THE ROLE OF HYDROGEN AS AN ELECTRICITY SYSTEM ASSET
WP2/3 REPORT

April 2022

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Introduction
WP2 and WP3

SYNOPSIS

This report explores how hydrogen markets will develop under a range of scenarios, describing possible hydrogen transitions and system impacts.

The core aims are to:

- Research the long-term future hydrogen pathways and emerging thinking and ideas around hydrogen use.
- Consideration of hydrogen value chains, including changing customer demands, and locational factors.
- Reviewing and challenging FES scenarios based on the value chain analysis and a identification of a range of impacts that will lead to a shortlist being agreed with National Grid for further in-depth analysis

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Glossary of terms

AEM

Anion-Exchange Membrane

CCS

Carbon Capture & Storage

CCUS

Carbon Capture, Utilisation & Storage

CCGT

Combined Cycle Gas Turbine

OCGT

Open Cycle Gas Turbine

H2

Hydrogen

HGVs

Heavy Goods Vehicles

HRS

Hydrogen Refuelling Stations

LOHC

Liquid Organic Hydrogen Carrier

PEM

Polymer Electrolyte membrane

RE

Renewable Energy

SOEC

Solid Oxide Electrolyser Cell

SMR

Steam Methane Reformation

Stack

Part of the electrolyser that reacts with electricity to create hydrogen

TRL

Technology Readiness Level

Contents

Summary of overall Project Scope & Approach 1/2

DELTA-EE

Overall project scope:

To increase understanding of the future development of hydrogen markets and how targeted investment can more effectively support the electricity system

Project scope

- Outline possible future low carbon hydrogen landscapes under a range of scenarios
- Define interactions between the hydrogen vector and the electricity system operations and markets
- Identify the potential roles of hydrogen in supporting and optimising the electricity system
- Understand the opportunities for National Grid to best engage with the hydrogen sector across both the system and transmission parts of the business
- Assess how National Grid can best include the impacts of hydrogen in their forecasting and scenario planning including FES development and economic models

Outputs

- WP2/3: Final Report
- WP4: Final Report
- WP5: Final Report – including associated datasets, where applicable
- WP6: Final Summary Report
- WP8: Excel workbook/ Final Report

A six work-package approach

WP1 is mobilisation (complete)

This Report is for WP2 & WP3

- **WP2:** Identification of H2 value chains and pathways
- **WP3:** Analysis of H2 value chains and pathways
- **WP4:** Analysis of interactions between H2, National Grid, and the broader electricity system

Stage 1: Exploration (WP2–WP4)

- **WP5:** Impact analysis
- **WP6:** Summary Report

Stage 2: Analysis (WP5–WP6)

- **WP8:** Input to Redispatch Power2X development and data requirements

Stage 3: Support Redispatch (WP8)

WP7 is Project Management (ongoing)

Summary of overall Project Scope & Approach 2/2

Project approach

Stage 1: Exploration

An in-depth literature review, interviewing of industry experts and in-house modelling. This mixed methodology will be used to develop different use cases and value chains, which will then be long-listed and then short-listed.

Stage 2: Analysis

An in-depth analysis of the impacts of the short-listed value chains from stage 1. During the second stage of work, several topics will be explored in more detail. This analysis will provide evidence to inform the FES scenario development for 2022, and inform the assumptions and datasets used within the BID3 modelling to further develop the Hydrogen modelling capability. The nature and type of analysis conducted during stage 2 will include a range of quantitative and qualitative research.

Stage 3: Support Redispatch

Support National Grid on the Redispatch Power2X module development in WP8. We understand that the Redispatch module of BID3 will enable simulation of Hydrogen value chains. We will provide additional evidence to support the development of the Redispatch module.

1. **Short Run Marginal Costs** (SRMC) for Redispatch: This will be a logical output from the internal modelling we will be doing as part of the impact analysis for WP5.

2. **Bidders/multipliers** for Redispatch: We will use our hydrogen expertise and findings from within the project to work collaboratively with NG to propose possible bidders/multipliers ranges.

3. **Qualitative insight** for Dispatch/Redispatch: This will include assumptions around how and when the hydrogen market is likely to interact with the balancing mechanism. This will be an iterative process involving feedback from NG

Introduction and Scope

Aims for WP2 and WP3

Stage 1: Exploration – Strategic review of hydrogen pathways and scenarios

(WP2, 3 & 4)

Stage 1 provides an overview of how the hydrogen sector is likely to evolve under a range of scenarios. Additionally, this stage provides the next level of detail for the FES analysis, describing possible hydrogen transitions and system impacts. In WP2 & 3, this will include:

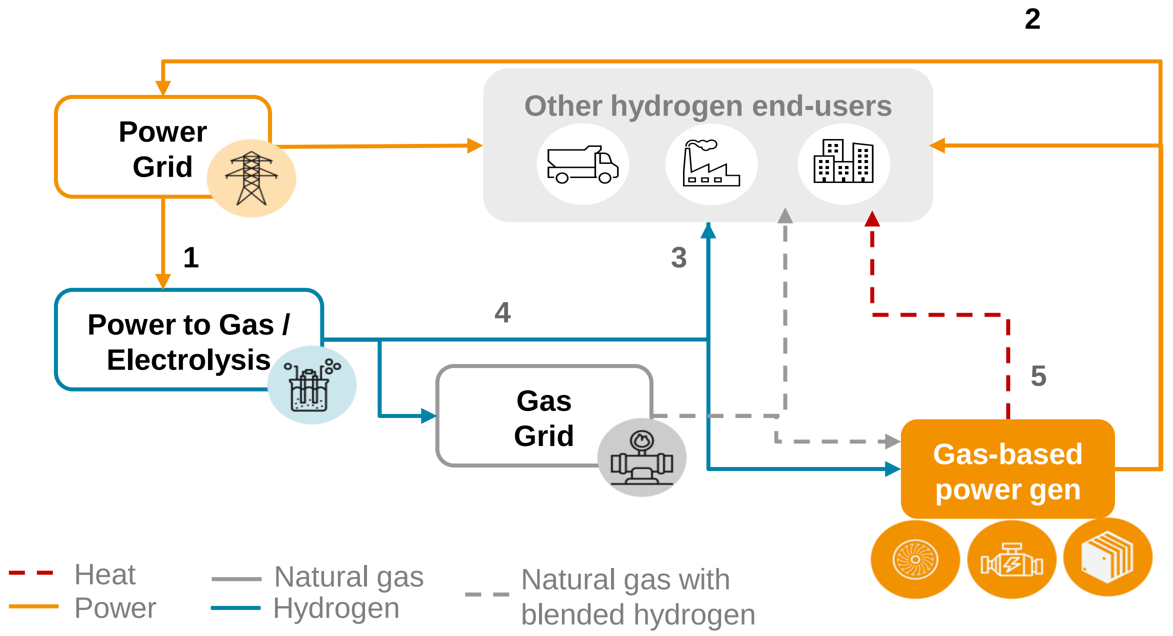
- Research into long-term future hydrogen pathways and scenarios drawing on current projects and FES scenarios assumptions, and emerging thinking and ideas around hydrogen use, and extensive stakeholder engagement.
- Considerations will include all elements of the hydrogen value chain (supply / generation, distribution, and end users), the role of storage, changing customer demands, and locational factors.
- A comprehensive list of hydrogen value chains will be produced.
- Reviewing and challenging FES scenarios based on the value chain analysis.
- A range of impacts will be identified and through working with National Grid a shortlist will be agreed for further in-depth analysis.

Executive Summary (1/3)
Overview

Emerging Hydrogen Markets

Efficient and cost-effective hydrogen for electricity network flexibility:

1. Electrolysers can provide demand-side flexibility.
2. Gas-fuelled generators can provide supply-side flexibility.
3. Multiple end-users will increase overall supply and demand for hydrogen.
4. Minimising hydrogen distribution costs through co-location and distribution networks.
5. Utilising both electrical and heat output can increase overall efficiency.

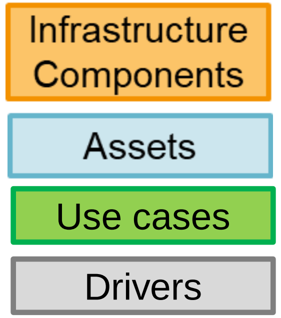


Defining the Value Chain Network

Use cases and value chains to assess the Hydrogen Market:

- different methods of hydrogen production.
- several options for storage, distribution and end-use.
- value chains consider the whole hydrogen market and allow for an infinite number of options to be considered.

Value chain components include:



Executive Summary (2/3)

WP2 - Key Findings from the Exploratory Stage

Literature review complemented with case studies focused on main variables within the Hydrogen market (production, storage, distribution and end-use).

Interviews with experts covered the following:

- Experts had varied opinions on blue and green hydrogen.
- Industry interviewees agreed that there were benefits to locating electrolysers close to their end-use, for example industrial heat, transport or close to renewables.
- They also agreed that electrolysers would eventually become multi-purpose assets. However, they were not united on timescales.
- Experts agreed that large storage infrastructure would be necessary for the hydrogen market development.
- Most of the interviewees believe that the hydrogen market will not replace or even be comparable to the gas network today.
- There was a divergence in opinion with regards to conversion of existing gas network to hydrogen and hydrogen blending.
- Industry stakeholders agree on the role of hydrogen to decarbonise various industries (e.g., high-temperature heat, direct-firing industries, and steel industry).

The hydrogen market is still growing. As a result, there are **multiple innovative technologies** still in development today. These include:

- Methane & Plastic Pyrolysis
- Solid Oxide Electrolysis Cell

Several key operation drivers were also identified.

- **Electrolyser use case considerations:** end-use for hydrogen generated, Balancing Market participation, source of power, co-location requirements, electrolyser maintenance costs.
- **Storage, distribution and end case considerations**: storage capacity, ways and distance of transporting hydrogen, storage co-location, peaking/baseload generation, etc.

Executive Summary (3/3)

WP3 - Key Findings from Developing the Value Chains and FES

Value Chain Progression

The Value Chains are constructed using **desk-based research** from WP2 and in-house **expert knowledge**.

The methodology produces an initial longlist of Value Chains (VCs) by assessing the key drivers of **Production, Distribution, Storage** and **End Use** assumptions across three scenarios:

- **Scenario 1**: Nationwide Hydrogen Transmission / Distribution network
- **Scenario 2**: No public Hydrogen network at any scale
- **Scenario 3**: Regional Hydrogen networks near industrial clusters

Scenario 3 represents a reduced hydrogen network, so there is crossover with VCs from both Scenario 1 and Scenario 2. The longlist from the 3 scenarios is first assessed for similarities and then **aggregated**.

The longlist is then analysed in-depth and mapped against FES. The **evaluation** and shortlisting includes:

- Use of interview data
- End user drivers
- Degree of electricity system interaction
- Timelines – short and long
- Confidence level

The **final shortlist** identifies key value chains which will be taken forward for impact analysis in WP4.

FES Assumptions Critique

Our hydrogen experts completed an appraisal of the current assumptions within the three most ambitious FES scenarios (CT, ST and LW) in relation to hydrogen. This resulted in a low/high confidence rating from Delta-EE of the following:

- Total hydrogen demand in FES
- Assumptions within three FES scenarios – including the following challenges:
  - CT – excluding non-networked electrolysis and BECCS
  - LW – excluding natural gas and pink hydrogen
- Comparison with total electrolysis capacity vs flexibility from electrolysis within FES

WP2: The Hydrogen Market and Defining Value Chains

Emerging Hydrogen Market 1/3

Hydrogen production methods for Net Zero

There are competing theories about how the hydrogen market will develop with several technologies at varying stages of development

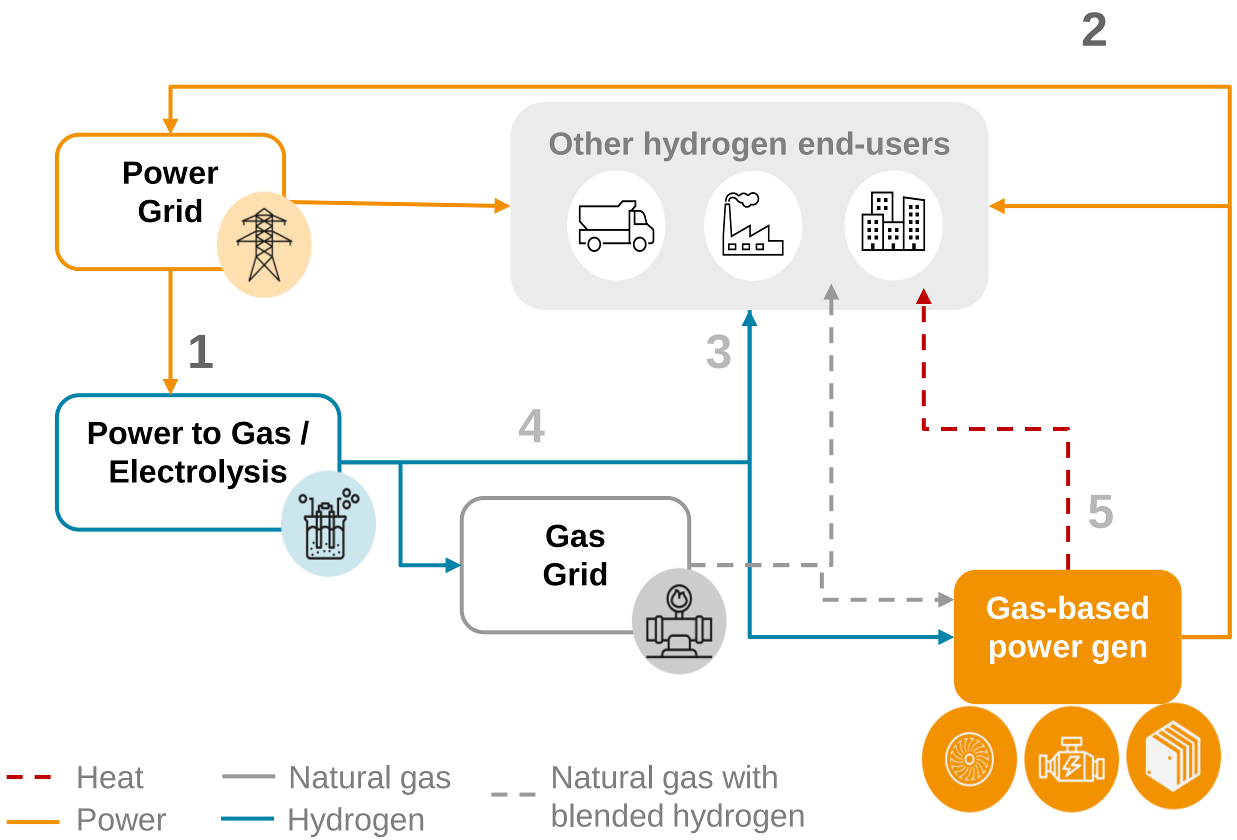
Type	Blue Hydrogen	Green Hydrogen	Pink Hydrogen	BECCS Hydrogen	New Technologies
Production Method	Produced through the **same process as grey hydrogen**, but utilising carbon capture and storage **(CCS).**	Produced via the **electrolysis of water** using electrolysers, powered by **renewable energy.**	Produced via the **electrolysis of water** using electrolysers, powered by **nuclear energy.**	Produced by **gasification or pyrolysis of biomass** at specialist facilities for the type of biomass used.	Potential for innovation from **new H2 production methods**. Many in development but at varied levels of TRL.
Advantages	Greatest **similarity to status quo** so that established processes/systems can continue.	Considered genuinely **carbon neutral**, has potential to reduce RE curtailment, inter-seasonal storage.	Steady supply of **carbon neutral electricity** while using waste heat. Alternative is reduced curtailment.	**Carbon negative** technology so can off-set carbon in harder to decarbonise areas.	Potential to be **cheaper** and with **high efficiencies.**
Disadvantages	Reliance on **natural gas** (energy security) and CCS (requires market to develop).	Market is currently immature (but developing) means production is more **expensive** than blue.	Requires **Solid Oxide electrolysers** which are new/developing technology. **PEM** may be better suited to RE co-location	**Expensive method** of production which is new/developing. Relies on CCS market (same as blue).	Currently at **differing levels of development** and may take **several years** before fully proven at scale.

Emerging Hydrogen Market 2/3

Hydrogen for electricity network flexibility

1. **Electrolysers can provide demand-side flexibility** to the grid, producing green hydrogen while helping to balance the electricity system. Electrolysers will be able to participate in balancing services.

2. **Gas-fuelled generators can provide supply-side flexibility** to the grid when additional generation is required. Currently natural gas is used but blending or pure hydrogen could be used in a similar way in the future.



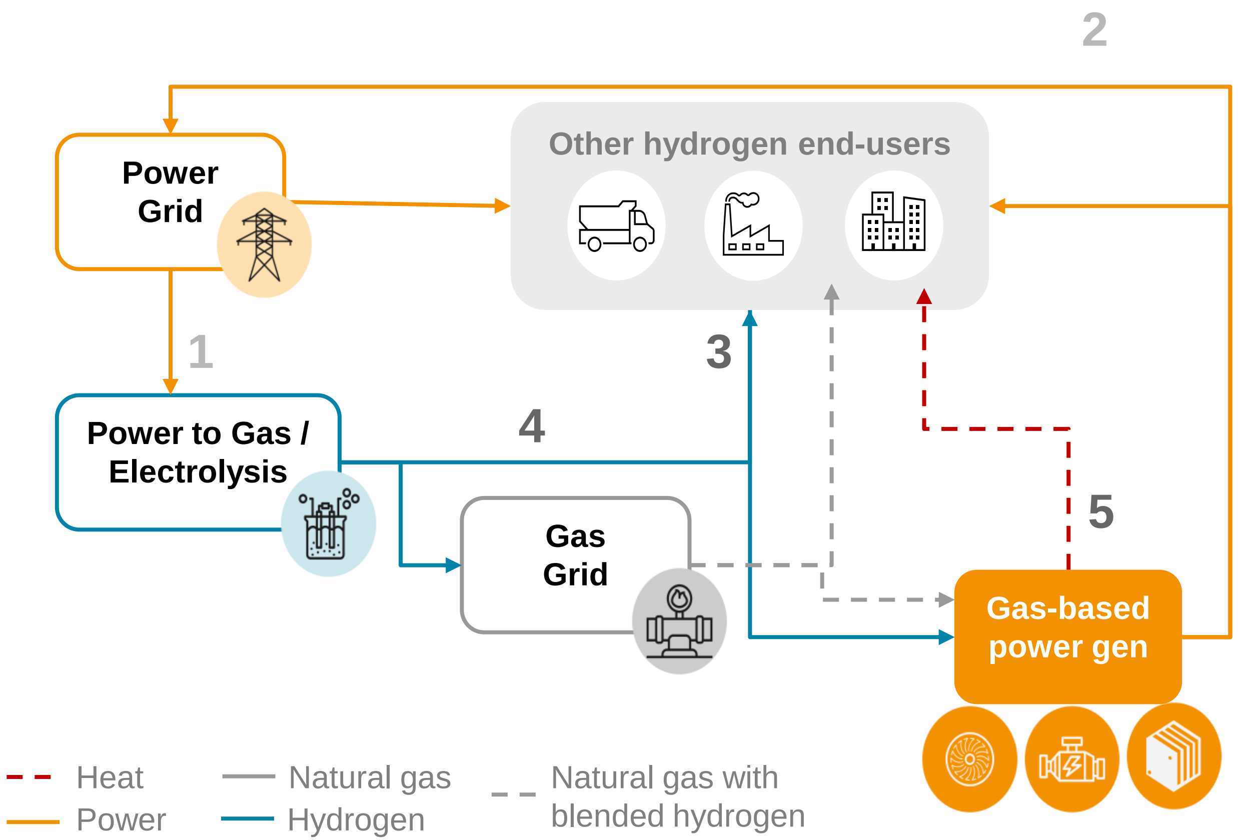
Emerging Hydrogen Market 3/3

Hydrogen for electricity network flexibility

3. **Multiple off takers will increase overall demand for hydrogen.** This will encourage total supply of hydrogen (which could be from a range of production methods) to increase.

4. **Minimising hydrogen distribution costs.** Co-locating hydrogen production and consumption (e.g., in an industrial cluster) can provide savings in the short-term. For longer distances, pipeline distribution offers potential savings compared to trucking hydrogen. Policy decision on gas networks not due until 2026.

5. **Utilising both electrical and heat output** has the potential to increase overall efficiency making the most of the hydrogen fuel for some end-uses. This could include, CHP or low-carbon heating, such as district heating schemes.



Defining the Value Chain Framework (1/2)

How to assess the emerging hydrogen market out to 2050

Use Cases and Value Chains to assess the Hydrogen Market

- **Different methods of hydrogen production** – decisions taken now will affect the path to Net Zero.
- **Several options for storage, distribution and end use of hydrogen** – The whole hydrogen market needs to be considered end-to-end rather than focusing on individual parts of hydrogen infrastructure in isolation.

Value chains consider the whole hydrogen market and allow for an infinite number of options to be considered. The value chains are then assessed for technical and financial feasibility.

Value Chain components

Assets – physical infrastructure or plant used within the Hydrogen market. Includes electrolysers, salt caverns, gas network pipes and gas engines

Use Cases – how assets are used, what is the business case for these. Potential for owners/managers to change/vary how they operate their assets in ways that can provide additional flexibility to the electricity network

Drivers – motivations to shift to a different use case (either short- or long-term). Includes potential payment for flexibility services, off-taking surplus energy generated, instead of curtailment.

Defining the Value Chain Framework (2/2)

Example Value Chain showing assets, use cases and drivers

Simple example

Desk-based research will be used to identify and quantify Assets.

In-house expert opinion will be used to refine potential Use Cases.

Industry expert interview data will determine the drivers which are largely assumption based.

	Production	Storage	Distribution	End Use
Assets	Electrolyser at renewable generator site	Pressure vessels	Road (no dedicated H2 network)	Power generation
Use cases	Used for curtailment prevention	Inter and intra day storage (co-located at peaking plant)	Road (trucking)	Peaking plants using hydrogen engines (or fuel cells)
Drivers	Generator invests in electrolyser – assumes profit for hydrogen higher than curtailment payments	Use determined by end use – power generation. Assumes viable business case for short-term H2 storage	H2 transported from production site to end use site – assumes lack of H2 network	Assumes high electricity prices meaning short-term use of H2 for power peaking is viable

Infrastructure Components

Assets

Use cases

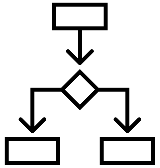
Drivers

WP2: Variables in the market - Hydrogen Production

Literature and Interview Findings

Variables in the Hydrogen Market: Production 1/6

Technical and operational ranges of assets



Hydrogen production using electrolysis

- **Types of technology**: Electrolysis - Alkaline and Polymer Electrolyte membrane (PEM) electrolysers are most commonly discussed in the literature as commercially ready.
- **Size/Capacity**: ranging from 10MW to 1000MW.
- **CAPEX:** $1000-1,750/kW (£745-£1,303)* for **PEM** (average) and $600-1,100/kW (£447-£819)* for **Alkaline** (average) - dependent on electrolyser capacity, etc.
- **Electrolyser Efficiency:** 72% efficiency for **PEM** (average) and 70% for **Alkaline** (average). Anticipate both electrolyser types will increase their efficiency rating to 80% up to 2050.
- Hydrogen **production costs vary** depending on the type of electrolyser used, power source (renewables, grid-connection, nuclear) and the utilisation rate of the electrolyser.
- Anticipate **increases in green hydrogen** production as the total amount of renewable energy increases, as there will be more opportunities.
- Government regulation/support could accelerate industry investments in new, low-carbon hydrogen generation.

(*converted on 31st January 2022)

Variables in the Hydrogen Market: Production 2/6

Input from industry stakeholders on electrolysers

Use Cases for Electrolysers

- Interviewees agreed that electrolysers would eventually become multi-purpose assets. However, they were not united on timescales.
  - **Single-purpose electrolyser** – an electrolyser that serves only one function: to produce hydrogen.
  - **Multi-purpose electrolyser** – an electrolyser site that serves multiple functions: hydrogen production, grid balancing services, reducing renewables curtailment, etc.

- Industry stakeholders had different opinions regarding single-purpose vs. multi-purpose assets:
  - Approximately half of the industry stakeholders stated that electrolysers would start as single-purpose assets, mostly due to the lack of attractiveness of flexibility business models. Investors usually refrain from these, as contracts are very short (2 years).
  - The other half stated that electrolysers would be used as multi-purpose assets early on, as the green hydrogen market would be more suitable for industrial clusters (those with on-site storage). One noted disadvantage is the large initial CAPEX requirements for multi-purpose assets.
- Experts agree that the business case for electrolysers to run only on constrained renewable power is not feasible at this point. The load factor would be too low (around 20-25%), and batteries would likely be more efficient (and less expensive) than an electrolyser.

Variables in the Hydrogen Market: Production 3/6

Input from industry stakeholders on electrolysers

Location of Electrolysers

- Industry experts agreed that electrolysers should be located close to their end-use, for example industrial heat (industrial clusters) or transport (HGVs and refuelling stations).
  - Co-locating hydrogen refuelling stations with electrolysers will reduce transport costs. The development of the hydrogen network throughout the country will further decrease transport costs.
- However, locating electrolysers with renewables (e.g., offshore wind farms) would utilise existing distribution infrastructure and be less challenging in terms of compression. Co-location with renewable energy plants would also avoid grid usage and balancing costs. Eventually, this would drive down the cost of hydrogen. But co-location with renewable plants is only feasible at scale with a hydrogen network.
- The hydrogen standard is likely to dictate the location of electrolysers and the type of power (from the grid or direct from renewable power plants) they use. The experts agreed that the ideal solution would involve flexible electrolyser location. The feasibility of this solution is to be determined.
- Stakeholders had different positions on the role played by hydrogen imports:
  - Hydrogen imports could start in the 2030s (in the form of ammonia or methanol), however, imports would be challenging to certify (green or blue).
  - Other stakeholders questioned the relevance of phasing out fossil fuels to replicate the same dependency on foreign countries for hydrogen – this does not improve supply chain resilience.
- Stakeholders noted that when co-locating electrolysers with renewables, stakeholders prefer using their own cables to supply electricity to the electrolysers instead of using the grid. To avoid this additional infrastructure investment, grid costs must be more reflective of system benefits.

Variables in the Hydrogen Market: Production 4/6

Input from industry stakeholders on hydrogen production

Blue and green hydrogen

- Three viable alternatives emerged out of our interviews:
  - Transitional use of blue hydrogen: used mostly in industrial cluster in the short-term, it will be phased out once demand and infrastructure have been established, and green hydrogen will replace blue. Green hydrogen would start ramping up in the 2030s.
  - Blue and green hydrogen develop at the same time: blue would be used for large-scale industries where demand is higher, and green in smaller industries where demand is much lower. Both green and blue hydrogen are needed to meet the 2030 5GW target.
  - Green will be deployed first starting in 2025: the fact that the production is still small and end-use can be co-located (or nearby) means a full gas network is not required in the short-term.
- Not all stakeholders interviewed agreed on the role of green hydrogen:
  - Some were unsure of its competitiveness in industry and feared it would drive companies to settle in other countries.
  - Others thought developing CCUS at scale would be challenging, and thus that not enough blue hydrogen would be available to meet the increasing demand.
- Blue and green hydrogen can’t be used in the same network as they have different levels of purity.

Variables in the Hydrogen Market: End Use 5/6

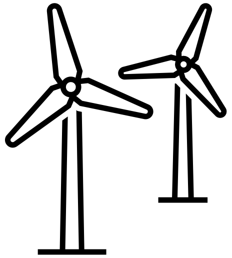
Input from stakeholder on Nuclear and Hydrogen

Pink hydrogen production

- There are 2 main options for hydrogen production when nuclear is the source of electricity:
  - **PEM electrolyser** – nuclear electricity powering the electrolyser – the key benefit being that when electricity generated by the plant would receive a relatively low price on the market, the electricity could instead be diverted to make hydrogen. There are minor benefits to the plant as it can operate as close to steady state as possible; this reduces maintenance costs and can increase plant lifetime.
  - **Solid Oxide Electrolyser Cell (SOEC)** – key advantage is using waste heat output from nuclear plants to supplement heat requirement of the SOEC. Both the SOEC and pairing them with nuclear plants are at early stages of development. But utilisation of the waste heat would increase electrolyser efficiency.
- **Thermochemical cycles technology** (emerging technology mentioned by nuclear expert):
  - Uses nuclear heat to produce hydrogen (instead of electricity). Creates possibility of dispatchable hydrogen supply without the requirement of electricity input.
  - Early stages of development and not yet operating. However, it is suitable for large-scale production.
  - Cost per unit of heat (OPEX) is generally higher, however, there are considerable benefits when it comes to CAPEX.
- Nuclear industry expert agrees on the role of hydrogen for industry, both for high-temperature heat and heavy-duty transport (HGVS).
- In terms of hydrogen use in domestic heating, there is consensus with other industry stakeholders.

Variables in the Hydrogen Market: Production 6/6

Key learnings from electrolyser case study



Case study: DOLPHYN - Deepwater Offshore Local Production of Hydrogen, UK – Offshore hydrogen production using offshore wind power

- DOLPHYN is a pilot project focusing on green hydrogen production at scale using offshore floating wind. The concept is currently at feasibility stage. Hydrogen is produced from seawater integrating PEM electrolysis and an offshore wind turbine on a floating sub-structure.
- Project Phase 1 & 2 – initial 'proof of concept' and further engineering designs for 2MW project, now complete. Phase 3 – further work and investment decision on 10MW project to be made in 2022.
- The project aims to demonstrate that vast offshore wind resources are suitable for hydrogen production – helps to mitigate a concern of limited renewable energy supply for green hydrogen production.
- Several prototype designs were considered initially:
  - *Dolphyn Concept*: hydrogen is produced with electrolysers on a deck area attached to the wind turbine (offshore) and transported onshore in a gas pipeline.
  - *Centralised Onshore Electrolysis*: hydrogen is produced in a centralised facility onshore. Electric cables link the offshore wind turbines to facility onshore.

Dolphyn Concept was selected, as it was deemed the most financially and technically viable design option. *Centralised Onshore Electrolysis* was considered the highest cost option, as the cabling is more cost-intensive than installing pipelines and the transmission of electricity requires additional substations.

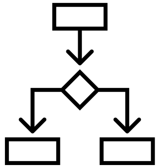
Key learning: It is more cost effective to **transport gas to shore** (via pipelines) than electricity (via cables).

WP2: Variables in the market - Hydrogen Storage & Distribution

Literature and Interview Findings

Variables in the Hydrogen Market: Storage/Distribution 1/6

Key considerations for hydrogen storage



Hydrogen storage and distribution

- Storage type: Linepack, compressed storage vessels, salt caverns, depleted gas/oil fields.
- For hydrogen to have a meaningful role in balancing supply and demand of electricity at a system level, considerable hydrogen storage capacities are required.
- Form of hydrogen: Hydrogen can be stored as pressurised gas, liquefied or carried by another component (ammonia, LOHCs).
- Storage efficiency: largely impacted by hydrogen form. Storing hydrogen in gas phase is inefficient and expensive (1kg of hydrogen requires large volume of around 11 m^3). Liquid form requires very low temperatures, which is energy intensive.
- Capacity of storage type: ranging from utility vehicles through gas pipeline networks to salt caverns and depleted gas fields.
- OPEX costs of storing hydrogen depends heavily on hydrogen form (gas, liquid) and storage type. Storage in salt caverns or depleted gas fields may require an extra step of purification before reaching its end use if blue hydrogen is stored. Storage in LOHCs requires an expensive transfer stage. Space and infrastructure costs associated with pressurised vessels are another example.
- Operational hazard due to a presence of pressurised hydrogen gas.

Variables in the Hydrogen Market: Storage/Distribution 2/6

Input from industry stakeholders on hydrogen storage and distribution

Hydrogen storage

- Interviewees agreed that salt caverns were the most suitable way of storing hydrogen over long periods of time. However, interviewees also agreed that building storage infrastructure to support a hydrogen market would come wit its own challenges. Mainly, due to the low volume of hydrogen currently available, salt caverns are not yet economically viable. Investors will be more interested in storage once hydrogen production increases, and there is more hydrogen to be stored. Storing large volumes of hydrogen is more economically viable, as it can substantially support the electricity system. There is a need for innovative business models that would make large-scale storage attractive to investors.
- Small-scale storage options (e.g., pressurised vessels) were mentioned only sporadically as they are less efficient in storing large amounts of hydrogen. Interviewees were uncertain on the likelihood and scale of using small-scale storage options for hydrogen:
  - Some thought that to compensate for the lack of salt caverns, operators could run localised storage sites in pressurised vessels as a short-term solution (2030s).
  - Others thought that localised storage in pressurised vessels was too small to have any real value.
- Overall, a vast majority of experts agreed that large storage infrastructure would be necessary for the hydrogen market to develop.

Variables in the Hydrogen Market: Storage/Distribution 3/6

Input from industry stakeholders on hydrogen storage and distribution

Hydrogen distribution

Most of the interviewees believe that the hydrogen market will not replace or even be comparable to the gas network today.

Isolated industrial hydrogen clusters would likely form close to electrolysers, feeding its end-use. Interviewees agreed clusters would appear in the North of England* and spread out geographically mainly towards the South and the West.

Where co-location of electrolyser and its end-use is impossible, a few ad-hoc, dedicated and relatively small hydrogen distribution networks could be used.

There was a difference in opinions with regards to interconnection of industrial clusters:

- Some said industrial clusters would be interconnected to maximise efficiency, and thus develop local distribution systems around them.
- Others described a system where hydrogen would only be used by industry, thus there would not be any local distribution.

* HyNet North West is a major industrial decarbonisation project aiming to provide low carbon power for industry, transport and low carbon heating for homes and businesses in the North West of England and North Wales. Through building and developing the infrastructure for low carbon hydrogen production, storage and transportation, but also blending hydrogen in to the gas network and capturing and storing CO2 emissions.

Variables in the Hydrogen Market: Storage/Distribution 4/6

Input from industry stakeholders on hydrogen storage and distribution

Hydrogen distribution

Two key questions remained on development of the system: Would the system follow demand, or will demand follow the system? Should a new demand sector be located close to an existing network, or should they wait for the network to come to them?

A few (3) interviewees support the conversion of the gas network. The main reasons for the conversion of the gas network were economic:

- the gas network enables more customers to demand hydrogen, allowing for more revenue
- the gas network is the cheapest hydrogen transport solution
- the gas network will become a stranded asset if it's not converted

Noteworthy reflections:

- Whether there is a network or not will determine the future use and location of electrolysers.
- The current gas network is not ready yet for carrying pure hydrogen. How can we convert it (several years project) while using a progressively increasing amount of hydrogen at the same time?
- How pure will the hydrogen be in a network? Are different streams needed or is there a way to maintain the same purity in a network supplied by different suppliers?

Variables in the Hydrogen Market: Storage/Distribution 5/6

Input from industry stakeholders on hydrogen storage and distribution

Hydrogen blending

Stakeholders had different positions on hydrogen blending:

- 20% of hydrogen in the gas network will not achieve UK targets for Net Zero, therefore blending is not a long-term solution.
- Blending (20% or more if possible) is a transitional measure to help scale-up the production and create a stable hydrogen demand.
- Blending (20%) will be done in the gas network, while pure hydrogen will develop in clusters by 2035. The gas network will not carry pure hydrogen.
- The gas network will carry pure hydrogen, while blending will happen at the end-use site, where needed.
- Industry stakeholders didn’t mention any certification issues: if blending gets approved, all appliances connected to the gas network will need to be able to safely operate with a blend of hydrogen.

Variables in the Hydrogen Market: Storage/Distribution 6/6

Key learnings from case studies

Case study: HyDeploy, UK – Hydrogen distribution via existing gas network

- Phase 1 of the project involved HyDeploy demonstration at Keele University.
- Phase 2: 668 residential and commercial properties to receive 20% hydrogen blend via the public gas network of the village of Winlaton for a period of 12 months starting in mid 2021.
- The appliances to receive the gas blend are mostly residential (boilers and cookers) with some commercial-sized boilers.
- Initially grey hydrogen will be supplied. It will then be replaced by green hydrogen from electrolysis.
- The primary aim of the trial is to overcome technical hurdles and gather evidence for a compelling safety case for hydrogen blending in existing gas networks, across different end-user and appliance types.
- The detailed market mechanisms are far from defined at this stage, but the networks are working closely with the UK Department for Business, Energy and Industrial Strategy (BEIS) to set the ground rules for a future market.

Key learnings:

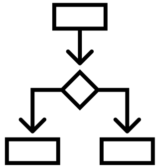
- The project-leading gas network operators are naturally seeing HyDeploy as a stepping stone for proving technical feasibility to establishing a broader hydrogen market for use in gas networks.
- WP3 will need to consider the role of gas networks and how this will affect Value Chains over time.

WP2: Variables in the market - Hydrogen End Use

Literature and Interview Findings

Variables in the Hydrogen Market: End Use 1/5

The technical and operational ranges of assets



Hydrogen utilisation

- Type of application: power source (for engines, turbines and power cells), in transport (vehicles, planes, ships and trains), in industry (as feedstock, for heat processes), heat and power for residential and commercial properties.
- Sector: power generation or non-power generation.
- Type of power technology: CCGT, OCGT, engine, fuel cell.
- Power size range:
  - <100MW
  - 100-1000MW
  - >1000MW
- Power type: peaking or base load.
- Hydrogen type suitability for end-use: blue vs green.
- Centralised or decentralised production feeding national or localised networks.
- UK government to decide in 2026 how significant a role (if any) hydrogen will have in residential heating.

(Source: Net Zero Strategy: Build Back Greener).

Variables in the Hydrogen Market: End Use 2/5

Input from industry stakeholders on hydrogen utilisation

Hydrogen utilisation

- Industry stakeholders agree on the role of hydrogen to decarbonise various industries (e.g., high-temperature heat, direct-firing industries, and steel industry).

- Most interviewees also agree on hydrogen's role in transport. Hydrogen will likely be used where electrification is difficult (e.g., HGVs, other large vehicles, trains, shipping and possibly aviation). There was a divergence in opinion on the timescale. Some stated hydrogen is already being used in transport, others said the rollout of hydrogen in transport will not occur until the ban on ICE vehicles in 2030.*
- Hydrogen can be used in transport under various forms. Industry stakeholders saw a role for methanol to be used in existing ships, while ammonia would be used for newer ships travelling over long distances. LOHC or cryogenic hydrogen could play a role in the future, although they are not available at scale at the moment.

- Interviewees seemed reluctant to give a precise answer on hydrogen for residential heating. Most predict some demand for residential heating, although they do not expect this before 2030. Another deciding factor is customer preference and policy decisions. For one interviewee, demand for hydrogen in domestic heating requires a full distribution grid conversion, which could be expensive.
  - Only one interviewee, in academia, gave us a precise answer on hydrogen for residential heating. They didn't foresee any demand for hydrogen in residential heating, and instead believed in the use of hydrogen in district heating applications.

*Delta-EE view: our EV team asserts that private and light good vehicles will largely be electrified in the run-up to 2030 so hydrogen will have minimal use. Our Hydrogen team recognises that some HGVs, bus fleets and industrial vehicles may use hydrogen in the UK.

Variables in the Hydrogen Market: End Use 3/5

Input from industry stakeholders on hydrogen utilisation

Hydrogen for power generation

- Most stakeholders agreed that hydrogen would be used for power generation, for two main reasons:
  - Hydrogen is better than battery for storage longevity.
  - Non-fossil fuel produced hydrogen power generation could be cheaper than using natural gas with carbon capture and storage.
- Stakeholders agreed hydrogen power generation would only occur after 2035, when storage and infrastructure to supply large volumes of clean hydrogen are established, and the power sector is fully decarbonised.
- Stakeholders had different views on the type of power generation most appropriate for hydrogen. This included:
  - Peaking and mid/large-scale generators (CCGTs) starting in 2026.
  - Peaking only and co-location with hydrogen production. The hydrogen produced would be stored for use in power generation later.
  - Lower peaking but only as last resort because of the high costs.
- Low rates of roundtrip efficiency were cited as a concern for hydrogen power generation hence the focus on peaking generation which commands high electricity price.

Variables in the Hydrogen Market: End Use 4/5

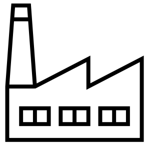
Input from industry stakeholders on hydrogen utilisation

Hydrogen for heating

- Industry experts believe blended hydrogen will play an important role in the initial stages of heat decarbonisation.
- Experts believe that industrial clusters will likely present the earliest opportunities to convert gas distribution network to hydrogen. The distribution network will likely be converted into pure hydrogen in nearby towns, supplying hydrogen for heating into homes. Joining of these clusters could eventually result in a nationwide network.
- Many experts across academia, regulatory bodies and industry believe that decarbonisation of heat is to be achieved via a **mixed approach**:
  - Electrification of heat seems to be more affordable and suitable for many of customers.
  - Pure hydrogen is likely to play a supplementary role to electrification of heat.
  - Hydrogen could play a specific role in:
    - Providing heating in specific locations where electrification is difficult or properties are more suitable for hydrogen.
    - Helping with the supply of electricity at times of higher heating-led electricity demand (e.g., winter or periods with insufficient wind/solar). Hydrogen is easy to store and can be stored for longer time than batteries, thereby providing a source of flexibility to generate power.
    - Localised hydrogen heating networks feeding off nearby industrial clusters, thereby reducing the overall demand on electricity network in that area.

Variables in the Hydrogen Market: End Use 5/5

Key learnings from case study



Case study: H&R Ölwerke (utilisation as a feedstock), Germany

- Green hydrogen produced on-site by one of the largest electrolysis facilities in Europe and used as a feedstock for petrochemical refining.
- PEM electrolyser capacity of 5MW with 500 tonnes of hydrogen produced per year.
- Additional benefits:
  - Minimising wind and solar curtailment.
  - Providing grid ancillary services.
- Initially, hydrogen was purchased from industrial suppliers and hauled to the site with trucks. Since 2017 it has been producing most of its hydrogen on-site using a PEM electrolyser.
- Only 18% of total costs were covered by public funds.

Key learnings: The right interplay of the electrolyser with the electricity system is critical to the commercial viability of the project. Ensuring hydrogen production at times when electricity is the cheapest is paramount.

WP2: Timing Issues and Key Operational Drivers

Timing Issues (1/4)

Changes over time and impacts of when these occur

The hydrogen market is still growing. As a result, there are **multiple innovative technologies** still in development today. This section introduces the emerging hydrogen production technologies that could impact the future hydrogen market out to 2050.

Other developments, such as the uptake of hydrogen demand, competition from other market players (batteries), availability of government funding, and the development of a full-scale hydrogen network will further impact the hydrogen market.

The TRL of each technology is assessed using the literature review against the following scale.

TRL9 Operations

TRL8 Active Commissioning

TRL7 Inactive Commissioning

TRL6 Large Scale

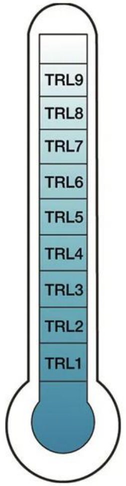
TRL5 Pilot Scale

TRL4 Bench Scale Research

TRL3 Proof of Concept

TRL2 Invention and Research

TRL1 Basic Principles



Source: https://www.gov.uk/government/news/guidance-on-technology-readiness-levels

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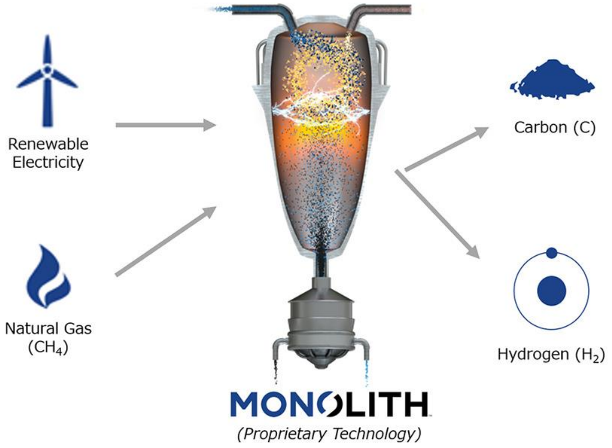
Timing Issues (2/4)

Emerging production technologies



TRL
8 (active commissioning)
Ready for commercial scale production

Methane Pyrolysis

- A novel way to produce **turquoise hydrogen**, which sits somewhere between blue and green hydrogen.
- Powered by electricity from renewable sources, natural gas is fed into a plasma furnace, where it is heated to high temperatures. Under these conditions strong methane bonds are broken resulting in two products: hydrogen gas and pure carbon.
- First commercial scale plant to come online in 2022 in the USA (Monolith).

Plastic Pyrolysis

- Plastic waste (polyethylene) is shredded so it can be converted to a synthetic gas using an advanced thermal conversion technology.
- The syngas is predominantly methane, which can be further processed into hydrogen
- Two facilities planned in the UK in Cheshire and Dunbartonshire using Powerhouse Energy technology.
- **TRL 8** (active commissioning). Ready for commercial operation.

Timing Issues (3/4)
Emerging production technologies

TRL 6 (large scale prototype)

A SOEC is a solid oxide fuel cell running on regenerative mode

- Operates on high-temperature electrolysis (500-850°C).
  - Easily powered by nuclear reactors for higher efficiency.
- Produces heat, oxygen and hydrogen. The heat produced can be recovered and reused to maximise efficiency.
- Benefits of coupling SOEC with nuclear plants:
  - No modification to the nuclear steam turbine cycle.
  - Flexibility of the nuclear power plant rises by 20% with almost constant thermal load of the reactor.
  - Produces pure, high-pressure hydrogen suitable for industrial purposes.

Application

- Ceres' 1-MW solid oxide electrolyser cell to be operational in 2022.
- First commercial SOEC stack in 2024.
- First commercial SOEC stack systems in 2025.

Source: https://www.ceres.tech/

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Timing Issues (4/4)

Emerging hydrogen production technologies

These technologies are currently in their infancy, but TRL could significantly progress in the next 10-20 years. They may have a role to play in total hydrogen production up to 2050, and beyond.

Technology	TRL	Production capacity	Real life applications	Key takeaways
Photo fermentation	5 (pilot scale)	1,3 tonnes/day of H2 2MW thermal power	HYVOLUTION plant	Integrated with dark fermentation.
Thermochemical cycles	4 (bench-scale research)	100 tonnes/day of H2 at EUR 2.79/kg	HYDROSOL, Horizon 2020	High efficiency using nuclear reactors for high-temperature heat and waste heat recovery.
Dark fermentation	4 (lab-scale reactors)	Unspecified at this stage, but generally low yields.	Applicable to wastewater from food and drink industry (e.g., dairy)	Produces impure hydrogen from locally-sourced organic waste.
Biological water-gas shift	3 (proof of concept)	Unspecified at this stage.	N/A	Complex microbial growth conditions limit industrial scale application.
Anion Exchange Membrane (AEM) Electrolyser	2-3 (invention and research)	500 NL/hour (using 0.4L water and 2.4 kWh electricity)	Enapter's modular electrolysers	Uses cheaper, non-platinum group metals. Produces high-purity hydrogen.

Key Operational Drivers (1/2)

Hydrogen production: electrolyser use case considerations

Key Question	Costs Impacted	Decision affected:
How will hydrogen be used?	CAPEX: Capacity requirements for use cases	Size of electrolyser selected and utilisation rate
Balancing Market participation	CAPEX: Capacity requirements – may need to oversize	Size of electrolyser selected and utilisation rate
Which source of power for electrolysers?	OPEX: cost of electricity highly dependent on source	Power source/location - electricity grid, renewables, nuclear
Will assets be co-located?	OPEX: Costs can be reduced by co-locating with storage, end user or the gas network	Electrolyser location
Electrolyser maintenance costs	OPEX: resilience – increased likelihood of wear and tear's impact on stack life	Electrolyser selected – may not be cost-effective to replace stack instead of upgrading whole electrolyser

Electricity Cost

Using either non-networked or curtailed renewable electricity (wind) for green hydrogen production will be cheaper than using grid in the run up to 2050. Therefore, developers may increasingly choose to co-locate their electrolysers with renewable energy to reduce OPEX costs.*

Stack and infrastructure lifetime

Current lifetime of stacks:

- AEM: 75,000 hours
- PEM: 60,000 hours
- SOEC: 20,000 hours

Estimated lifetime in 2050**:

- AEM: 125,000 hours
- PEM: 125,000 hours
- SOEC: 87,500 hours

*https://www.gov.uk/government/publications/hydrogen-production-costs-2021

** https://auroraer.com/insight/decarbonising-hydrogen-in-a-net-zero-economy/

Key Operational Drivers (2/2)

Hydrogen storage, distribution and end use case considerations

Key Question	Costs Impacted	Decision affected:
What is the storage size/capacity?	CAPEX/OPEX: Ability to obtain and maintain kit in global markets	Storage type
How will the hydrogen be transported to/from?	Distribution/OPEX: Cost impacts of transport type associated with each storage type	Storage type
What is co-located with storage?	Better business model/OPEX if co-located with Electrolyse or end user? Here, the gas network could be considered an end use.	Storage location
How will hydrogen be distributed?	Options will depend on policy and cost	Transport type
How far will hydrogen travel?	Options will depend on policy and cost	Transport type
How will hydrogen be used?	Options will depend on policy and cost	Type of power generation – will influence size
Is power generation peaking or baseload? Or both?	Options will depend on policy and cost	Size of plant

Regulatory changes: 2026 will determine if hydrogen is used for heating:

- This will inform infrastructure needs (network, electrolyser co-location).
- Use cases will also vary: after meeting the heating demand, will there be enough hydrogen for inter-seasonal storage?

End-user demand:

- Transport (HGV, aviation, shipping)
- Heating (domestic and commercial)
- Industry

Potentially competing hydrogen priorities:

- Long-term, inter-seasonal storage vs short-term supply to end-users
- Electricity production vs hydrogen exports

⇒ **Which of these is the most valuable at any given time?**

⇒ **How does value change throughout the day/month/year?**

WP3: Analysis of Hydrogen Value Chains and Pathways

A high-level analysis and building of a long list of value chains. This includes review and challenge of the existing FES narrative and assumptions. The final shortlist of value chains will then undergo an in-depth analysis.

Mapping Hydrogen Value Chains to FES

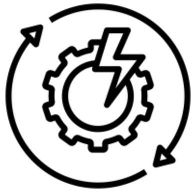
Propose new ways that Hydrogen could feature in FES

The icons below will feature on the Value Chain pages to show which value chains we think are of particular relevance to which FES

Consumer Transformation

Steady Progress

System Transformation



Leading the Way

Value Chain longlist: Methodology 1/2

Overview

Step 1: **Define overarching value chain groupings (scenarios)**

Value chains are grouped into scenarios that are based on critical infrastructure assumptions. National Grid's FES are used to inform and steer scenario development.

Step 2: **Specify 'fields' used to record value chains in Excel**

Characteristics (or 'fields') are specified and used to describe and record value chains. 'Fields' are grouped against value chain components; production through to end use.

Step 3: **Construct value chains**

Value chains are constructed within each of the overarching scenarios in Excel; driven by FES, the literature review, interviews and existing internal resources. Use cases defined in the VCs.

Step 4: **Test and refine value chains**

The value chains will be tested with research interviews, internal workshops and with National Grid ESO. This will also be a critical stage to test the drivers and rationales within the VCs.

Fixed assumptions across scenarios to 2050

- Hydrogen imports to the UK will be minimal, assuming the vast majority of demand will be produced domestically.
- Electricity output from nuclear power plants will remain broadly stable out to 2050.
- Biomass gasification will play a small role in hydrogen supply across all scenarios to offset emissions from Blue hydrogen production.
- The purity of hydrogen is considered equal across all production technologies and does not pose restrictions for different end uses.

Value Chain longlist: Methodology 2/2

Key drivers and assumptions across three scenarios

	Scenario 1: Nationwide hydrogen transmission and distribution network.	Scenario 2: No public hydrogen network at any scale.	Scenario 3: Regional hydrogen networks near industrial clusters.
Related FES scenario:	*System Transformation*	*Consumer Transformation*	*Leading the Way*
Summary:	**A national hydrogen distribution and transmission network exists by 2050. Hydrogen use for space heating is widespread.**	**No public hydrogen distribution or transmission network exist by 2050. Space heating in buildings is largely electrified.**	**Regional hydrogen networks exist by 2050, usually within zones around industrial clusters. Outside the zones heating in buildings is electrified.**

Value chain impacts:	▪ The presence of a national hydrogen network implies that hydrogen production, use and storage can be separated locationally.
	▪ Hydrogen producers and storers have much more flexibility in locating and sizing their assets, as they can rely on the gas network for offtake and distribution.
	▪ Value chains using decentralised electrolysis (such as small-scale electrolysis at a remote solar farm) become much more financially and logistically viable.
	▪ Large-scale storage will be required to buffer seasonal hydrogen supply swings. Shorter duration storage capacity can likely be lower, as it more easily be managed in linepack.
		▪ Centralised hydrogen producers are much more likely to co-locate their assets near demand centres, such as industrial clusters or large single industrial sites. This is because the absence of a gas network makes the gas distribution more costly and offtake riskier.
		▪ Where possible, demand centres will utilise large-scale geological assets for storage to buffer hydrogen supply swings. Otherwise, purpose-built infrastructure will be required.
		▪ Decentralised value chains are restricted to areas close to existing storage sites (e.g., electrolysis at a windfarm near an industrial cluster) or small-scale projects that utilise hydrogen on-site.
			▪ In this scenario, GB will be grouped into zones with and without hydrogen networks; value chains will develop according to zone.
			▪ Corresponding to **Scenario 1**, zones with a hydrogen network will see both centralised and decentralised value chains.
			▪ Regarding zones without a gas network (corresponding to **Scenario 2**):
			  ▪ any centralised hydrogen production will be limited to large single industrial or demand sites that sit outside of the clusters (e.g., airports)
			  ▪ any further production or use of hydrogen will be restricted to small-scale projects that utilise hydrogen on-site (e.g., refueling, power-to-gas-to-power).

Definitions

Decentralised value chain:

- Hydrogen production co-located with 1 single end-user.
- Projects often small-scale.

Centralised value chain:

- Hydrogen production for multiple end users, sometimes not located with end use (grid injected).
- Projects often large-scale.

Value Chain Scenarios (1/6)

Scenario 1: Nationwide Hydrogen Transmission / Distribution network

Production-led Value Chains

A range of methods for hydrogen production are considered, although the focus is green hydrogen.

Hydrogen is transported nationally through the gas network to any end-use.

Centralised Value Chains: Viable from today

Centralised green hydrogen powered **by off-shore wind power** located onshore. Used in industrial clusters nearby or ports which would require high-purity hydrogen.

Centralised green hydrogen which **avoids curtailment of large renewable** assets (onshore, offshore, solar). Hydrogen is either injected into the gas network or kept in large scale storage for industry.

Centralised **pink hydrogen for injection** into hydrogen networks (small scale). Includes both new and existing large scale nuclear sites, in isolated locations. Provides nuclear base-loading.

Viable value chains are transmission-connected with the potential to offer ancillary services. Benefits from co-location within industrial sites / clusters.

Centralised Value Chains: Viable from 2035-2050

Centralised marine electrolysis pipe hydrogen to shore from offshore wind (floating or fixed). **Serving many turbines.** Hydrogen enters gas network or large scale storage.

Centralised **nuclear thermochemical water splitting** for injection into hydrogen gas network (large scale). Advanced high temperature nuclear reactors for thermochemical water splitting. Dependent on technology readiness.

Value chains are expected to be large scale of 1000MW or more.

Decentralised Value Chains: Viable from 2035-2050

Decentralised green hydrogen for **curtailment mitigation**. Off-grid electrolysis as a competitor to batteries for renewable generation. Would inject hydrogen into gas network.

Decentralised green hydrogen for **constraint mitigation**. Electrolysis to avoid network reinforcement at interconnectors and other large assets. Would feed hydrogen into network or large scale storage.

Decentralised marine electrolysis pipe hydrogen to shore from offshore wind (floating or fixed). **Serving one wind asset.** Hydrogen enters gas network or large scale storage.

Value chains have an electrolyser utilisation rate of less than 50%.

Value Chain Scenarios (2/6)

Scenario 1: Nationwide Hydrogen Transmission / Distribution network

Storage-led and End-use-led Value Chains

A national hydrogen gas network facilitates both inter/intra-day storage and inter-seasonal storage.

The network enables electricity peaking to take place at both the local and national level.

Storage-led value chains : Viable from 2035-2050

Centralised inter-seasonal storage as a buffer for the network in peak demand (heating season and during doldrums). Since inter-seasonal storage will be linked to the gas network, generation could come from anywhere on the network.

Industry-owned and operated centralised inter-day and inter-seasonal storage buffer (network linked) for provision of green hydrogen to industry. Hydrogen production via an electrolyser with size of over 1000MW located at an industrial cluster.

Exporting or importing hydrogen into network and then inter-seasonal stores. Hydrogen likely produced elsewhere and imported into large geological storage.

Value chains are large-scale and use geological assets (e.g., salt caverns) which can include inter-seasonal storage.

Electricity generation-led value chains: Viable from 2035-2050

Localised peaking electricity generation on distribution networks (low MWs). Using hydrogen with OCGT, fuel cells or engines to mitigate local network issues.

National peaking electricity generation (high MWs). Using hydrogen with OCGT, fuel cells or engines to mitigate network issues. Includes ancillary services and balancing mechanism.

Peaking electricity generation (local or national) using imported hydrogen or carrier. If renewables are used elsewhere or not built fast enough.

Domestic heating using distribution networked hydrogen. Using hydrogen with OCGT, fuel cells or engines. Alleviates strain on networks while heating for homes by providing peaking and baseload power.

Unlikely to use hydrogen for baseload power, which means CCGTs will likely play a limited role in power generation.

End-use-led value chains (non-electricity generation):

Decentralised green hydrogen at HRS for isolated areas. Serving transport where hydrogen networks aren't available (small use case) using small storage. **Viable from today**.

Centralised green hydrogen owned and operated by large industry. Potential to replace blue hydrogen for industry but requires large storage to maintain industrial output and benefit from cheap electricity. **Viable from 2035-50**.

Centralised blue hydrogen production for industry provision and early hydrogen network injection. Initially for specific industrial use, as more users, plants and clusters come online, network injection into a hydrogen network develops. **Viable from today**.

Centralised blue hydrogen production for baseload production into national network. **Viable from 2035-50**.

Hydrogen end-use unaffected by hydrogen production method.

Value Chain Scenarios (3/6)

Scenario 2: No public Hydrogen network at any scale

Production-led Value Chains

Lack of a gas network means centralised value chains are favoured, with producers prioritising co-location of assets near end-users. These will be industrial clusters or large single industrial sites.

Decentralised value chains are restricted to areas close to existing storage sites or to small sites which are also hydrogen end-users.

Green Hydrogen Production Value Chains: Viable from today

Non-networked green hydrogen production for curtailment mitigation at renewable generation sites. Cannot provide ancillary services or grid constraint management.

Networked green hydrogen production for curtailment mitigation at renewable generation sites. Grid connection enables ancillary services and grid constraint management.

Green hydrogen production for use in transport. Distributed electrolysers co-located with refuelling stations / transport hubs.

Value chains use electrolysers that are small-mid range in size, most likely PEM.

Centralised Production Value Chains: Viable from 2035-2050

Green hydrogen production for **industrial use** in a cluster. Electrolysers will be operated to maximise hydrogen production.

Green hydrogen production for **power generation**. Medium-large scale generators, used for both baseload and peaking. Located near hydrogen supply, likely industrial clusters.

Green hydrogen production for **conversion to e-fuels** (aviation / shipping). Located at / near industrial site or cluster to minimise distribution costs. Industrial site could be located near major airport or seaport.

Continuous high demand for H2 within the clusters means electrolysers with a high utilisation rate that do not participate in balancing services.

Decentralised Production Value Chains: Viable from 2035-2050

Green hydrogen production at renewables site with re-electrification: **Power-to-gas-to-power**. Includes localised power peaking to mitigate distribution network issues. Assumes high electricity prices for viable business case and compensate round-trip conversion losses.

Green hydrogen for **curtailment mitigation / DSO constraint services**. Requires local storage and distribution. Covers use case of off-grid electrolysis as a competitor to batteries for small (MW) intermittent renewable generation.

Green hydrogen for **constraint mitigation**. Electrolysis as a means to avoid network reinforcement at interconnectors and other large assets .

Electrolysers outside of industrial clusters can provide balancing services and curtailment management. This is most likely a specific business case rather than as revenue stacking.

Value Chain Scenarios (4/6)

Scenario 2: No public Hydrogen network at any scale

Storage-led and End-use-led Value Chains

Storage will be co-located at either the production or end-use site, sometimes both. Hydrogen transport will be expensive and therefore limited.

Power generation using hydrogen is most likely within/near the clusters, where electrolysers will contribute.

Storage-led value chains: Viable from 2035-2050

Storage facility for industrial demand. Most will be green hydrogen with uncertain output; so storage capacity needs to be sized large enough to guarantee industrial demand is met.

Storage facility for baseload power generation demand. Larger generation assets will be located near demand centres with storage and production nearby.

Storage facility for peaking plants. Require steady, reliable hydrogen supply for short periods of time. Uncertainty of scale and timing needs to be factored into storage sizing.

Inter-seasonal storage. High power demand in winter will mean more hydrogen demand for baseload/peaking generation. Demand will partly be met by green hydrogen stored in the non-heating seasons; storage assets need to be sized accordingly.

Large scale storage with most value chains providing inter/intra day.

End-use-led value chains:

Decentralised green hydrogen co-located with HRS in isolated areas. Serving transport, small use case, using small-scale storage. **Viable from today**.

Small scale power generation for peaking. Generators are connected to the distribution grid. No gas grid means generators will co-locate their assets near hydrogen production, demand and storage centres; these are industrial clusters or large single industrial sites. **Viable from 2035-50**.

Medium to large scale power generation for peaking and mid-merit. Generators are connected to the transmission grid. No gas grid means generators will co-locate their assets near hydrogen production, demand and storage centres; these are industrial clusters or large single industrial sites. **Viable from 2035-50**.

Green H2 produced outside the clusters, will need to be co-located with renewable energy and will only be used for peaking plants.

Value Chain Scenarios (5/6)

Scenario 3: Regional Hydrogen networks near industrial clusters

GB will be grouped into zones with / without H2 gas networks; value chains will develop according to the zones.

Assets with access to a hydrogen network (i.e., a hydrogen zone) will have value chains corresponding to those found in Scenario 1. These will have very similar features and timelines:

Centralised hydrogen production: such as hydrogen production from both green and blue sources, to meet industrial, heat, power and transport demand in and around the clusters.

Decentralised hydrogen production: such as, electrolysis at renewable site for curtailment or localised peaking power generation.

Hydrogen storage: such as centralised inter-seasonal storage, industry-owned and operated storage and potential for hydrogen imports/exports.

Electricity generation end-use: focused on power peaking with value chains covering both local and national.

Other end-use: including HRS in isolated areas, injection into the gas grid, etc.

Value Chain Scenarios (6/6)

Scenario 3: Regional Hydrogen networks near industrial clusters

GB will be grouped into zones with / without H2 gas networks; value chains will develop according to the zones.

Assets without access to a hydrogen gas network will have value chains corresponding to those found in Scenario 2. These will have very similar features and timelines:

Centralised hydrogen production will be limited to large single industrial or demand sites that sit outside of the clusters (e.g., airports, ammonia plants).

Potential to use electrolysers for **curtailment mitigation** and **constraint mitigation**, although a lack of gas grid for hydrogen injection would make local, on-site storage a requirement of such sites.

Any additional production or end-use of hydrogen will be restricted to **small scale projects** (e.g., electrolysis at a small wind farm where tube trucking is viable) or projects that use hydrogen directly (e.g., refuelling stations, or Power-to-grid-to-power).

Aggregation, Evaluation and Shortlisting 1/2

Long-listing & In-depth analysis of key identified Value Chains

Aggregation: Several of the VCs constructed are **similar in terms of performance and drivers**. Differences between VCs have been assessed and where the level of difference is **deemed to be minimal**, the VCs have been aggregated.

Evaluation and Shortlisting

The methodology and thought process used for shortlisting does not represent a step-by-step process, but a cumulative approach of multiple considerations which involved prioritising some VCS and downgrading others. The aim is a shortlist of 8-10 Value Chains.

Use of interview data – While the interviews saw very little convergence of views regarding the future of hydrogen, there were some applications for hydrogen and factors within the market which deemed some VCs more likely than others. Delta-EE's hydrogen experts scrutinised VCs that were either not mentioned or directly challenged by interviewees and determined several that should be prioritised and others that should be downgraded as part of the short-listing.

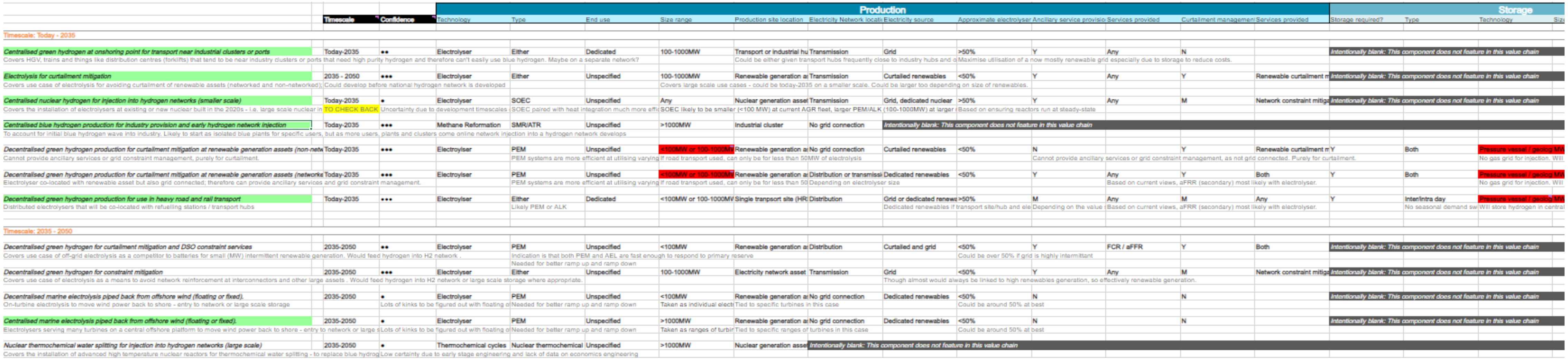
End user drivers – Using a 'start with the end' approach, a key assessment criteria involves consideration of the End-Use of hydrogen for each VC. Applications deemed least likely due to high levels of competition for hydrogen were downgraded.

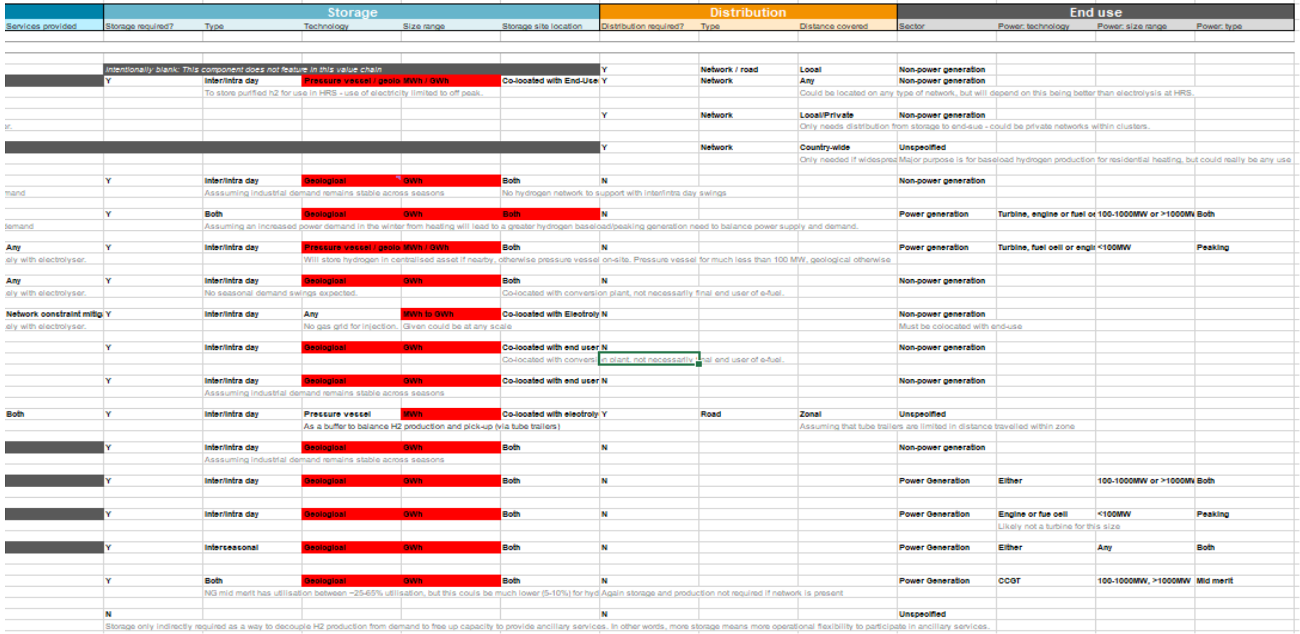
Degree of electricity system interaction – In accordance with the projects overarching goal, VCs deemed most likely to interact with the electricity system were prioritised e.g., ancillary services, DSO support, etc

Timelines – The VCs were divided into two categories; those that are likely to emerge in the near future (Today-2035) and those with longer timescales (2035-2050). VCs which include technologies or solutions that are more developed, such as PEM electrolysers were grouped in the near future category. Key assets deemed to require more time to be commercially ready were categorised as needing more time to develop. The team had a higher confidence in VCs with shorter timescales but ensured there was a balance between these and those with longer timescales.

Confidence level – In addition to rigorous consideration of the interview data, Delta-EE's hydrogen experts further challenged each others VCs based on a pre-scored confidence level. VCs with a low confidence rating were debated to determine the likelihood of hydrogen being economically competitive in such VCs. This let to a number of VCs being deemed less likely to come to fruition and therefore downgraded.

Aggregation, Evaluation and Shortlisting 2/2





Screenshots from the Excel document where the long-list of Value Chains are constructed, assessed, aggregated and short-listed.

Full documents provided to National Grid separately.

Results of Shortlisting 1/3

Final Short-list to progress for analysis in WP4

Value Chains determined for inclusion based on hydrogen expert analysis and dialogue with National Grid.

No.	Value Chain	Detail
VC1	Centralised blue hydrogen production for industry provision and early hydrogen network injection	To account for initial blue hydrogen wave into industry. Likely to start as isolated blue plants for specific users, but as more users, plants and clusters come online network injection into a hydrogen network develops.
VC2	Peaking electricity generation using hydrogen for peaking power (high MWs)	Turbine, FC or engine to help mitigate national network issues, ancillary services and balancing mechanism.
VC3	Mid-merit electricity generation using hydrogen	Longer term electricity generation using hydrogen CCGTs to fill the gap between base load (renewables) and peaking plants (OCGTS, engines etc)
VC4	Centralised nuclear hydrogen for injection into hydrogen networks (smaller scale)	Covers the installation of electrolysers at existing or new nuclear built in the 2020s - i.e. large scale nuclear in isolated locations. Helps provide nuclear base loading and provides hydrogen.
VC5	Electrolysis for curtailment mitigation	Covers use case of electrolysis for avoiding curtailment of renewable assets (networked and non-networked); curtailment may occur due to electricity supply/demand imbalances and network constraints.
VC6	Centralised green hydrogen at onshoring point for transport near industrial clusters or ports	Covers HGV, trains and uses like distribution centres (forklifts) that tend to be near industry clusters or ports that need high purity hydrogen and therefore can't easily use blue hydrogen.
VC7	Decentralised green hydrogen production for use in heavy road and rail transport	Distributed electrolysers that will be co-located with refuelling stations / transport hubs.
VC8	Electrolysis for frequency ancillary services	Electrolysers with the primary goal of providing grid balancing and where hydrogen production is secondary.
VC9	Hydrogen production from bioenergy with carbon capture and storage (BECCS)	For use in industrial applications. Expensive production method, but may be required to offset emissions from Blue production.
VC10	Centralised green hydrogen production for industrial use in a cluster	Hydrogen storage will be a key aspect for this value chain to decouple potentially intermittent hydrogen production from industrial output.
VC11	Centralised marine electrolysis	Piped back from offshore wind (floating or fixed).

Results of Shortlisting 2/3

Value Chain's excluded from Short-list

Value Chains determined not suitable for inclusion based on:

- **Strength of drivers for H2 end use**
- **Importance of VC attributed by Delta-EE and external experts**
- **Degree of electricity system interaction**

No.	Value Chains - Excluded	Selected reasons for exclusion
1.	Distributed peaking electricity generation on distribution networks (low MWs).	Was not included due to a lack of both maturity on current DSO focussed value streams and clarity on future DSO value streams and the low likelihood of this value chain being viable before 2035.
2.	Decentralised marine electrolysis piped back from offshore wind (floating or fixed).	Due to a lack of clarity and data on the specific format of marinised electrolysis that is likely to be exploited, there was little point in including two value chains with relatively minor differences.
3.	Nuclear thermochemical water splitting for injection into hydrogen networks (large scale).	The process is in the early stages of research, it would have a low number of electricity system interactions, very few of the experts canvassed mentioned the value chain and Delta-EE had low confidence in its relevance as a key value chain.
4.	Decentralised hydrogen purification for transport applications where blue dominated networks exist.	Very little confidence this could happen before 2035, coupled with minimal/uncertain effects on the electricity system and little mention or importance stated by experts.
5.	Decentralised green hydrogen production for conversion to e-fuels (aviation / shipping).	This VC was largely covered by green hydrogen for industry. H2 derived shipping and aviation fuel production is likely to have a similar demand profile (i.e. largely steady state) to petrochemicals ammonia for fertiliser but arguably has less end-use certainty than use as feedstock for currently mature processes.
6.	Large-scale blue hydrogen production for conversion to e-fuels (aviation / shipping).	Same arguments as the entry above with the added factor of having little direct impact to the electricity system (due to lack of electrolysis).
7.	Centralised blue hydrogen production for baseload hydrogen production into national network (i.e. to meet residential heat demand).	Has minimal direct electricity system interaction, was not considered an important VC by most experts (difficult from a efficiency and system transformation point of view), and little clarity of government direction for 100% H2 heat.

Results of Shortlisting 3/3

Value Chain's excluded from Short-list continued

Value Chains determined not suitable for inclusion based on:

- **Importance to FES 2021 scenarios**
- **Reasonable confidence that VC will be feasible before 2035**

No.	Value Chains - Excluded	Selected reasons for exclusion
8.	Domestic (SFH, MFH and DH) CHP (turbines, fuel cells, engines) using distributed networked hydrogen .	For minimal end-use drivers, little importance suggested by experts, little to no feasibility before 2035 and a lack of relevance to many FES 2021 scenarios.
9.	Decentralised green hydrogen production at renewable generation site with re-electrification (Power-to-gas-to-power).	For minimal end-use drivers, little importance suggested by experts, little to no feasibility before 2035 and a lack of confidence from Delta-EE on relevance.
10.	Network owned and operated centralised inter-seasonal storage as a buffer for the network in peak demand (heating season and during doldrums).	For minimal end-use drivers, little importance suggested by experts, little to no feasibility before 2035 and a lack of relevance to many FES 2021 scenarios. Also a lack of clarity over commercial roles and needs for this type of asset.
11.	Exporting or importing hydrogen into network and then inter-seasonal stores.	For minimal end-use drivers, little importance suggested by experts, little to no feasibility before 2035 and a lack of relevance to many FES 2021 scenarios.
12.	Peaking electricity generation using imported hydrogen or carrier (ammonia).	For minimal end-use drivers, little importance suggested by experts, little to no feasibility before 2035 and a lack of relevance to many FES 2021 scenarios.

WP3: FES Assumptions Critique

Challenge current FES assumptions within the context of our Value Chains

FES Assumptions Critique

Introduction

Approach

Delta-EE hydrogen experts **evaluated FES 2021**, including the datasets behind the various charts and tables within the report publicly provided by National Grid.

This was a **broad overview of the underlying assumptions** rather than a detailed analysis of the results. A high level comparison of the thinking behind the Value Chains and our expert knowledge of the sector is contrasted with the assumptions for the emerging hydrogen sector in FES 2021.

Key Findings and Recommendations

- **CT & ST**: FES may be underestimating the amount of power generation that could come from hydrogen by 2050
- **CT**: Relies on producing significant amounts of hydrogen solely or primarily from curtailed renewables. This may not be feasible in practice.
- **CT**: Recommend including non-networked electrolysis in this scenario as only networked is included currently.
- **CT**: Recommend including hydrogen supply from BECCs in this scenario.
- **LW**: Recommend including natural gas to produce hydrogen, at least initially. This could be phased out over time in this scenario.
- **LW**: Recommend including nuclear to produce hydrogen in this scenario.
- **All**: FES currently assumes that every GW of installed electrolyser capacity would be available for system flexibility. This is highly unlikely in practice.

Hydrogen Demand

Comparison of FES with Delta-EE low/high

Demand 2050 (TWh)	CT	ST	LW	SP	D-EE: low	D-EE: high	Comparable?
Industrial & Commercial	19	141	81	0	25	105	OK – similar order of magnitude
Road and Rail	32	62	45	2	19	84	OK – similar order of magnitude
Power Generation	2	1	22	0	12	25	D-EE assumes a higher base level of hydrogen demand for power generation in 2050

Conclusion: Only the LW scenario has a significant demand for hydrogen from power generation. The Delta-EE Value Chains include a greater focus on power generation, primarily to replace the role of gas power plants which support the electricity system with mid-merit and peaking power.

Hydrogen Supply Assumptions
Consumer Transformation Scenario

FES 2021 Assumption	D-EE confidence	Notes
The focus is on using renewable electricity to produce hydrogen, particularly when it would otherwise be curtailed.	Low	Question the feasibility of producing significant amounts of hydrogen from curtailed renewables alone (or primarily). Electrolysis developers would struggle with low utilisation rates and electricity supply uncertainty would be a challenge.
Non-networked electrolysers not included in this scenario.	Medium	As this scenario has the highest installed base of renewables capacity, it is plausible that a share will be dedicated solely to hydrogen production (i.e. non-networked). A more consistent electricity supply will ensure a steady hydrogen supply, which will be required for power generation applications, as well as for transport & industry.
Nuclear energy combined with electrolysis is introduced in the 2030s.	High	No concerns within this assumption.
No hydrogen supply from BECCs.	Medium	Nearly a quarter of hydrogen supply is coming from Blue sources in 2050. CT includes 12GW of electricity generation from BECCs, so there is potential some of this could be redirected into hydrogen generation.

Key Recommendations: Consider higher levels of hydrogen supply, from Blue or BECCS. Consider including dedicated non-networked electrolysis to meet transport/industrial demand.

Hydrogen Supply Assumptions

System Transformation Scenario

FES 2021 Assumption	D-EE confidence	Notes
Government support for hydrogen is strong from the mid-2020s so supply and demand grow quickly during the 2030s. Transition starts in the industrial clusters, where blue hydrogen is produced.	High	No concerns with this assumption.
No non-networked electrolysers appear in this scenario.	High	No concerns with this assumption. Given the abundance of Blue hydrogen within the scenario, and the relatively lower installed base of renewables capacity, dedicated non-networked electrolysis with renewables is unlikely to be required.
Almost 70% of hydrogen comes from steam methane reformation with green hydrogen, nuclear and biomass gasification providing additional volumes. The use of biomass with CCUS contributes almost 10% in 2050.	High	No concerns within this assumption. Given the scale and widespread use of hydrogen for heating and transport, a high proportion of Blue sourced hydrogen is very likely.

Key Recommendations: None, no concerns with the assumptions within the ST scenario.

Hydrogen Supply Assumptions
Leading the Way Scenario

FES 2021 Assumption	D-EE confidence	Notes
No natural gas used to produce hydrogen.	Low	The UK government has signalled its ‘twin track’ approach to low carbon hydrogen supply in the Hydrogen Strategy. Initial scale up of supply will occur in the late 2020s and early 2030s, likely to rely on Blue sources to meet industrial and transport demand.
The only scenario to include non-networked electricity generation.	High	No concerns within this assumption.
No nuclear used to produce hydrogen.	Medium	Scenario with the lowest installed nuclear capacity in 2050, but still >5GW. Nuclear plant operators will still want to operate as close to baseload as possible. Combined with a very high share of intermittent renewables, electrolysers would allow nuclear plant operators to produce hydrogen in times of oversupply / low electricity prices.

Key Recommendations: Consider including some hydrogen supply from nuclear.

Electricity System Flexibility Capacity from Electrolysis

Comparison with total electrolysis capacity

Total electrolysis capacity, grid-connected and nuclear-connected (GW)

	2050
Consumer Transformation	41.0
System Transformation	32.0
Leading the Way	57.9
Steady Progression	1.0

Electricity system flexibility capacity from electrolysis (GW)

	2050
Consumer Transformation	41.0
System Transformation	32.3
Leading the Way	57.9
Steady Progression	1.3

Consider:

- Is it plausible to assume that every GW of installed electrolyser capacity will be available for system flexibility?
- Slight discrepancy between flexibility capacity and electrolysis capacity in the ST and SP scenarios. How is the flexibility capacity higher?

FES Assumptions Critique

Conclusion

How Delta-EE will challenge FES assumptions in WP4

Challenge

1. **CT & ST**: FES may be underestimating the amount of hydrogen power generation
2. **CT**: Relies solely on networked electrolysis.
3. **CT**: Excludes BECCs.
4. **LW**: Excludes natural gas from the 2020s.
5. **LW**: Excludes pink hydrogen.
6. **All**: FES currently assumes that every GW of installed electrolyser capacity would be available for system flexibility. This is highly unlikely in practice.

Delta-EE Thinking at the end of WP2/3

1. Delta-EE Value Chains (VCs) include a **higher proportion of power generation from hydrogen**. VC2 (peaking) and VC3 (mid-merit) will be analysed in detail and which of the four FES they should be included in will be determined.
2. VC11 is a non-networked VC that produces hydrogen using dedicated renewable power. Our current analysis has not excluded VC11 from inclusion within the CT scenario as we have assumed **CT may include a private gas network**.
3. VC9 produces hydrogen from BECCS and assumes **generation is co-located with storage/end use** meaning no gas network is required. Similar to the above, our analysis to date has therefore not excluded VC9 from the CT scenario.
4. VC1 produces blue hydrogen in the early phases of the hydrogen market (today-2035). Our current analysis has not excluded this from any FES as it is likely **blue hydrogen will feature in the short-term**.
5. VC4 produces hydrogen from nuclear and assumes electrolysers will help **reduce turn down of the nuclear plant**. Our current analysis has therefore not excluded VC4 from the LW scenario as this would benefit the balancing of a Nuclear plant.
6. In WP4, Delta-EE will complete a high level appraisal of the 10 VCs to determine **how much electrolyser capacity could be made available for flexibility**.

Appendix

Datasets that have been uploaded by the Delta-EE team to National Grid's SharePoint

FES Research Matrix – v1: Excel document showing key data points from literature review in WP2

Contact Tracker: Excel document showing the list of organisations interviewed in WP2

Delta-EE_Value Chain Database (long list)-v2: Excel document of the final long list of VC's developed in WP3

National Grid Data Comparison_V1: Excel document showing comparison between key data points from FES with data from desk-based research – part of WP3