In Partnership with:

BHH-H4H Feasibility Study funded by DESNZ [previously BEIS]' BEIS IHA Stream 2A | EDF R&D and Nuclear Generation | PROTECT – PRIVATE |

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Role	Name	Date
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Contents

Glossary

Acronym	Definition
AELP	Accelerated Experience and Learning Programme
BEIS	Department for Business Energy and Industrial Strategy
CO2	Carbon Dioxide
DESNZ	Department for Energy Security and Net Zero
ECITB	Engineering Construction Industry Training Board
GVA	Gross Value Added
GWP	Global Warming Potential
HGV	Heavy Goods Vehicle
IEA	International Energy Agency
IHA	Industrial Hydrogen Accelerator
IMechE	Institution of Mechanical Engineers
LCA	Life Cycle Assessment
MPA	Mineral Product Association
NDA	Nuclear Decommissioning Authority
NNL	National Nuclear Laboratory
NSSG	Nuclear Skills Strategy Group
SDGs	Sustainable Development Goals
SOEC	Solid Oxide Electrolysis cell
SQEP	Suitably, Qualified and Experienced Personnel
SRN	Strategic Road Network
STEM	Science, Technology, Engineering, and Mathematics
TWh	Terawatt Hours
UN	United Nations
WCSSG	West Cumbria Site Stakeholders Group
WNN	World Nuclear News

Executive Summary

Sustainability, social value and impact, are not an outcome of the work that we do, but the reason and context for it. Shared prosperity and an equitable transition from the carbon-based economy to a sustainable future which retains many of the technological and engineering gains of recent years are essential counterparts. A straight replacement of existing energy sources for carbon free ones will not on its own provide a solution and change of behaviours will also be necessary, alongside measures to adapt to mitigate the effects of global warming. Furthermore, it is imperative that we consider not only the picture in the UK, but that support is given to countries around the world, already experiencing more severe climate disasters than the UK, the effects of global warming. The United Nations (UN) adopted 17 Sustainable Development Goals (SDGs) in 2015, with the UK playing a leading role in their formulation, in particular the central pledge that there must be 'no one left behind'. The production of hydrogen using advanced nuclear and its use in foundation industries has a clear fit with several of the UN SDGs;

- Affordable and Clean Energy (SDG7)
- Decent Work and Economic Growth (SDG8)
- The intention to build resilient infrastructure, promote inclusive and sustainable industrialisation and foster innovation (SDG9 Industry, Innovation and Infrastructure)
- Sustainable Cities and Communities (SDG11, bringing in the use of hydrogen in the production of cement and related products)
- Climate Action (SDG13)
- Good health and well-being from improved air quality (SDG 3)

A project such as this, with its emphasis on sustainable growth and the development of innovative solutions to the key issues facing humankind - and more broadly life on earth, means that there are benefits that will be felt around the globe. Within the UK, increased skills and skilled employment will lead to reducing poverty (SDG1), reducing hunger (SDG2), good health and wellbeing (SDG3) and quality education (SDG4), while policies being pursued within the UK nuclear sector have increased the momentum towards gender equality (SDG5).

Skilled Employment

Decarbonising industry through hydrogen could lead to the creation of thousands of jobs, maintain existing jobs and upskill the current industrial work force. The UK Government indicates that the hydrogen economy could be worth over £900 million and provide 9,000 jobs by 2030, up to 100,000 by 2050. This analysis includes the whole value chain of hydrogen, from its production, through distribution to end use. Production of hydrogen utilising nuclear to meet the forecast demands for industry could provide between 18,000 and 59,000 jobs.

Scenario	Hydrogen Demand Estimate (TWh)		Estimated Fleet Requirement		Jobs after scaling	
	Central	Maximum	Central	Maximum	Central	Maximum
Industrial Use	25	105	5 SMRs/AMRs	20 SMRs/AMRs	18,001	59,403

The future requirement for refuelling stations, pipelines, and storage facilities dedicated for hydrogen, brings the opportunity not only creating thousands of new jobs, but could also lead to upskilling the existing workforce and the transfer of skills between industries. Workers involved in carbon-based fuel production, especially oil and gas, have significant knowledge and experience in handling and management of gas on hazardous sites. These transferable skills will be highly beneficial for hydrogen production from nuclear. Furthermore, the use of hydrogen at an industrial site will require training of current workers, providing more skills and greater future employment opportunities.

Additionally, accelerating hydrogen industrial uptake and its distribution by truck as a flexible and scalable method of transportation could also impact job creation. A 100MW electrolyser's output transported via truck could support 200 to 300 additional haulier jobs. Industry needs to start mapping out and understanding their future needs and skills required. The right tools such as certifications, health and safety procedures need to be introduced and provided to build the talent pool. Skilled jobs in the minerals sector demand average salaries of c.£71,000 per year[1], 20% above the national average for industrial work.

In its 2020 paper, the Nuclear Skills Strategy Group (NSSG) began to look at the skills required to deliver the range and scale of nuclear based energy vectors, noting that from the assumption of six reactors of gigawatt scale anticipated in 2018, this has become considerably larger. The six themes that it believes will deliver the skills required to meet this need include the opportunity for 'transferability' - with sites for nuclear new build spread across the country, there is potential for the replacement of jobs within existing energy sectors with new nuclear and hydrogen employment. There is an opportunity to mitigate the move away from jobs in carbon-based fuel production with new green jobs, in the process levelling up regions across the UK with high-value jobs. Essential is the need to 'excite the next generation' and particularly in that to diversify the workforce.

Community engagement and siting concerns

A challenge affecting all elements of new industrial installations, but particularly evident in public acceptance of nuclear energy, is the approach to siting and the method of consultation. Findings from the 2021 Department for Business Energy and Industrial Strategy (BEIS) 'public dialogue' which will inform any such approach were reviewed. An important finding was that it is essential not to impose nuclear reactors on communities, but to engage early to address concerns and provide a clear and transparent presentation of the facts about a next generation of nuclear and the needs it can meet. When this path is taken it suggests that there will be a reduced level of societal scepticism, better understanding and improved community relationships.

Gross Value Added (GVA) to UK Economy

To reach a global net zero target, it is crucial to decarbonise energy intensive industries that greatly contribute to greenhouse gas emissions. These include steel, cement, petrochemicals, mining, asphalt, and others. Global growth of population and urbanisation are set to drive demand for construction materials and the foundation industries have already started acting towards a net zero future. The cement and asphalt industries are fundamental to total GVA in the UK economy. Estimates in 2013 indicate that the cement industry alone contributed £329m in GVA and was part of a total minerals and extraction industry GVA of c.£30bn, that formed the foundation of the UKs 2013 £1.5tn economy.

The Mineral Product Association (MPA) indicates that import levels of cement have been increasing over recent years, and now UK manufacturers are not satisfying all national demand. One of the main reasons is that customers are looking into construction materials with low carbon footprints that are currently not available on the market in large quantities. Currently, more than 20% of the UK cement demand is being fulfilled by imports, this trend can negatively impact employment in the industry. However, switching from fossil fuels to low-carbon hydrogen could support reversing this trend and even increase export market for cement. Decarbonising quickly may ensure these markets are not lost to competing businesses internationally, however this must be done in a way that does not negatively impact 'business-as-usual' operations, nor at a cost that reduces the competitiveness of UK plc products. Lowering emissions from manufacturers will also contribute to higher living standards as local air quality will improve – hydrogen, when burned, produces only water vapour as a product, unlike fossil fuels which emit harmful pollutants (Carbon Monoxide , Sulphur Dioxide and Nitrogen oxides), which contribute to air pollution and have negative impacts on human health.

(the Minerals industry)…… contributed £16bn in turnover to the UK economy in 2018, with over 2,000 active sites and plants, and supported an additional 3.5 million jobs throughout the supply chain. The UK Mineral Products industry is highly productive: each worker produced about £71,000 in 2018, 20% higher than the national average.[2]

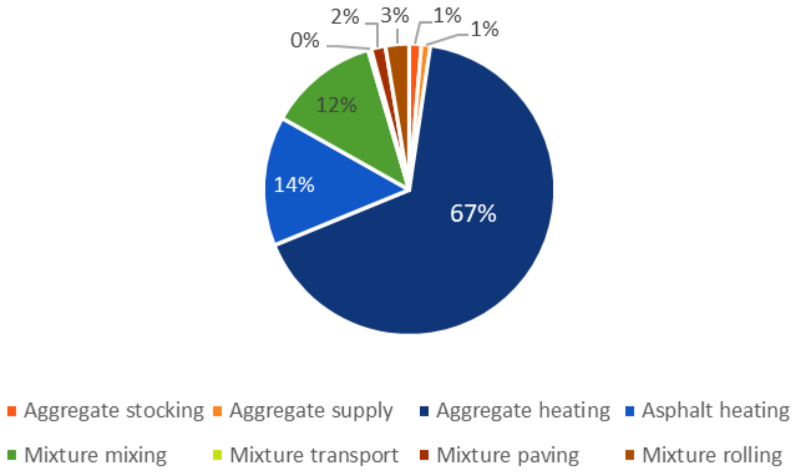
[1] https://www.mineralproducts.org/MPA/media/root/Publications/2022/MPA_SD_Report_2022.pdf

[2] https://www.mineralproducts.org/MPA/media/root/Publications/2022/MPA_SD_Report_2022.pdf

Carbon Dioxide (CO_2) Emissions Reductions

The production of nuclear derived hydrogen and its use in the asphalt and cement sectors offers some important advantages, but what really stands out is the potential savings in CO_2 emissions. Dispersed sites in the UK contribute significantly to the country's carbon footprint, emitting around 33.6 million tonnes CO_2e annually.

Cement and asphalt plants are often isolated from industrial clusters. Switching from the fossil fuels currently used in the asphalt production process to hydrogen could save 0.56 Mt of CO_2 emissions annually, with greater than 80% of emissions associated with fuel combustion. This equates to a 1.6% reduction in emissions from non-clustered sites, an important step towards the UK's goal of tackling climate change.



Initial calculations indicate that with just a c.2% blend of H_2 by energy, the proportion of low-cost lower-carbon waste derived fuels increases (by c.5%) such that 6kgCO_2e per tonne of clinker can be saved, which equates to c.42kT annually from the UK cement industry based on 7m tonnes of production. Furthermore, just using hydrogen blends up to 30% by energy alongside coal, total emissions from the UK cement industry (6.28MT in 2021) could be reduced by 0.56 MT, a reduction of 9% per year, without considering the potential increase of waste derived fuels, which could make up the remaining fuel mix, potentially reducing cement combustion emissions to close to 0 (1.7MT reduction per year nationally).

Dissemination

The main objective of the knowledge dissemination activities was to maximise the impact of developing a solution of electrolytic hydrogen production using heat and electricity from nuclear station and low-carbon hydrogen deployment in cement and asphalt industry. Dissemination activities included press announcements through LinkedIn and consortium partners websites at launch of the project and EDF internal webinar. The project received many positive comments and all the activities received significant attention from people in industry and academia. The Bay Hydrogen Hub project was also featured in the news of New Civil Engineer and World Nuclear News. In addition, an in-person event organised by Institution of Mechanical Engineers (IMechE) is planned to further disseminate knowledge after final report submission.

1. Impact and Benefits

Sustainability, social value and impact, are not an outcome of the work that we do, but the reason and context for it. Shared prosperity and an equitable transition from the carbon-based economy to a sustainable future which retains many of the technological and engineering gains of recent years are essential counterparts. A straight replacement of existing energy sources for carbon free ones will not on its own provide a solution and change of behaviours will also be necessary, alongside measures to adapt[3]. Furthermore, it is imperative that we consider not only the picture in the UK, but that support is given to countries around the world, already experiencing more severe climate disasters than the UK, the effects of climate global warming.

A detailed picture of demand past 2030 is difficult to predict. The changing pattern of behaviours and system changes might include, for example, increased provision and use of public transport, a reduction of private transport, self-driving vehicles, shared ownership schemes, changes in food production, land use, hybrid working patterns, amongst those readily imagined at this stage. It is nevertheless possible to foresee several scenarios that might combine to make up the complex picture of future needs and from that to extrapolate potential opportunities. This in turn will facilitate timely decisions that lead to optimum levels of social impact that benefit and contribute the most to government agendas including the growth economy and levelling up.

The United Nations (UN) adopted 17 Sustainable Development Goals (SDGs) in 2015[4], with the UK playing a leading role in their formulation, in particular the central pledge that there must be 'no one left behind'.

In 2019, the UK Government described what this means[5]

"It is a recognition that when people are marginalised or excluded, societies are less stable and economies are weaker. When people are left behind, everyone suffers the consequences.

At all levels the UK works to understand who, where, and why people are being left behind; include people by delivering targeted programmes and services to those who are seldom heard; and empower people to be agents of change by working with others to challenge discrimination and harmful social norms."

The SDGs demonstrate the interdependency of economic, social and environmental sustainability, often referred to as the three pillars. Another read across of the SDGs is also helpful, the five Ps: People, Planet, Prosperity, Peace and Partnership.

The production of hydrogen using advanced nuclear and its use in foundation industries has a clear fit with several of the UN SDGs, from A*ffordable and Clean Energy* (SDG7), *Decent Work and Economic Growth* (SDG8), and the intention to build resilient infrastructure, promote inclusive and sustainable industrialisation and foster innovation (SDG9 *Industry, Innovation and Infrastructure*), to *Sustainable Cities and Communities* (SDG11, bringing in the use of hydrogen in the production of cement and related products), and *Climate Action* (SDG13). A project such as this with its emphasis on sustainable growth and the development of innovative solutions to the key issues facing humankind and more broadly life on earth, means that there are benefits that will be felt around the globe. Within the UK, the increase in skills and skilled employment that is created will lead to reducing poverty (SDG1), reducing hunger (SDG2),

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[3] *The agreement at the recent COP27 in Egypt on a new funding arrangement for loss and damage will help those countries most affected by climate disasters. And the COP27 negotiations prompted new commitments from the rich world to help, including from the UK which pledged to triple its international funding for climate adaptation. (Sir James Bevan)*

[4] https://sdgs.un.org/goals

[5] *As part of Agenda 2030, the 193 UN member states are required to produce at least one Voluntary National Review, a report in which they assess and present progress they have made towards achieving the SDGs. In 2019, the UK produced its first Voluntary National Review.*

good health and wellbeing (SDG3) and quality education (SDG4), while policies being pursued within the UK nuclear sector have led to a momentum towards increasing gender equality (SDG5).

In order that the impact is optimised and works towards the range of SDGs set out here, the siting of new facilities will be vital. This is addressed within the feasibility study, as it is important not just for social value, but for industrial and technical reasons.

The following sections set out how the impacts deriving from nuclear produced hydrogen, distribution by truck and use in industry vary across the range of options depending on the number of its applications. It assesses the number of jobs and the skills required across those scenarios, and the potential this has for the 'levelling up' agenda, that seeks to address the people focused SDGs 1-4.

The UK's first Voluntary National Review on progress towards its UN SDG targets[6] emphasises that:

> *"Technology offers unprecedented opportunities to rethink the way in which the Goals are tackled. The UK's technology sector has the potential to play a leading role in this... The UK has four of the world's top 10 universities and produces more than 5,000 Science, technology, engineering, and mathematics (STEM) PhDs each year. World-class expertise in Artificial Intelligence and deep tech, as well as advanced robotics, advanced manufacturing and automotive experts are contributing to responsible, sustainable growth"*

2. Socio-Economic Impact

2.1. Nuclear derived hydrogen

The distribution of sites for nuclear (black dots in Figure 1) presents opportunities to contribute to the ambitions that 'no one is left behind' and of the levelling up agenda. If well-managed and timed, the programme might potentially provide a supply of high-quality and long-term jobs that, with the right training, can mitigate the effects of a move away from carbon fuels. There will though necessarily be transient skills during new build periods and learning from comparable projects, such as Hinkley Point C, will be essential to ensure that maximum long-term benefit to the localities concerned is achieved.

Table 1 below quantifies an estimate for the number of jobs associated with nuclear coupled with a hydrogen plant providing the energy source for each of the potential sectors. Figures for both the central and maximum levels are provided. The numbers are such that should even a fraction of the central level of scaling for industrial-use nuclear deployment be achieved, a substantial skills pipeline is necessitated and the socio-economic impact in areas of the country that are most in need of highly-paid, skilled jobs, will be similarly substantial.

[6] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/818212/UKVNR-web-accessible1.pdf

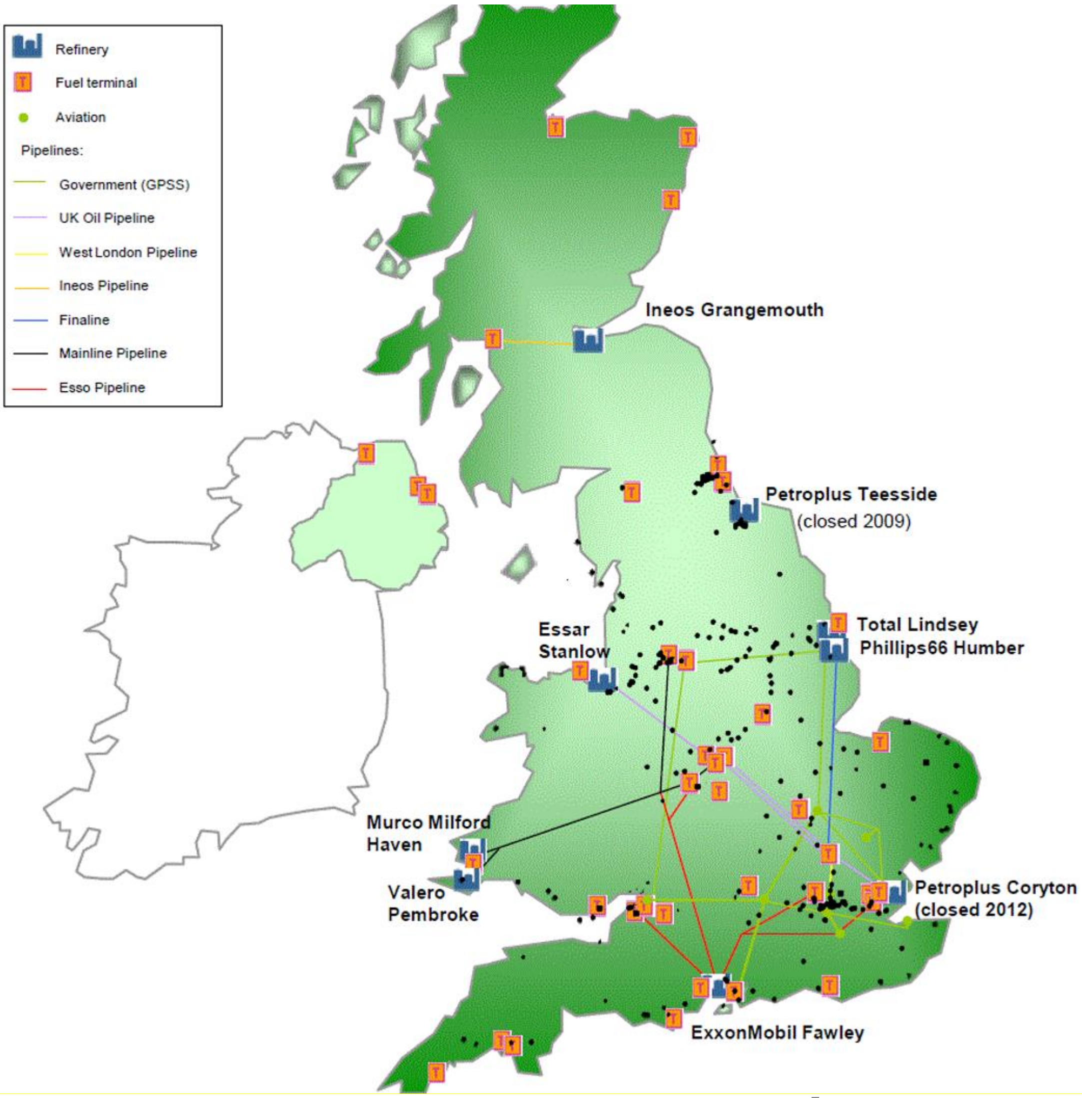

Figure 1- Showing potential nuclear sites presented by the Energy Technologies Institute[7](black dots) compared to locations of existing and recently decommissioned oil and gas refinery sites[8]

[7] https://www.eti.co.uk/library/power-plant-siting-study-summary-report-andpeer-review-letters
[8] https://publications.parliament.uk/pa/cm201314/cmselect/cmenergy/340/34003.htm

Scenario	Hydrogen Demand Estimate (TWh)		Estimated Fleet Requirement		Jobs after scaling	
	Central	Maximum	Central	Maximum	Central	Maximum
Building Heating	100	210	3xGW Scale Reactors *(Assuming 2 units per reactor site)*	6xGW Scale Reactors	20,370	40,060
Power	25	40	2 Conventional Reactors *(Assuming 2 units per reactor site)*	4 Conventional Reactors *(Assuming 2 units per reactor)*	9,520	19,040
Transport	75	140	2 GW Scale Reactors	4 GW Scale Reactors	13,580	27,159
Industrial Use	25	105	5 SMRs/AMRs	20 SMRs/AMRs	18,001	59,403
International Sale	100	200	3 GW Scale Reactors *(Assuming 2 units per reactor site)*	6 GW Scale Reactors *(Assuming 2 units per reactor)*	20,370	40,060

Table 1- Estimates for Job Creation for Nuclear-Thermochemical plant deployment in Central and Upper Demand Scenarios. This estimate assumes that all of the BEIS central or maximal estimate for hydrogen demand is met by nuclear, and so is estimated to reflect the potential for nuclear deployment in this market. It is anticipated that nuclear deployment will, in reality, meet a fraction of this central or maximal estimate as part of a diverse energy mix. Additionally, this estimate assumes 'learning-by-doing' for nuclear deployments within each sector, but no learning that transfers between each scenario.

2.2. Hydrogen distribution

Some of the main challenges for hydrogen are lack of refuelling stations, pipelines and storage facilities, but it also brings an opportunity for creating thousands of new jobs and upskilling existing workforce within distribution and delivery. Currently, sustainable hydrogen constitutes a small portion of the energy workforce, however with the UK government targets and future plans to expand the hydrogen economy, employment will gradually grow and will require highly skilled workers.

In 2020, there was a sharp decline of employment in the oil industry due to reduced crude oil prices triggered by Covid-19 pandemic, additionally, there is a trend of workers shifting their careers into clean energy. There will be more changes in energy industry employment with the transition towards a low-carbon future that need to be addressed, such as increased electrification, reduced natural gas distribution. Chemical engineers, process engineers and other skilled workers from refineries can apply their knowledge to midstream hydrogen pipeline distribution, servicing and handling operations.

An inclusive energy transition is a vital element and needs to be considered when choosing future sustainable technologies, specifically when looking at the number of people employed in the sectors that will become obsolete while transitioning towards a zero-carbon future, Figure 2.[9] Project Union (connecting hydrogen production, storage and demand to enable net zero and empower a UK hydrogen economy through repurposing existing transmission pipelines), is a good example of natural gas distribution network transitioning towards hydrogen, where benefits are not only related to good connectivity of end-users to hydrogen, but also providing 3,100 jobs at the peak construction[10] – and this is only for the one part of the supply chain of hydrogen. When more companies explore the option of switching to hydrogen and decide to do so, there will be new opportunities throughout the whole value chain. In 2016 the level of employment in gas sector was 45,000, according to the UK Government. Existing natural gas network will gradually start transmitting greener gasses such as biomethane and hydrogen, hence finding a demand for these gases in industry and retain employment in the gas network sector will be important.

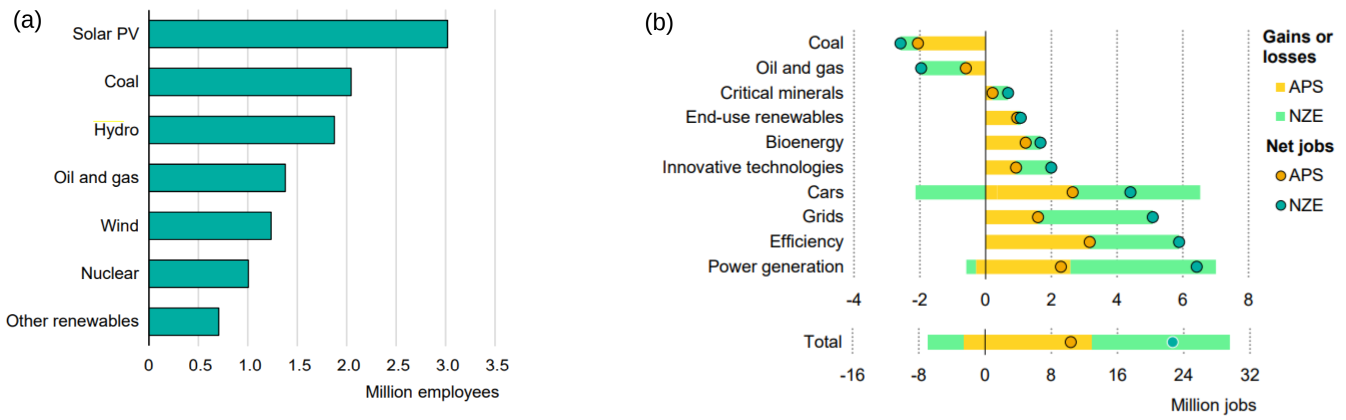

Figure 2 (a) Global employment in power generation by technology, 2019 (b) Global employment by scenario and by subsector, 2019-2030[9]

To accelerate the uptake of hydrogen, distribution by truck is a flexible, scalable method of transportation. However, there will be key challenges with this for the UK, based on recent experience during 2022 post the Covid-19 pandemic. Severe Heavy Goods Vehicle (HGV) driver shortages led to a shortfall of c.76,000 HGV drivers[11]. Furthermore, the average age of HGV drivers is 48-50, indicating an aging workforce in 2022. The identification of this shortfall has led to increases in driver training, further funding from UK government, and opportunities for new entrants into the industry. A single 100MW electrolyser installation transporting hydrogen via truck rather than pipeline could support 200-300 additional HGV jobs dependent on routes and utilisation rates. The higher electrolyser utilisation rates of nuclear would support more distribution jobs than variable renewable powered electrolysis unless they were also connected to a low-carbon grid.

2.3. End use within Asphalt, Cement and other industries

To reach a global net zero target, it is crucial to decarbonise energy intensive industries that greatly contribute to greenhouse gas emissions. These include steel, cement, petrochemicals, mining, asphalt, and others.

Global growth of population, urbanisation and low-carbon agendas is set to drive demand for construction materials and the foundation industries have already started acting towards a net zero future. This means that industries that can implement hydrogen in their plants operations will require new safety standards and procedures, training of existing employees and in some cases new employees. The lower emissions from industrial factories that switch to zero carbon fuels will also contribute to higher living standard as a local air quality will improve.

[9] *Global Hydrogen Review International Energy Agency (IEA), 2021*

[10] *https://www.nationalgrid.com/gas-transmission/document/139641/download*

[11] *https://www.fleetpoint.org/fleet-management-2/driver-shortage/why-the-uk-is-struggling-with-driver-shortages/*

Furthermore, the cement and asphalt industries are fundamental to total GVA in the UK economy. Estimates in 2013 indicate that the cement industry alone contributed £329m in GVA and was part of a total minerals and extraction industry GVA of c.£30bn that formed the foundation of the UKs 2013 £1.5tn economy.

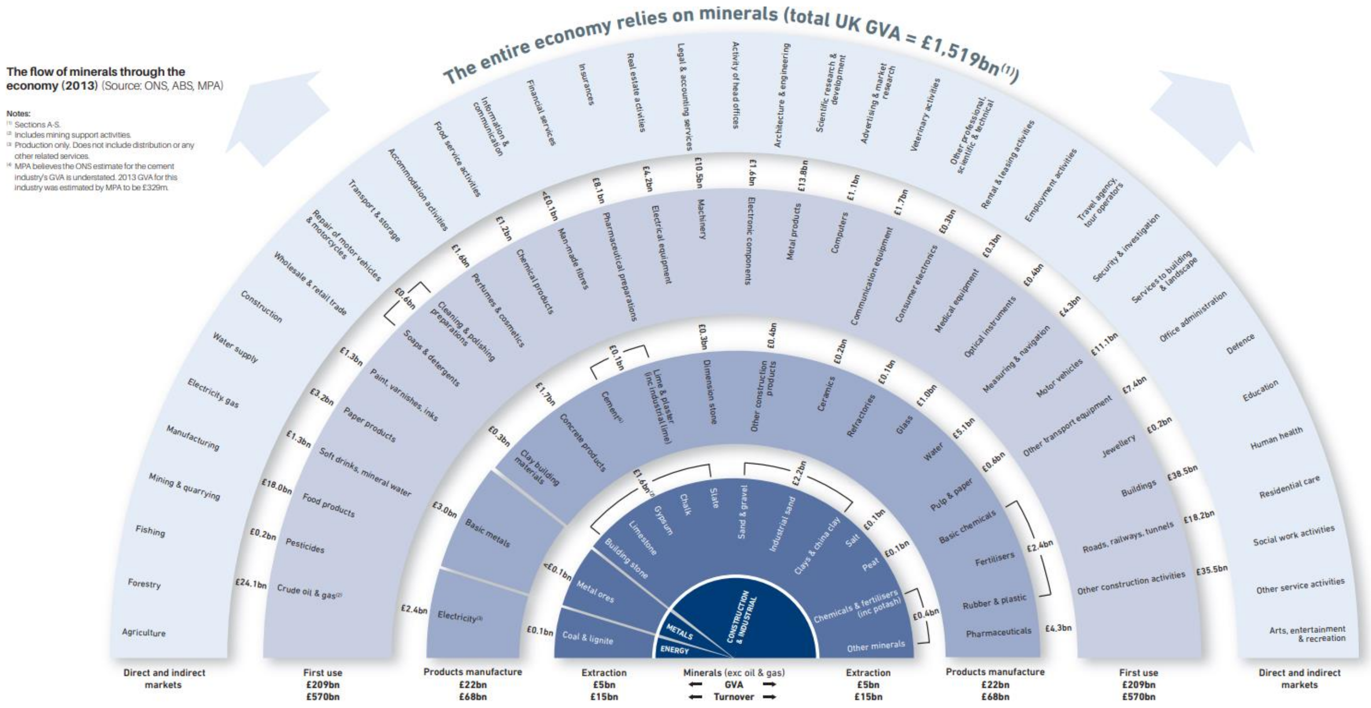

Figure 3 - UK GVA (MPA[12])

The risk of not decarbonising and setting the agendas for energy-intensive industries can lead to supply chain interruptions in the future, as climate change will initiate macro and micro-economic disruptions. Water supply or feedstock shortages are predicted to be a challenge if greenhouse emissions keep rising – that could have severe implications and shift the priorities of governments and businesses. Additionally, on a more local level, the risk of lack of decarbonisation action within industry can have an impact on other aspects.

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The Mineral Product Association (MPA) indicates that import levels of cement have been increasing over recent years, and now UK manufacturers are not satisfying all national demand. One of the main reasons is that customers are looking into construction materials with low carbon footprints that are currently not available on the market in large quantities. Currently more than 20% of the UK cement demand is being fulfilled by imports, this trend can negatively impact employment in the industry, Figure 4.

[12] https://www.mineralproducts.org/MPA/media/root/Publications/2022/UK_Minerals_Strategy_2022.pdf

[13] https://www.mineralproducts.org/MPA/media/root/Publications/2022/MPA_SD_Report_2022.pdf

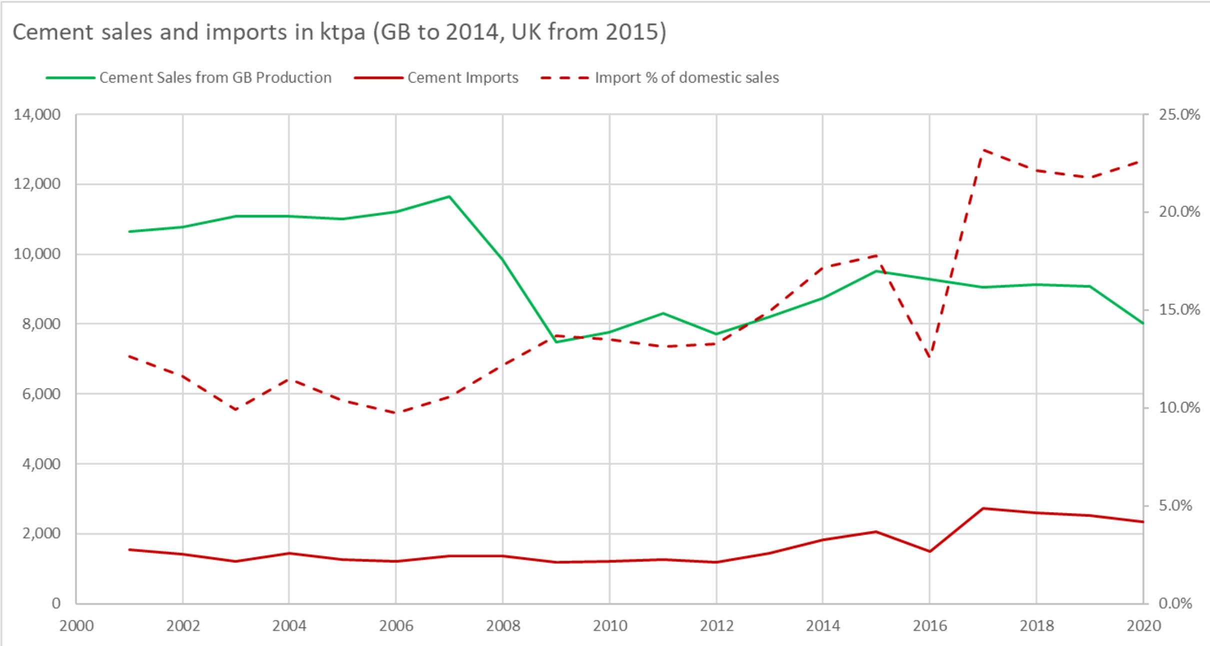

Figure 4 – GB and UK Cement sales and imports (MPA[14])

The cement industry example is not unique, and similar issues can be seen in other industries. There is an opportunity for new commodity markets to emerge and support decarbonisation of energy intensive industries, and hydrogen is a strong candidate across industrial applications.

Asphalt is the building block of UK road infrastructure and is essential to connecting people, businesses, enabling new projects, recycling decommissioned ones and supporting growth of the UK economy. National highways have four pillars to their social value plan:

- Delivering economic prosperity by supporting the UK economy, skills, education and apprenticeships
- Improving the environment by developing a net zero business
- Community wellbeing through promotion of safer, healthier travel and local engagement
- Equality, diversity and inclusion: creating a more accessible, inclusive road network

Figure 5 – National Highways Social Value Pillars[15]

Highways England 'Road to Growth' plan in 2017 indicated that the Strategic Road Network (SRN) is relied upon by businesses employing 7.4 million people and contributing over £314bn in GVA to UK economy. Low-carbon Asphalt production would ensure that the maintenance and upgrading this road network reduces the carbon emissions associated with this interconnectivity[16].

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[14] https://cement.mineralproducts.org/MPACement/media/Cement/Industry-Statistics/2022-07-04_Annual_cementitious.pdf

[15] https://nationalhighways.co.uk/media/tdog2fma/ccs0622297296-003_social-value-strategy-report_final.pdf

16 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/600275/m160503_the_road_to_growth_Our_strategic_economic_growth_plan.pdf

3. Skills Development

3.1. Nuclear

The Nuclear Skills Strategy Group (NSSG) has begun to look at the skills required to deliver the range and scale of nuclear based energy vectors, noting that from the assumption of 6-gigawatt scale reactors anticipated in 2018, this has become considerably broader (NSSG 2020 strategy[17]). With sites for nuclear new build spread across the country, there is potential for the replacement of jobs within existing energy sectors with new nuclear and hydrogen, with this the opportunity to mitigate the move away from jobs in carbon-based fuel production with new green jobs, in the process levelling up regions across the UK with high-value jobs.

Transportation - there is an opportunity for siting to play a key role in the levelling up agenda as discussed within 'Unlocking the UK's Nuclear Hydrogen Economy to Support Net Zero: A Cross-Sector Action Plan for Consideration by the Nuclear Industry Council'.[18] Figure 1 shows that potential new nuclear sites in some instances provide an opportunity for close correlation with existing or recently decommissioned oil and gas refinery sites. The NSSG 2020 Strategic Plan[19] highlights how EDF have re-skilled people from the workforce of its Cottam coal fired power station:

> *"ECITB (Engineering Construction Industry Training Board) is funding the Accelerated Experience and Learning Programme (AELP) which builds upon existing operational and generic knowledge and skills. Those on the programme are experienced individuals who are technically competent, and the course recognises these skills and tops them up with the elements required to ensure they meet the Suitably, Qualified and Experienced Personnel (SQEP) criteria required by the nuclear sector."*[19]

It is also worth noting that the workforce from carbon-based fuel production, specifically oil and gas has significant knowledge and experience in handling and management of gas on hazardous sites, highly beneficial transferable for hydrogen production from nuclear.

The NSSG strategy sets out six themes that it believes will deliver the skills required for future nuclear requirements, from Enhanced Skills Leadership, which highlights taking responsibility for the 'strategic direction for developing a diverse future workforce'. This theme also looks to understand the resource demand picture, which would include the skills required to deliver the hydrogen agenda.

The second theme is sector transferability, which is particularly relevant in areas where levelling up is an issue, where skills may have been acquired in other industries that will no longer be required as deep decarbonisation takes place. The NSSG strategy then highlights pathways and apprenticeships, stating "We are particularly aiming to diversify the applicants to these schemes, reaching out to people that might not have traditionally considered nuclear, to ensure that they can benefit from the economic value associated with our sector." The strategy points to T Levels (a two year technical programme equivalent to 3 A-Levels) and the apprenticeship levy as ways to help to level up the economy.

Essential is the need to 'excite the next generation'. NSSG highlights a pilot programme which uses virtual and simulation technology to overcome the potential barriers to hosting placements for young people on restricted sites.

A theme that cuts across the six is diversifying the workforce and this is something that is also highlighted in the strategy risk table. A failure to get sufficient diversity into the talent pipeline will lead to a loss of 'diversity of thought' and a failure to think differently and challenge the status quo.

Since its last Nuclear Workforce Assessment in 2019, which envisaged two scenarios with between 3 and 6 further GW-scale power stations, starting with Hinkley Point C coming online in 2026, there has been a considerable move

17 https://www.nssguk.com/media/2577/nssg-strategic-plan-2020-delivering-through-partnership-final-spread.pdf

18 https://www.nnl.co.uk/wp-content/uploads/2021/07/Hydrogen-Round-Table-FINAL-v2.pdf

19 https://www.nssguk.com/media/2577/nssg-strategic-plan-2020-delivering-through-partnership-final-spread.pdf towards a larger role for nuclear. The report noted also that this represented a considerable change in the landscape from its 2017 assessment, in particular 2018's Nuclear Sector Deal 'a pivotal moment for the industry'.

The larger scenario, providing an additional 18GW from six new plants, presents the workforce requirement topping 105,000 between 2025 and 2030, before dropping off with the decommissioning of existing operations. This would require an inflow of 4,800 new workers per year in the six years to 2025 and by 2030, a total of 60,000 full time posts would need to be filled across business, operations, science and technology, engineering, project management and trades.

3.2. Distribution and end use

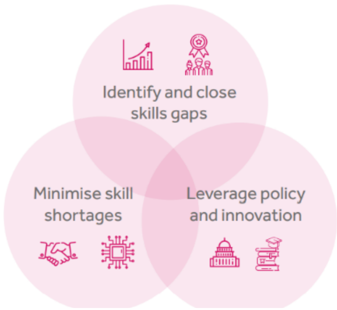


Figure 6- Key areas of action (ECITB)

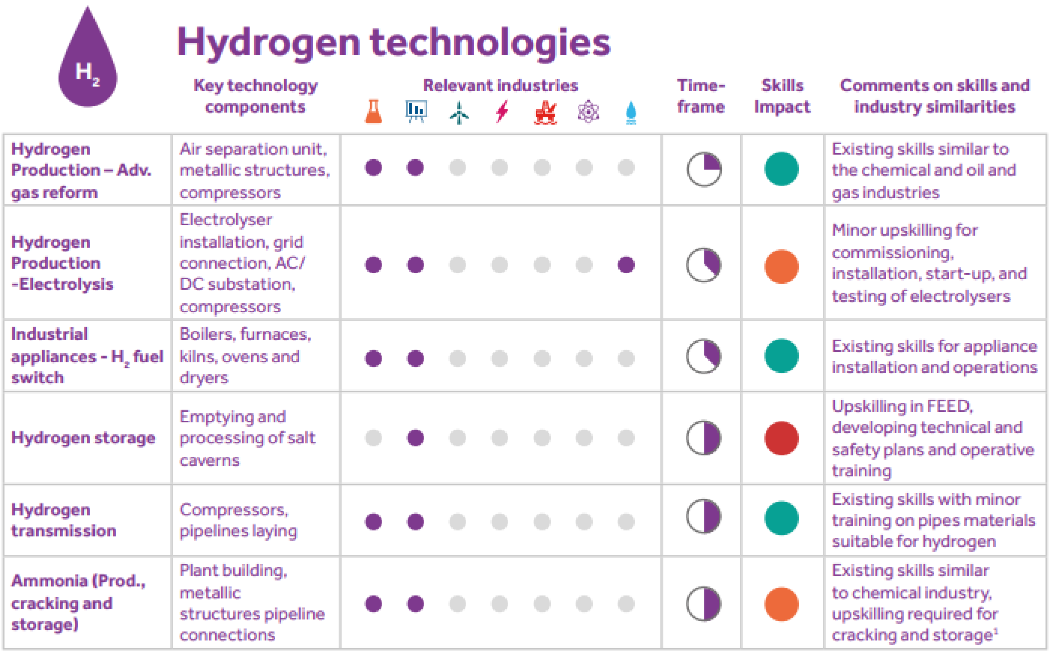
UK government suggests that the UK hydrogen sector could be worth over £900m and provide 9,000 jobs by 2030, with up to 100,000 by 2050[20]. This analysis includes the whole value chain of hydrogen – production, distribution, and storage. By 2050, 20-35% of the energy consumption could come in the form of hydrogen, hence this gas will play an important role in the UK energy strategy, it will change how and where the gas distribution network operates. The range of potential use cases of hydrogen in energy intensive industries will drive the demand from industry, which will consequently accelerate the change and lead to creation of thousands of jobs across hydrogen infrastructure.

Before a national hydrogen pipeline network becomes operational, other transportation options will need to be explored. If hydrogen is transported via trucks, it will create new jobs and require upskilling of current divers, with potential need for new certification. Distribution networks will require workers that have knowledge on how to safely operate work with hydrogen. Although some energy companies have workers with the appropriate skills, those people will likely need to be retrained and upskilled[21]. Given the future employment projections and the lack of appropriate skills on the market, there is a need to address it and create hydrogen related jobs across the value chain now. There is an opportunity to start tackling this challenge within distribution and end use of hydrogen at industrial sites as several demonstrations' trials are taking place in the UK. Companies can start mapping out and understanding the future needs and skills required. The right tools such as certifications, health and safety procedures need to be introduced and provided to build that talent pool.

Hydrogen related construction and installation equipment such as kilns, furnaces and burners are expected to be similar to today's technologies that are utilised for natural gas, which means limited disruption to respective workforce, however appropriate health and safety training (incl. related to hazardous gases under pressure) will be required.

[20] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1011283/UK-Hydrogen-Strategy_web.pdf

[21] https://www.ecitb.org.uk/wp-content/uploads/2020/03/Net-Zero-Report-Web.pdf



Hydrogen technologies

	Key technology components	Relevant industries	Time-frame	Skills Impact	Comments on skills and industry similarities
Hydrogen Production – Adv. gas reform	Air separation unit, metallic structures, compressors	● ● ○ ○ ○ ○ ○			Existing skills similar to the chemical and oil and gas industries
Hydrogen Production -Electrolysis	Electrolyser installation, grid connection, AC/DC substation, compressors	● ● ○ ○ ○ ○ ●			Minor upskilling for commissioning, installation, start-up, and testing of electrolysers
Industrial appliances - H_2 fuel switch	Boilers, furnaces, kilns, ovens and dryers	● ● ○ ○ ○ ○ ○			Existing skills for appliance installation and operations
Hydrogen storage	Emptying and processing of salt caverns	○ ● ○ ○ ○ ○ ○			Upskilling in FEED, developing technical and safety plans and operative training
Hydrogen transmission	Compressors, pipelines laying	● ● ○ ○ ○ ○ ○			Existing skills with minor training on pipes materials suitable for hydrogen
Ammonia (Prod., cracking and storage)	Plant building, metallic structures pipeline connections	● ● ○ ○ ○ ○ ○			Existing skills similar to chemical industry, upskilling required for cracking and storage[1]

Figure 7 Hydrogen technologies and skill impact potential [22].

4. Impact on UK economy and manufacturing

NNL's Nuclear Sector Deal Innovation report[23] from the round table on Hydrogen, begins by noting:

> *Hydrogen is a global commodity providing the UK with an opportunity to be the first mover in this internationally competitive market. A nuclear hydrogen industry represents a huge economic opportunity for the UK. However, nuclear will need to make a very strong environmental and financial case to ensure we capitalise on this opportunity. This needs to be done very quickly, at pace and should build on existing hydrogen infrastructure.*

It goes on to set out an action plan based on collaborative, cross sector response to 'enable nuclear energy to make a significant contribution to a world-leading hydrogen economy'. The plan proposes that the UK should:

- Rapidly embed a nuclear hydrogen economy now in the UK using existing nuclear, helping to 'build back better' and level up in the regions that need it most
- Enable accelerated development of future nuclear hydrogen systems using planned new nuclear build
- Deliver on net zero through providing reliable, high grade and low-cost clean hydrogen, making best use of new delivery models for economic success
- Position the UK as a 'first mover' for a nuclear hydrogen economy – maximising economic growth and regional prosperity.

By developing home grown technology, the UK can be self-sufficient, and develop skills and IP that can be exported to help the rest of the world in decarbonising its hydrogen and cement production.

4.1. Cement and Asphalt industry

The UK has a large industrial sector and significant portion of its greenhouse emissions come from this sector (c.15%). By using hydrogen to replace fossil fuels, the country can significantly decarbonise sectors such as cement, steel, asphalt, glass, mining, brick, and other energy intensive processes.

[22] https://www.ecitb.org.uk/wp-content/uploads/2020/03/Net-Zero-Report-Web.pdf

[23] https://www.nnl.co.uk/wp-content/uploads/2021/07/Hydrogen-Round-Table-FINAL-v2.pdf

The UK government has announced plans to invest in hydrogen production, storage and distribution, which could lead into creation of new job opportunities in research, development and manufacturing. In the sectors where hydrogen has not been yet introduced, its feasibility is likely to be proven, particularly in the cement and asphalt industry.

The replacement of fossil fuels with hydrogen in the UK manufacturing of cement and asphalt will likely have a positive effect on the industry as a whole. Hydrogen is a clean and sustainable energy source and does not produce greenhouse emissions when used as a fuel, which aligns and supports net zero by 2050 in the UK.

However, the transition to hydrogen fuel may also present challenges for manufacturers. The cost of green hydrogen and related equipment can be high, and the infrastructure to support hydrogen is currently limited. The implementation of hydrogen as a fuel in cement and asphalt manufacturing may initially lead to an increase in cost of production, and therefore, potentially resulting in higher prices for those products. However, as the technology for hydrogen production and storage improves, and the UK hydrogen economy at scale is achieved, the cost of hydrogen is expected to decrease, which could lead to a reduction in the premium price of foundation industries' products. Furthermore, the low-carbon credentials that hydrogen-based energy can bring to manufacturing processes and products could lead to a price premium. As more companies and customers become more aware of the benefits of hydrogen-based products they may be willing to pay a higher price for them. The impact of hydrogen implementation in those two sectors on premium price will depend on how quickly the cost of hydrogen can be reduced and how much the market is willing to pay for low carbon manufactured products.

The cement and asphalt industries are today witnessing demand for low-carbon products from their customers which presents both an opportunity and a risk. Decarbonising quickly may ensure these markets are not lost to competing businesses internationally, however this must be done in a way that does not negatively impact business as usual operations, nor at a cost that reduces the competitiveness of UK plc products. Hydrogen burner technology development for the asphalt industry is in its infancy. There is an opportunity for UK based companies to develop this technology ahead of the competition opening the doors for export opportunities. As part of the demonstration project, a burner manufacturer in Northern Ireland will pursue an R&D programme to develop this technology for use in the UK asphalt industry, potentially capturing relevant IP.

Hydrogen implementation in cement and asphalt sectors may require significant investment and changes to production processes – hence effort and time to make this transition happen is necessary. The right balance of speed and economics must be struck to ensure both success in decarbonisation and growth in UK industry.

Overall, the shift towards hydrogen as a fuel source is likely to bring long-terms benefits for the UK cement and asphalt manufacturing, including:

- Reduced carbon emissions
- Increased energy efficiency
- New job opportunities
- Upskilling

5. Societal considerations of siting of nuclear and other industrial facilities

Social considerations are also key in siting nuclear reactors and community engagement is essential throughout the planning and development process. While nuclear energy is amongst the safest form of energy generation in terms of mortality (equal to solar and wind) and over 600 times safer than oil,[24] public discussion often begins with concern.

Public engagement with the nuclear sector has had a long history. The West Cumbria Site Stakeholders Group (WCSSG), engaging communities around the Sellafield and Drigg Low Level Repository sites, can trace its history back over 50 years: "from the early days of the Windscale Local Liaison Committee to the Sellafield Local Liaison Committee. We remain absolutely committed to stakeholder engagement and see the WCSSG as an integral part of our communications strategy. Being part of this scrutiny forum, interacting with stakeholders on their concerns is fundamental to the open and transparent approach on which we have prided ourselves over many years."[25]

[24] https://ourworldindata.org/nuclear-energy#nuclear-and-renewables-are-far-far-safer-than-fossil-fuels

[25] https://wcssg.co.uk/about-us/

Similar stakeholder groups are facilitated by the Nuclear Decommissioning Authority (NDA) and its group of companies at other sites around the UK. Such communication helps to increase the transparency of the industry and the understanding of host communities to what work is undertaken, the processes involved and what hazard these present. For this reason, it is likely that communities local to current nuclear facilities are better informed than elsewhere in the country. At the same time, such communities are also usually more dependent on the nuclear sector and may be consequently more tolerant of any perceived or actual hazard it presents.

In 2021 BEIS undertook a public dialogue on advanced nuclear technologies[26]. This focused on communities chosen for their proximity to 'current nuclear infrastructure [1 of the 3] and other industries [2 of the 3]', with a sample designed to broadly reflect the UK population in age, gender, ethnicity, socio-economic group and rural / urban location.

The primary conclusion was that public engagement, following long-established learning in other nuclear operations, is essential in both the siting and the deployment of advanced nuclear facilities. It also notes that the responses were 'complex and nuanced'.

There were as well more specific findings that are key to the public discussion of nuclear as part of the solution to global warming. It was reported that: 'nuclear energy was an unexpected approach to net zero. Participants were generally surprised to learn that nuclear energy was low carbon. They had not seen it as part of the future energy mix or realised it could play a role in reaching net zero, and therefore this framing played a key role in shaping their views on nuclear energy throughout the dialogue.'

The final report providing the results of the dialogue stated 'Perceptions and experiences of current nuclear, and experiences of public involvement in decision-making generally, led to scepticism of the potential for genuine influence in policy-making and future decisions.' This finding was also borne out by Radiant Energy's 'Nuclear Confidence Survey'[27] which found that while 47% of respondents recognised nuclear as having a positive role as a climate change solution, this was 72/73% for solar and wind respectively. The Radiant Energy report does however, point to an increasing approval rating for nuclear and that this is in a good part due to its perception as a climate change solution.

These findings suggest that there is a considerable communication piece required and that that needs to start within the education system, with industry interaction. This should form part of the social value mission, with the understanding of the nature and uses along with the possible hazards associated with nuclear (as well as hydrogen and to a lesser degree cement and asphalt production) an essential pre-requisite to communities grasping and taking up the opportunities provided by it. The BEIS study has some important learning for the approach to communicating about nuclear with the public and communities:

"Perceptions and experiences of current nuclear, and experiences of public involvement in decision-making generally, led to scepticism of the potential for genuine influence in policy-making and future decisions. Participants considered transparent and meaningful involvement of the public and local communities essential in decisions about the use of advanced nuclear, as well as detailed decisions about where it is placed. Reflecting on their own pre-existing knowledge of nuclear technologies, some participants felt that educating the public on siting and deployment of advanced nuclear technologies (alongside other energy sources), was important. They emphasised that this should be impartial and balanced, focussed on enabling the public to question proposals for the future of energy in the UK, rather than to increase acceptance."[26]

Other significant factors in the improvement in public confidence in nuclear were its perceived reliability, but potential benefits to the local economies and job opportunities were significantly lower and the public understanding of the

[26] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1013681/advanced-nuclear-technologies-engagement-report.pdf

[27] https://www.radiantenergygroup.com/reports/state-of-nuclear-energy-support-in-the-uk-and-its-driving-forces

impact that any green energy source would have on energy bills was limited and therefore had little impact on the approval or otherwise of the energy source.

An important finding was that it is essential not to impose nuclear reactors on communities but to engage early to address concerns and provide a clear and transparent presentation of the facts about a next generation of nuclear and the needs it can meet. When this path is taken it suggests, there will be a less level of societal scepticism, better understanding and improved community relationships.

While the purpose of the work by BEIS was not to change people's perception of nuclear, during the study participants were asked weekly a question relating to support of nuclear energy. As shown in Figure 8, at the start of the work 24% of participants either supported or strongly supported nuclear energy for electricity generation, by the end this had increased to 56% showing that simple education and engagement can significantly help people understand and support nuclear energy.

From what you know, or have heard about using nuclear energy for generating electricity in the UK, do you support or oppose its use?

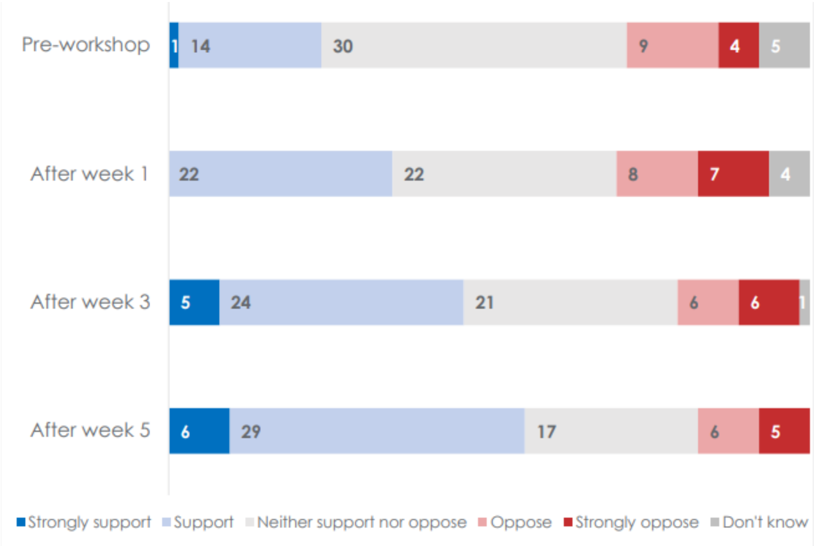


Figure 8 - Chart providing responses throughout the public dialogue on nuclear energy[26]

6. Carbon emissions saving potential

6.1. Steam Electrolyser - Cradle-to-gate analysis

Ceres, the developer of the Solid Oxide Electrolysis cell (SOEC), have worked with Ricardo to undertake a Life Cycle Assessment (LCA) of the environmental impact of the current fuel cell stacks.

As the stacks go on to be used in numerous different applications, this study covered the cradle-to-gate stage of the stacks' lifecycle, quantifying the potential carbon impacts associated with raw material extraction and processing, transport of materials to the Ceres manufacturing site, manufacturing of the unit by Ceres, and packaging of the unit, ready for distribution. The results of this study quantify the potential climate impact of producing the cells in terms of Global Warming Potential (GWP), a standard comparison of all product cycle gases to the equivalent carbon dioxide global warming impact and measured here in kilograms of carbon dioxide equivalent (kg CO_2e), for the current 5kW stack as shown in Table 2:

Table 2 – Equivalent kg CO2e to produce the current Ceres 5kW stack

Substage	5kW Stack (kg CO_2e)
Raw Materials	1148
Manufacturing	929
Transport	48
Total	2124
Total/kW	425

In 2021, Ceres increased its own manufacturing capacity to produce 3MW of stack technology, which if run continuously would displace over 4,500 tonnes of CO_2 a year. Ceres has signed agreements with partners aiming to scale up to 250MW of annual production of technology by 2024, with the potential to displace c.400,000 tonnes of CO_2 per annum compared to a conventional national grid energy mix in an average G20 country. We have a clear line of sight to the potential positive global impact of our technology.

Ceres recognise the importance of looking beyond carbon impact to consider the circular economy for raw materials. As a next step Ceres will undertake a full evaluation of the end-of-life recyclability or reuse of the technology, cradle to-grave, and will seek to lead the industry for their technology, embedding sustainability considerations into the very heart of development and the transfer of IP under licence to Ceres partners.

6.2. Cement and Asphalt

6.2.1. Cement

CO_2 emissions reduction is one of the most important objectives of the industry. Using 100% hydrogen in the kiln and calciner leads to total elimination of CO_2 emitted in the processing of the raw materials, leaving only emissions from the chemical reaction. Replacing natural gas with low-carbon hydrogen, which is considered a clean source of energy as it only emits water when burned, is a solution that brings significant reduction of carbon dioxide emissions as shown in Figure 9.

According to World Business Council for Sustainable Development, the amount of released CO_2 to produce clinker ranges from 0.73 to 0.99kg per kg of clinker[28]. Around 70% of CO_2 is liberated from the chemical reaction of $CaCO_3$ decomposition (approx. 0.5kg CO_2 for one kg of clinker produced as per study summarised in the table below) and it has to be separated and captured. Compared to the conventional fuel of coal, the hydrogen-based cement production shows a 44% CO_2 decline[29].

[28] https://www.tandfonline.com/doi/pdf/10.1080/20430779.2011.579357?src=getftr

[29] https://www.sciencedirect.com/science/article/pii/S1026918522000543#bib0028

Fuel	CO_2 emission (kg-CO_2 kg-clinker^{-1})		
	Calcination	Combustion	Total
Coal	0.51	0.44	0.95
NH_3/H_2	0.51	–	0.51

Figure 9- Comparison of CO_2 emissions from using coal and hydrogen in cement production

Hydrogen could be used as a fuel enhancer for harder to burn, high biomass content fuels. Across most, if not all, cement manufacturing sites globally, the part of the process where the hydrogen will be injected is susceptible to issues when burning lower grade fuels. Therefore, the use of hydrogen as a fuel enhancer could assist the production of low carbon cement in the UK and worldwide, without expensive replacement of capital equipment for unproven alternatives such as electric kilns.

Initial calculations indicate that with just a c.2% blend of H_2 by energy, the proportion of low-cost lower-carbon waste derived fuels increases (by c.5%) such that 6kgCO_2e per tonne of clinker can be saved, which equates to c.42kT annually from the UK cement industry based on 7m tonnes of production. Furthermore, just using hydrogen blends up to 30% by energy alongside coal, total emissions from the UK cement industry (6.28MT in 2021) could be reduced by c.565kT, a reduction of 9% per year, without considering the potential increase of waste derived fuels, which could make up the remaining fuel mix, potentially reducing cement combustion emissions to close to 0 (a c.1.7MT reduction per year nationally).

6.2.2. Asphalt

There are three main sources of CO_2 emissions associated with asphalt production:

1. Production emissions from burners, on-site mobile plants, and transport emissions
2. Emissions linked to electricity consumption
3. Emissions from purchased goods and services

For the calculations it was assumed that on-site mobile plants are minor emissions source and according to Hanson's publicly available information, on average direct emissions are approximately 25 kg per tonne of asphalt. The literature suggests that approximately 80% of the direct carbon emissions come from aggregate heating and asphalt heating, which is in line with Work Package 4 calculations that show 21.3 kg per tonne of asphalt. Additionally, in 2021 asphalt sales reached 28 million tonnes of asphalt. These data allow us to estimate the carbon emission saving potential if the asphalt plants switch fuel to low-carbon hydrogen.

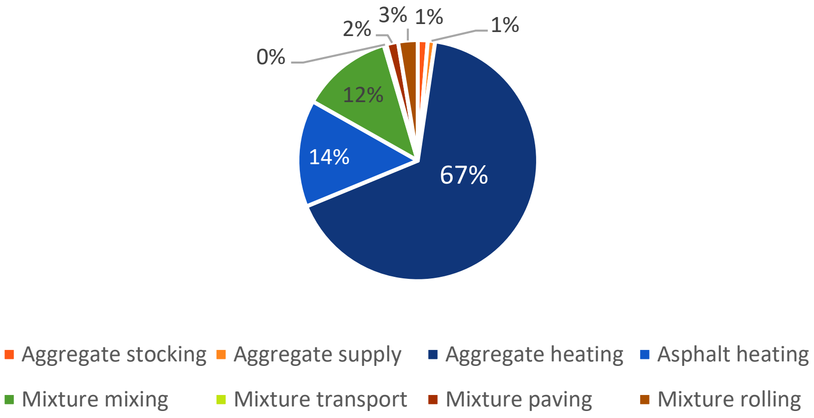


Figure 10 Proportion of carbon emission in each stage of asphalt production [30]

Dispersed sites in the UK contribute significantly to the country's carbon emissions. These sites release approximately 33.6 Mt CO_2e every year. However, by implementing hydrogen as an alternative fuel source, emissions from these dispersed sites can be significantly reduced. Calculations in Table 3 show that switching from fossil fuels, currently used in the asphalt production process, to hydrogen can lead to a reduction of 0.56 Mt of CO_2 emissions annually. Reducing emissions of dispersed sites by 1.6% could be a significant step towards achieving UK's ambition of fighting climate change.

Table 3- Comparison of emissions from fossil fuel and hydrogen production of asphalt

	Total direct emissions [tonne CO_2 /tonne of product]	**Aggregate and asphalt heating emissions [tonne CO_2 /tonne of product]**	**Estimated asphalt sales [tonnes]**	**Total CO_2 emissions [tonnes]**
Fossil Fuels	0.025	0.02	28,000,000	700,000
Hydrogen	0.005	0		140,000.0
			CO_2 savings	**560,000**

7. Knowledge Dissemination

Communication and dissemination are crucial elements in promoting the research undertaken to enable further progress in implementing hydrogen technologies and maximising project impact on future investments. Key dissemination activities for Bay Hydrogen Hub – Hydrogen4Hanson included LinkedIn posts, press release, internal presentations and a seminar organised by Institution of Mechanical Engineers, for the purpose of engaging with widest possible audience on several different communication platforms.

The project has met the following communication knowledge dissemination objectives through internal and external engagement:

- Promote the possibility of safe hydrogen production at the nuclear site
- Communicate and disseminate the project's activities, results and lessons learnt, including the valuable contribution of the DESNZ team and the need for initial and ongoing investment
- Promote awareness and confidence in the UK and worldwide on the benefits and challenges of nuclear hydrogen production
- Consolidate and make available all possible relevant public reports and results

[30] https://www.sciencedirect.com/science/article/pii/S2095756415000124

- Foster collaboration between all partners and UK stakeholders
- Share knowledge to consolidate existing expertise, refocus skills on nuclear derived hydrogen and its industrial implementation and grow interest in potential new workforce

The following activities have been undertaken to meet these objectives:

7.1. Activities undertaken

7.1.1. Press Release and LinkedIn Posts

At the start of the project Bay Hydrogen Hub Team collaborated with EDF Communications to publish a press release through the existing media channel of EDF LinkedIn and website. There were multiple positive comments, and the post reached a wide audience from oil & energy, utilities, construction, and renewable industry (classification defined by LinkedIn).

Table 4 - Press Release Engagement, November 2022

Impressions	Clicks*	Reactions	Comments	Shares
~62,200	~1,400	~1,000	25	35

*clicks refer to the website included in the post: https://www.gov.uk/government/publications/industrial-hydrogen-accelerator-programme-successful-projects/industrial-hydrogen-accelerator-programme-stream-2a-successful-projects--2#edf-energy-rd-uk-centre-ltd

7.1.2. EDF UK – internal dissemination

EDF R&D UK Centre has also carried out further Bay Hydrogen Hub project dissemination. Online presentation within EDF gathered a sizeable audience of approximately 300 EDF employees, received positive comments and was followed by Q&A session that proved topic being of interest internally.

7.1.3. NNL – press release stats

In the middle of November National Nuclear Laboratory (NNL) announced the project on their website and led to the news publication in New Civil Engineer, which is a monthly magazine for members of the Institution of Civil Engineers. The publication has reached the audience of nearly 500,000. Additionally, the NNL press release led to publication in World Nuclear News (WNN) and was among the most read articles as shown in Figure 11.

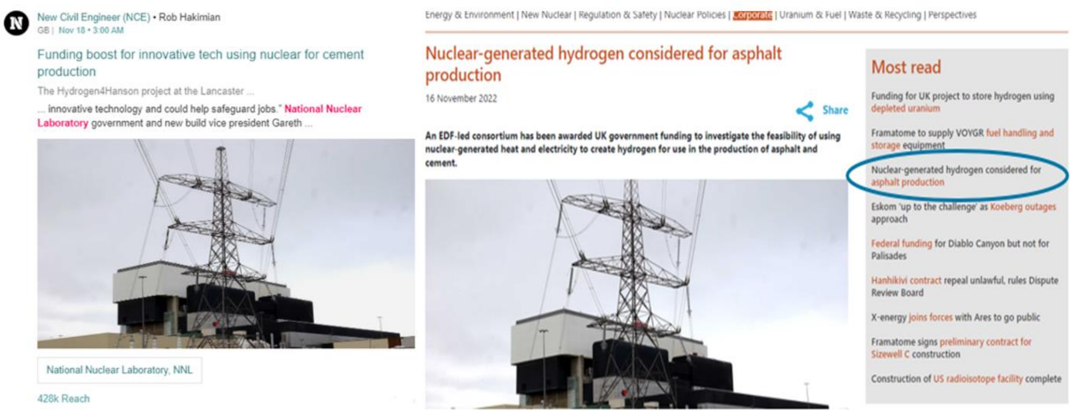


Figure 11- New Civil Engineer and World Nuclear News articles on Bay Hydrogen Hub

7.1.4. Industrial Hydrogen Accelerator (IHA) event

The Department for Energy Security and Net Zero (DESNZ) [previously BEIS], has organised the IHA Dissemination event to give the opportunity for all the projects that took part in the Stream 2A to share their findings. Bay Hydrogen Hub – Hydrogen4Hanson project team will give a brief presentation in the online event on the 24th of March 2023.

7.1.5. IMechE conference March 2023

Once the project final report is submitted, the Project Team plans to disseminate the findings at the Institution of Mechanical Engineers (IMechE) event “Engineering Challenges in the Hydrogen Economy” alongside other speakers on the topics of hydrogen production, storage, transmission, and use. This even is going to take place in London on the 14/15th March 2023 and dissemination is planned on the first date of the conference at 10:50 am as per agenda below, Figure 12.

A link website to find out more details of the planned event: [Engineering Challenges in the Hydrogen Economy 2023 | London (imeche.org)]

08:30 - Conference Programme

	Tuesday, 14 March 2023	
08:30	Registration and Refreshments	
09:00	Chair's Opening Remarks	
09:05 Keynote	**How the UK Government is Supporting the Hydrogen Economy** *Ian Graffy, Hydrogen Economy, Hydrogen and Industrial Carbon Capture Directorate, Department for Business, Energy and Industrial Strategy*	
	Hydrogen Generation and Supply	Storage Considerations
09:35	**Technology opportunities in hydrogen generation and supply** *Martyn Tulloch, Head of Energy System Integration, Net Zero Technology Centre*	**Overview of Hydrogen Storage in UK and Europe** *Stuart Doherty, Senior Process Engineer, Atkins* · Why is storage required and selecting appropriate storage options (e.g. underground vs. above ground storage considerations) · Overview of underground storage in UK and Europe · H2 storage end to end project considerations
10:00	**De-risking the hydrogen transition by considering Nuclear Enabled Hydrogen** *Allan Simpson, Technical Lead, Nuclear Enabled Hydrogen, National Nuclear Laboratory* · Technologies and their development status for Nuclear Enabled Hydrogen · Benefits of Nuclear Enabled Hydrogen and how this integrates with current UK policy · Challenges around the development and deployment of NEH	**Storage in Quaysides and Ports/Gaseous Storage Solutions** *Speaker to be announced*
10:25	**Large scale hydrogen considerations: supply from outside of the UK** *Speaker to be announced*	Pressure Systems **Pressure Vessel Testing - Current challenges in Sensing** *Ryan Marks, Applications Development Manager, MISTRAS Group*
10:50	**Hydrogen – from production to end-use** *Representation from EDF Energy*	**Challenges with Hydrogen Line Packing** *Grant Wilson, University of Birmingham*

Figure 12 Engineering Challenges in the Hydrogen Economy 2023 agenda