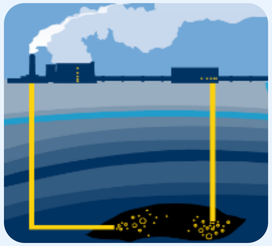

Hydrogen supply chain evidence base

Prepared by Element Energy Ltd for the

Department for Business, Energy & Industrial Strategy

November 2018

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Contents

Objective: creation of a dataset to support analytical and modelling work

Formation of a dataset to support heat decarbonisation analysis

- Element Energy were contracted to lead the creation of a dataset to support analytical and modelling work around estimating the cost and emissions of hydrogen's potential role in heat decarbonisation.
- The dataset covers the cost and performance of the individual components of all aspects of a potential hydrogen network conversion, from production through to end use, namely:
  1. Hydrogen generation
  2. Hydrogen storage
  3. Carbon Capture and Storage (CCS)
  4. Transmission pipeline
  5. Distribution network
  6. End use technologies
- The assumptions that have been collated for this evidence base are based on the best available evidence at the time (the majority of the assumptions were collated in 2017 and the methane reformation assumptions were reviewed in late 2018). There are clearly huge challenges in making accurate estimates into the future given the large number of unknown factors and for a system that would require such large infrastructure change. The significant uncertainty in these estimates and assumptions should not be overlooked.

Peer / Industry Review

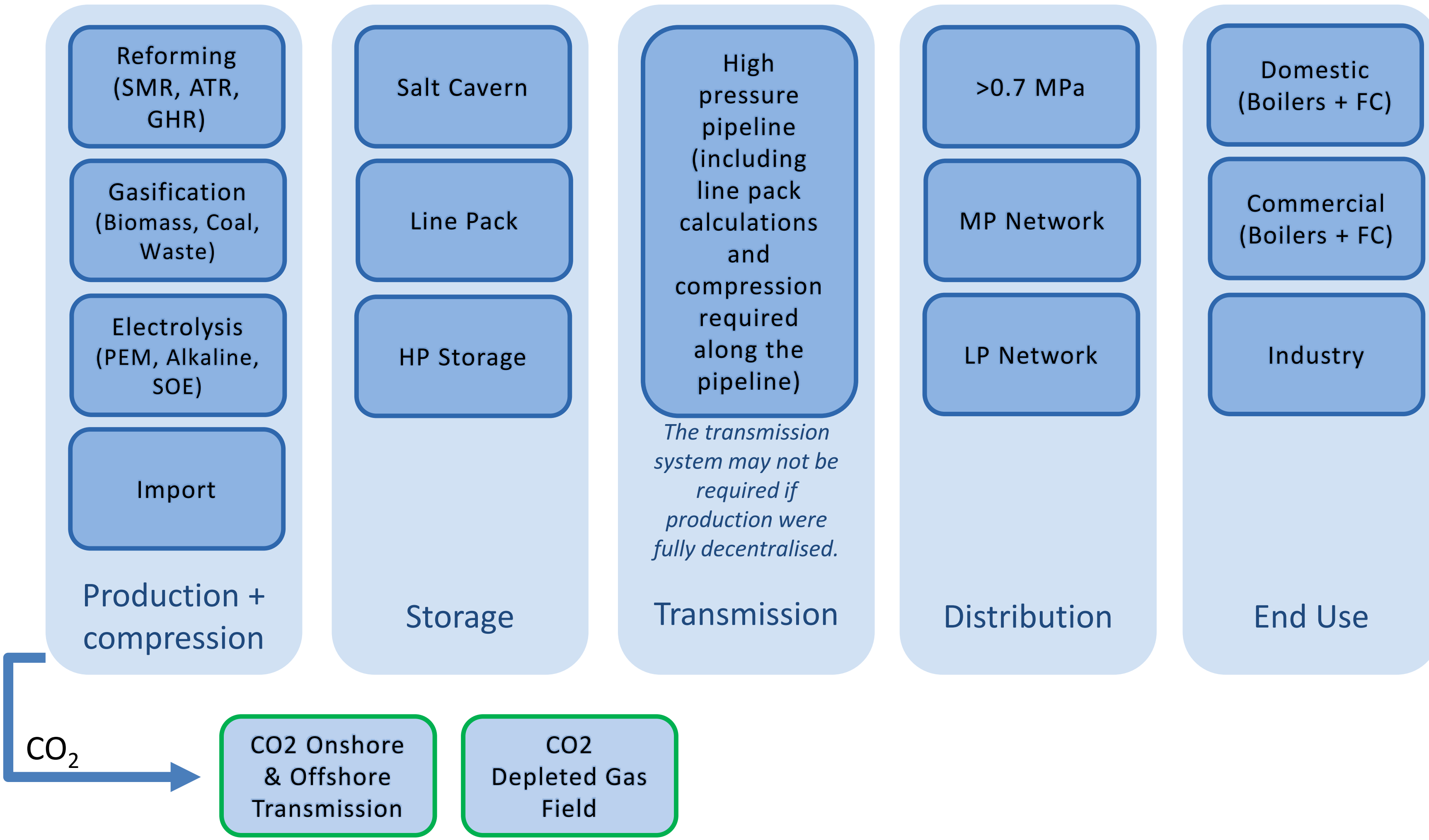
External review of data

- The data in an earlier draft version of this slide pack was sent to a number of organisations / associations for peer review.
- The feedback from the review was, where appropriate, incorporated into this document and the accompanying dataset.
- The membership of the following organisations/associations were contacted:

  - Energy Networks Association (ENA)
  - Carbon Capture and Storage Association (CCSA)
  - UK Hydrogen and Fuel Cells Association (UKHFCA)
  - Scottish Hydrogen and Fuel Cells Association (SHFCA)
  - Hot Water and Heating Industry Council (HHIC)
  - Institute of Gas Engineers and Managers (IGEM)
  - Fuel Cell and Hydrogen Joint Undertaking (FCHJU)
  - Hydrogen Europe
  - Energy Technologies Institute (ETI)
  - Energy Systems Catapult (ESC)
  - Committee on Climate Change (CCC)
  - The Institution of Engineering and Technology (IET)
  - Decarbonised Gas Alliance (DGA)
  - Hydrogen and fuel cell research hub (H2FC)
  - UK Energy Research Council (UKERC)
  - Sustainable Gas Institute (SGI)
  - Institution of Chemical Engineers (IChemE)
  - Institution of Mechanical Engineers (IMechE)
  - UKCCSR

The main elements of the hydrogen for heat supply chain are shown schematically in the diagram below

Network schematic



- Overview of the project
- **Hydrogen Production**
- Transmission
- Distribution
- End Use
- Storage
- CCS

Hydrogen Production

Three main production technologies have been included in the dataset. They are selected based on technology which is available today and which have relatively predictable cost evolution curves. These include:

- Electrolysis (PEM (Proton Exchange Membrane), Alkaline and SOE* (Solid Oxide Electrolyser))
- Steam methane reforming
- Gasification (of various feedstocks)

In addition, liquefied hydrogen could be imported by ship (discussed later in this report).

Production plants typically output in the range from 1 to 4 MPa depending on the technology selected. Depending on the transmission pipeline pressure selected, they may then require compression to enable injection into the Transmission network. Therefore compression data is also included within the Hydrogen Production section.

To avoid any confusion, please note that Electrolyser data is quoted in kWh electricity input per kg produced (as this is the figure recognised in industry), whilst all other data is provided in terms of kWh H2 HHV.

** - Although not available commercially it is included due to the potential of the technology at large scale, once mature*

- **Hydrogen Production**
  - **Hydrogen Purity**
  - Electrolysis
  - Reforming
  - Gasification
  - Liquid hydrogen import
  - Compression

Hydrogen Purity – Approach adopted

An approach to hydrogen purity

The purity of hydrogen output from the different production techniques will vary. In particular for the hydrocarbon based production options, an increased requirement for purity can increase capital and operating costs. More specifically:

- Electrolysis – can be relatively easily configured to meet automotive grade hydrogen 99.999% purity levels
- Methane reformation – will produce limited quantities of contaminants, in particular carbon monoxide, which can cause issues for fuel cell systems as well as potentially causing health issues (in large concentrations) – this requires purification via either pressure swing or membrane based purifiers
- Gasification – similar to reformers, with a wider range of potential contaminants due to the more diverse feedstock
- Import – via liquefaction would lead to a very pure hydrogen stream due to the distillation effect on liquefaction.

Discussions with reformer experts at Jacobs suggest that the 99.8% purity specification as defined in the H21 report is manageable without a significant impact on the capital and operating cost of the reformer plants.

This is therefore used as the minimum purity specification for all systems.

A higher specification is deemed excessive given the additional impurities which would likely be picked up from contaminants already within the pipelines.

Where distribution pipework is repurposed for hydrogen there is likely to be contaminants leaching out from the walls of the pipelines, including sulphur based odorants.

Hydrogen Purity – Specification

Definition of the hydrogen purity specification

- A hydrogen for heat transmission / distribution system will require the creation and definition of a dedicated hydrogen purity specification.
- Whilst for this analytical work **we have defined a specification of 99.8%** a formal specification would need to clearly define the maximum permissible impurities permitted.
- In practice the specification should be defined in legislation (analogous to the Gas Safety (Management) Regulations 1996 – GSMR), this would be derived based on the minimum requirements of the gas shippers and end uses on the network.
- In conjunction with the end use technology development **a full cost benefit analysis** will be needed to assess the optimum specification to give the minimum cost basis for production and end use (end to end cost optimisation).
- To create the purity specification a bottom up approach must be taken working from end use back up to production.
  - Currently Fuel Cells (used in transport) are requiring 99.999% purity with very strict and very low permitted contaminates (ISO 14687) – *It is extremely unlikely this purity could be maintained through transmission so Fuel Cell applications will require a lower specification or purification pre-use.*
  - The Giacomini catalytic boiler purity requirement is 99.5% (source: Leeds H21 report)
  - Combustion (no catalysts) would not require a high purity though there are higher NOx emissions in the absence of a catalyst. If a catalyst is needed for NOx control, this may create additional purity issues.
- H21 adopted a hydrogen purity of 99.8%
- The KIWA/E4Tech "DECC Desk study on the development of a hydrogen-fired appliance supply chain"[1] questioned whether the purity should be 99.5% or 99.99% or 99.999%.

(1)https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/537594/30686_Final_Report_DECC_Hydrogen_appliances_08.07.16.pdf

- **Hydrogen Production**
  - Hydrogen Purity
  - **Electrolysis**
  - Reforming
  - Gasification
  - Liquid hydrogen import
  - Compression

Hydrogen Production – Electrolysers (PEM)

PEM Electrolysers

Hydrogen electrolysis with PEM (Proton Exchange Membrane) offers rapid dispatchability and turn down to follow the energy output from renewables and is therefore ideal for pairing with wind farms for low-carbon hydrogen production or the provision of rapid response to the grid.

There is good data on PEM efficiency and cost predictions from a European study commissioned by the Fuel Cell and Hydrogen Joint Undertaking (FCH JU) in 2013 (1). Additionally, data can be found in the US H2A study in 2012 (2), as well as results from field trials.

Element Energy have assessed the data and applied engineering knowledge to produce a predicted base case for the analytical work using current knowledge applied to previous studies. Ranges are included to reflect upper and lower bound assumption on the rate of technology progress.

The cost and efficiency of a PEM electrolyser includes:

- The electrolyser system
- All necessary balance of plant (drier, cooling, de-oxo equipment, de-ionisation)
- Civil works for the electrolyser (building + foundations)
- Grid connection

Pressure:

Typical output pressure is 2 – 3 MPa, but work is underway to attempt to increase this to >8 MPa to allow for direct injection into transmission systems.

We assume 3 MPa for the base case, with an increase to 8 MPa for the best case electrolyser. This means a compression step will be represented for the base case electrolyser but not required for the best case.

Water consumption: 20 litres of potable (but not de-ionised) water per kg of hydrogen is assumed (0.51 litres potable water per kWh H2 HHV)

(1) Development of Water Electrolysis in the European Union - http://www.fch.europa.eu/sites/default/files/study%20electrolyser_0-Logos_0_0.pdf
(2) US Department of Energy - http://www.hydrogen.energy.gov/h2a_analysis.html

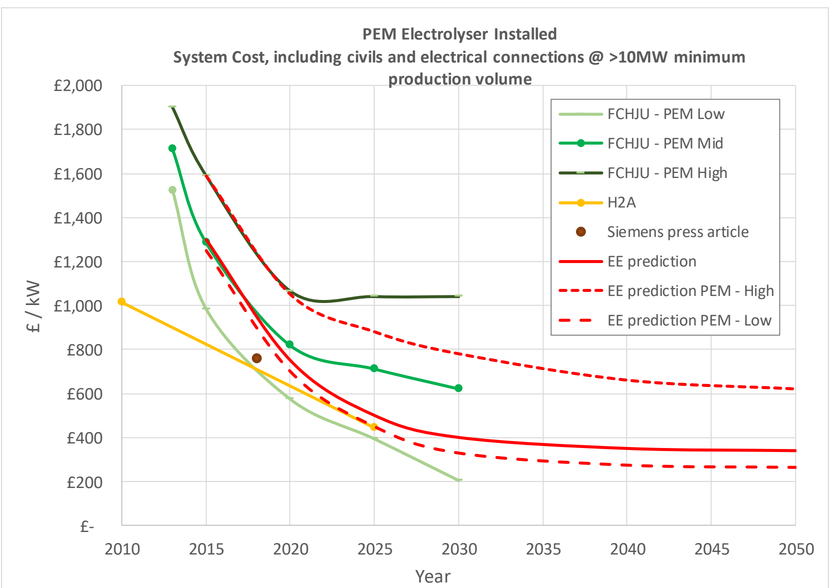
Hydrogen Production – Electrolysers (PEM)

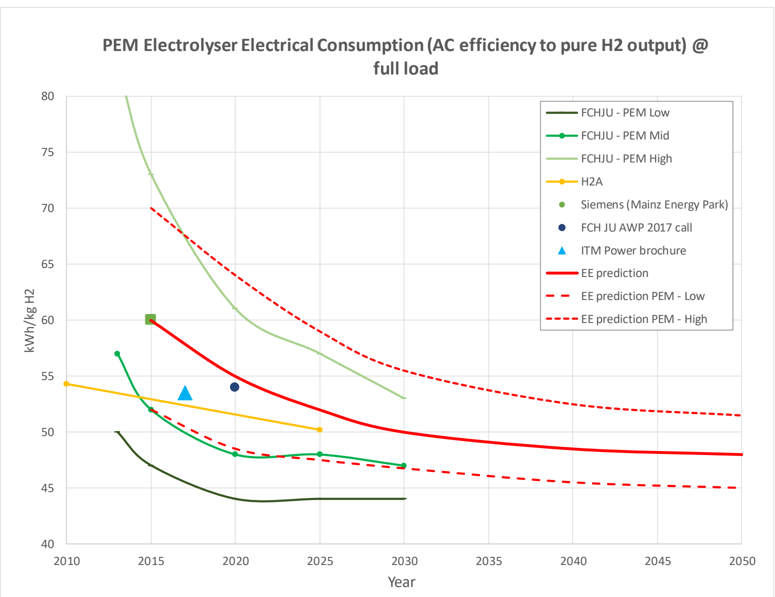
PEM Electrolysers

Core assumptions are plotted below – For the central case, we assume (based on current trends) that manufacturers will favour price over efficiency initially, though through time (once costs come down), technology improvements can be taken as efficiency by reducing current densities.

Numerous manufacturers are already quoting <€1,000/kW (electrical input) installed costs for 2020 systems at scale, suggesting the mid case for costs can be easily achieved and potentially be exceeded.

Based on discussions with suppliers, the FCH JU efficiency lower bound projections look very ambitious. The FCH JU mid case is considered to be the more realistic lower bound energy efficiency projection. Note that kW in electrolyser data is kW electrical input in common with all industry data.





https://www.siemens.com/innovation/en/home/pictures-of-the-future/energy-and-efficiency/smart-grids-and-energy-storage-electrolyzers-energy-storage-for-the-future.html
http://www.energiepark-mainz.de/en/project/energiepark/
http://www.itm-power.com/product/hgas

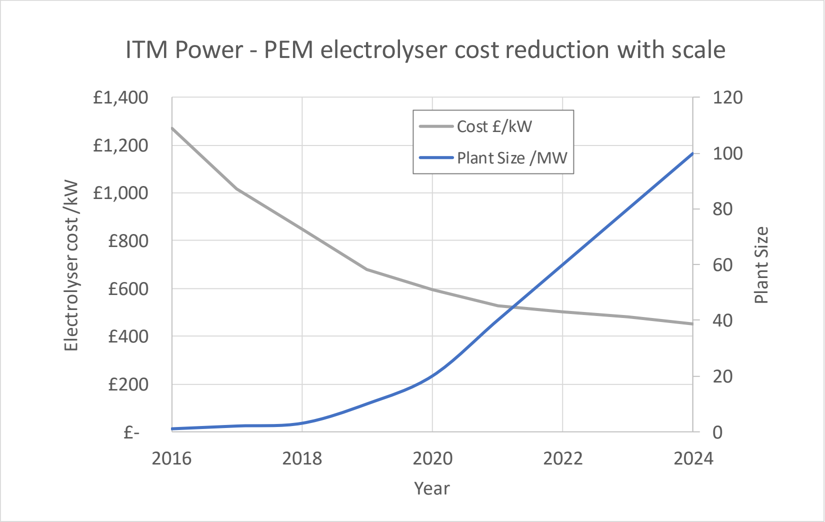
Hydrogen Production - Electrolysers (PEM)

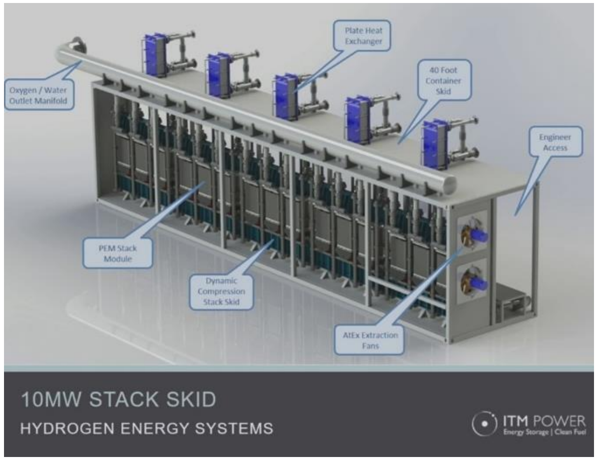
PEM Electrolysers – Additional effect of scale

There are two impacts as a result of scale:

- Size of individual plant: the larger plants have a lower fixed cost per kW of output and benefit from other economies of scale
- Total number of plants deployed: the cumulative number of electrolyser plants will have an impact on cost as a result of learning rates

The graph to the right shows ITM Power's prediction for cost versus size of deployment with time. The approach taken by most manufactures is to create a module around 5-10MW in size and replicate this to build up to 10's or 100's MW (electrical energy input)





The modular approach gives a relatively low cost benefit for scaling individual installations, and we see the larger cost savings coming from the total number of installations rather than size of individual installations.

The main reference for an electrolyser learning rate suggests **7% cost reduction per doubling** in installed capacity[1]. This learning rate would be international as they are manufactured by a small group of Global suppliers.

For PEM electrolysers the total installed capacity is currently less than 50MW.

(1) - Hydrogen TINA – Carbon Trust 2013

Hydrogen Production – Electrolysers (Alkaline)

Alkaline Electrolysis

Hydrogen production by alkaline electrolysis is a proven technology with almost 90 years of operational experience. The largest plant to date is rated at 90MW (electrical energy input) [currently mothballed] and produced around 1,200 kg H_2 / hr for ammonia fertiliser production.

A European study commissioned by the Fuel Cell and Hydrogen Joint Undertaking in 2013 (1) gives good data on alkaline efficiency and cost predictions up to 2030. Being a more mature market there is also good data from marketplace suppliers.

Element Energy has assessed the data and applied engineering knowledge to produce a set of base case assumptions to be used in BEIS analysis.

The cost and efficiency of an Alkaline electrolyser includes:

- The electrolyser system
- All necessary balance of plant (drier, cooling, de-oxo equipment, de-ionisation)
- Civil works for the electrolyser (building + foundations)
- Grid connection
- Compression

Pressure:

Typical output pressure are 2 – 3 MPa, whilst there is work currently ongoing to increase the output pressure it is not expected to exceed 6 MPa. Therefore an additional compression step will always be needed for alkaline electrolyser plants which are injecting into the transmission system. Compression adds additional capex, fixed and variable opex, though these are typically lower than the cost of the electrolyser itself. Compression costs are discussed below.

(1) Development of Water Electrolysis in the European Union - http://www.fch.europa.eu/sites/default/files/study%20electrolyser_0-Logos_0_0.pdf

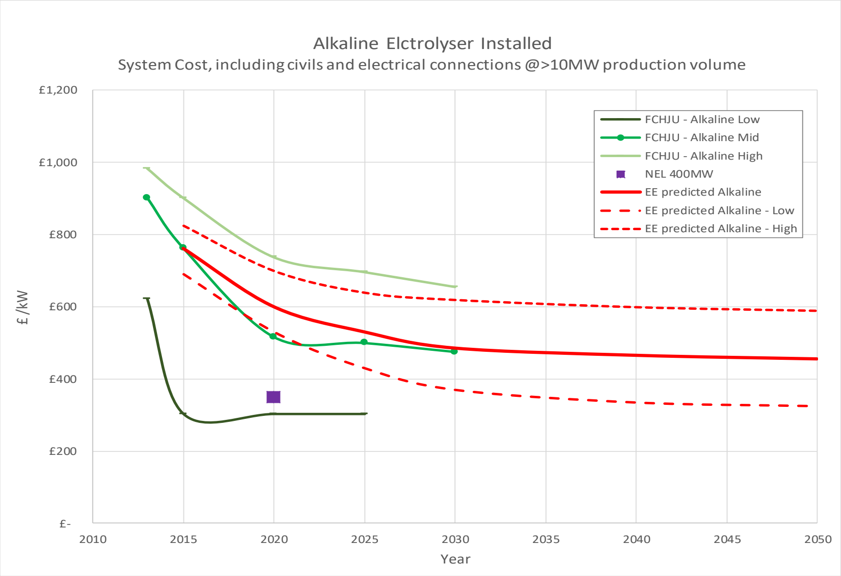
Hydrogen Production – Electrolysers (Alkaline)

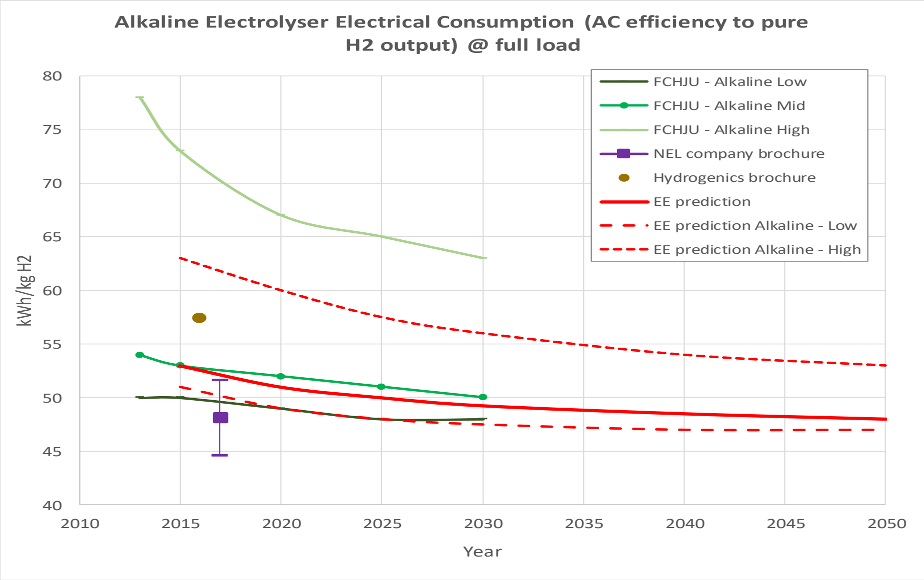
Alkaline Electrolysers

As with PEM electrolysers, Element Energy has assessed the available data from previous studies and industry publications. From these sources, we have been able to plot predictions on cost and efficiency.

The plots assume the plant size is >10MW and expected to be in the 100's MW.

The marginal difference between the Alkaline and PEM cost and efficiency curves are a result of Alkaline being a more mature technology and there is therefore less cost reduction expected with development, scale and sales volume.





Hydrogen Production – Electrolysers (SOE)

Solid Oxide Electrolysers

High temperature solid oxide electrolysis (SOE) is an immature production technology with the potential to be a future large scale production method. The particular advantage of SOE is the ability to make use of industrial sources of waste heat to improve the overall efficiencies. Indeed, if the energy cost of the waste heat is not included in the calculation, SOE electrical efficiencies can exceed 100%.

SOE is not currently commercially available and demonstration cells are nowhere near the scale of PEM or Alkaline. There is still considerable development required to get a commercially ready, scalable system with an acceptable stack replacement life. They currently have a short life due to the high operating temperatures in the process.

The largest systems installed to date are in the 10 to 100kW range and these have been installed as proof of principle units rather than as truly commercial offerings.

This image shows a Sunfire solid oxide electrolyser which was developed with Boeing for the US Navy in a demonstration project. It is one of the largest systems installed and operating today. This system can deliver approximately 4kg of hydrogen per hour.

Image source: www.renewableenergyfocus.com

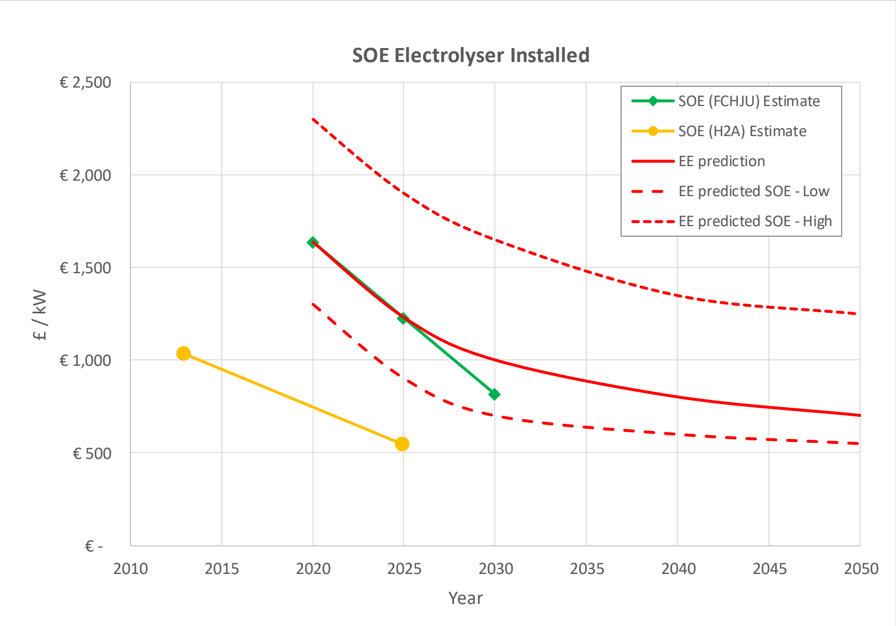
Hydrogen Production – Electrolysers (SOE)

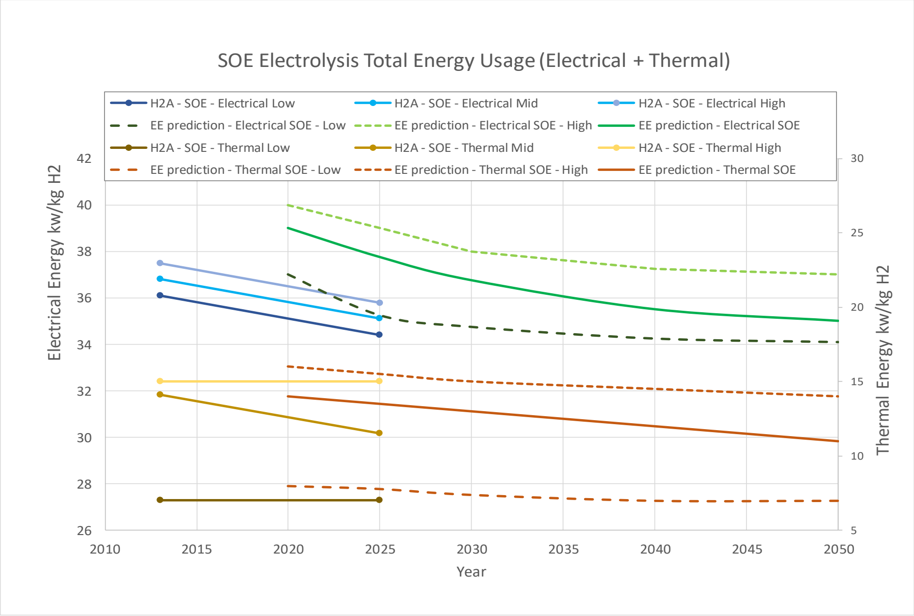
Solid Oxide Electrolysers

As they are not commercially available, the available data on the future development is limited. The FCH JU Electrolyser study[1] and the US Department of Energy H2A[2] both give figures for likely cost and efficiency. However, both are very speculative, and the US H2A projection for 2015 has been missed.

Central, upper and lower bound projections for cost and efficiency are shown below, though it should be noted that given the lack of units in the field, there is considerable uncertainty in these numbers.

Note: Thermal energy is expressed in electrical energy input in common with other electrolyser inputs.





(1) Development of Water Electrolysis in the European Union - http://www.fch.europa.eu/sites/default/files/study%20electrolyser_0-Logos_0_0.pdf
(2) US Department of Energy - http://www.hydrogen.energy.gov/h2a_analysis.html

Summary: Key assumptions for Electrolysers

Assumptions for electrolyser capital costs and energy efficiency

Capex £/kW (electrical input) installed:

Technology	Scenario (Year →)	2020	2025	2030	2035	2040	2045	2050
Electrolyser_PEM	LOWER	700	450	330	302.5	275	270	265
	BASE	**750**	**500**	**400**	**375**	**350**	**345**	**340**
	UPPER	1050	880	780	720	660	640	620
Electrolyser_Alkaline	LOWER	530	430	370	352.5	335	330	325
	BASE	**600**	**530**	**485**	**475**	**465**	**460**	**455**
	UPPER	700	640	620	610	600	595	590
Electrolyser_SOE	LOWER	1300	900	700	650	600	575	550
	BASE	**1640**	**1230**	**1000**	**900**	**800**	**750**	**700**
	UPPER	2300	1900	1650	1500	1350	1300	1250

Electrical Efficiency kW (electrical input) / kg H2:

Technology	Scenario (Year →)	2020	2025	2030	2035	2040	2045	2050
Electrolyser_PEM	LOWER	48.5	47.5	46.8	46.1	45.5	45.3	45.0
	BASE	**55.0**	**52.0**	**50.0**	**49.3**	**48.5**	**48.3**	**48.0**
	UPPER	64.0	59.0	55.5	54.0	52.5	52.0	51.5
Electrolyser_Alkaline	LOWER	49.0	48.0	47.5	47.3	47.0	47.0	47.0
	BASE	**51.0**	**50.0**	**49.3**	**48.9**	**48.5**	**48.3**	**48.0**
	UPPER	60.0	57.5	56.0	55.0	54.0	53.5	53.0
Electrolyser_SOE	LOWER	37.0	35.3	34.8	34.5	34.3	34.2	34.1
	BASE	**39.0**	**37.8**	**36.8**	**36.1**	**35.5**	**35.3**	**35.0**
	UPPER	40.0	39.0	38.0	37.6	37.3	37.1	37.0
Electrolyser_SOE (Thermal)	LOWER	8.0	7.8	7.4	7.2	7.0	7.0	7.0
	BASE	**14.0**	**13.5**	**13.0**	**12.5**	**12.0**	**11.5**	**11.0**
	UPPER	16.0	15.5	15.0	14.8	14.5	14.3	14.0

Hydrogen Production – Electrolysers

Additional Information

- Water consumption:
  - Water consumption varies with the purity of the water feed.
    - For demineralised water typically 0.9 litres per Nm^3 is quoted by manufacturers, equating to 10.5 litres water per kg hydrogen.
    - For tap water this rises to 1.5 to 2.0 litres per Nm^3 due to the requirement for a Reverse Osmosis system, equating to 18 to 22 litres / kg hydrogen (or 0.45 to 0.55 litres per kWh HHV)
    - For brine or grey water feedstock this would increase, as would the cost of the purification stage.
- Plant footprints:
  - An alkaline electrolyser plant would require 0.136 m^2/kW H_2 HHV output (inc. all balance of plant)
  - A PEM electrolyser plant would be 0.0737 m^2/kW H_2 HHV output (inc. all balance of plant)
  - There isn't data available on the size of SOE so Element Energy assume this is equivalent to Alkaline at 0.136m^2/kW H_2 HHV output
- Output purity:
  - An electrolyser system will typically output very pure hydrogen (>99.95%) with moisture and oxygen being the most probable impurities.
  - With a very simple drier and filter these impurities are removed and purity of >99.999% is readily available.
- Response rates:
  - PEM and Alkaline can be cycled from 0% to 100% to 0% in minutes.
  - SOE is less suitable for cycling due to high temperatures required in the process but is expected to be capable of a cycle in less than one day.

Standalone Integrated Renewable Electrolysis

Direct connection of onshore wind to electrolysers

The other option is to directly couple the electrolyser to a source of renewable (or other) generation. We represent this using a dedicated technology, described below:

Production Technology:

- A purpose built onshore (or offshore) wind farm directly coupled to electrolysis for the production of renewable hydrogen for grid injection. This would be built if the electricity price (generation + distribution) becomes prohibitive but the system still requires low carbon electrolytic production.

Benefits:

- No requirement for or incurred cost from the electricity transmission network.
- Access to low cost electricity direct from the generator

Argument against:

- Electricity could potentially be traded at higher price to the transmission network.
- Limited/finite overall resource for renewable generation across the UK

Basis for costing:

- Onshore wind (>5MW) data taken from BEIS generation costs report [1], combined with electrolyser and 'medium pressure' storage data to create a technology to supply hydrogen with integrated power production. Base and lower costs have been derived.
- Offshore wind R3 (Round 3)[2] has been used to derive a High scenario (using the lower costs from the BEIS generation cost report [1] and the Lower cost scenario for electrolysers).

(1) - https://www.gov.uk/government/publications/beis-electricity-generation-costs-november-2016
(2) - https://www.thecrownestate.co.uk/energy-minerals-and-infrastructure/downloads/round-3-offshore-wind/

Standalone Integrated Renewable Electrolysis

Direct connection of onshore wind to electrolysers

- This gives two options:
  - Wind turbine capacity matched to electrolyser outputting with Load Factor of 0.32 (uses system storage at times of low demand)
  - Wind turbine capacity and electrolyser scaled up and combined with storage to increase effective Load Factor to be comparable with dispatchable hydrogen production technology.
- The analysis below is based on the latter option with three days of storage available as such (crudely) increasing the Load Factor to 0.96. [Higher scenario of Offshore R3 wind has a 0.48 load factor so only requires two days storage]
- For example a system outputting 10 MW hydrogen HHV would include(1) the costs below and is equivalent to £137/MWh of hydrogen (HHV), with a 20 year loan at 5%.

Component	Size	Capex /£M	Fixed Opex /£M/year	Variable Opex /£/kWh H2 HHV
Wind Farm (onshore)	43.6 MW	£ 64.3 M	£ 1.04 M/year	£ 0.0070 /kWh H2 HHV
PEM Electrolyser Plant	43.6 MW (elec) *(31.2 MW H2 HHV)*	£ 32.7 M	£ 0.914 M/year	£ 0.0077 /kWh H2 HHV
Medium Pressure Storage	2.25 GWh	£ 8.59 M	£ 0.255 M/year	-------
TOTALS	**Equivalent 10 MW H2 HHV continuous output**	**£ 105.6 M**	**£ 2.21 M/year**	**£ 0.0147 /kWh H2 HHV**

(1) – Costs for 2020, PEM electrolyser, Base Cases, incorporating 0.96 Load Factor correction

- **Hydrogen Production**
  - Hydrogen Purity
  - Electrolysis
  - **Reforming**
  - Gasification
  - Liquid hydrogen import
  - Compression

Our Approach in This Work

1. Validate CAPEX data for SMR hydrogen production

- Use the IEAGHG CAPEX datapoint to compare with Jacobs' in-house CAPEX data for SMR hydrogen production
- Derive a cost curve relationship between capacity and CAPEX based on Jacobs' in-house data

2. Evaluate options for carbon capture based on SMR

- Use the recent IEAGHG report as the initial basis for CAPEX and OPEX estimations
- Develop cost curves for these different carbon capture options

3. Evaluate alternative hydrogen production technologies

- Autothermal Reforming (ATR) technology as the main alterative process route to SMR for "low carbon" hydrogen production through reforming of natural gas. It has similar capex to SMR technologies at higher capacities, however it offers much higher capture rate (95% vs 90%)
- We see GHR as a very promising technology enhancement for H2 production with carbon capture, particularly in combination with ATR technology
- This is based on information gathered through industry consultation and Jacobs experience on similar projects/in-house data

4. Evaluate information submitted through peer and industry review

- The industry review also highlighted key developments in Auto-Thermal Reforming (ATR) technology.
- Through incorporation of GHR within the ATR processing scheme, as well as other ATR improvements, further significant improvements have been modelled.

Technology Overview - Hydrogen Production by Reformer Technology

Syngas Generation

- Steam Methane Reformation (SMR)
- Autothermal reforming (ATR) and Partial Oxidation (POx)
  - Lower number of references for hydrogen production, but technologies are mature
  - Preferentially used in large scale industries e.g. synthetic fuels and commodity chemicals
  - SMR + ATR Combined Reforming (as used in ammonia and methanol production)
- Gas Heated Reformer (GHR). GHR is not a self-sufficient reforming technology. An external heat source is required to meet/supplement the reforming needs of the GHR. This is typically provided by combining a GHR unit with a high temperature heat source (reformed gas) from an ATR or SMR.

CO_2 Removal

- Amine based systems
  - Amine based CO_2 removal systems are mature technologies. Selexol is also competitive at large capacities and where the cost of power is high.
  - Technological improvements include better heat integration, reduced fouling of solvents and improved corrosion efficiencies.

H_2 Extraction

- Pressure Swing Adsorption (PSA)
  - Mature technology available at large capacities and high purity requirements
  - Technological improvements include increased reliability and longer absorbent lives.
- Membranes
  - Technology is maturing, however is associated with lower purity H_2 product and increased operating costs

JACOBS Consultancy

IEAGHG Report [1] - SMR Hydrogen Production

- IEAGHG Report: Techno-Economic Evaluation of SMR Based Standalone H2 Plant with CCS (2017)
- Prepared by Amec Foster Wheeler (AFW, now Wood)
- Chosen as the main reference as it is a recent study, has an engineering basis, and provides a detailed breakdown of cost estimates
- Class 4 cost estimates developed (+35%/-15%) for SMR without carbon capture, and 5 alternative cases with carbon capture. Site location is the North East coast of The Netherlands.
- Two main costs presented, TPC & TCR
  - TPC = Total Plant Cost (including the 20% contingency which is standard in engineering assessments at the early stage of plant design)
  - TCR = Total Capital Requirement, which is TPC + interest during construction, spare part costs, working capital , start-up costs and Owner's costs
  - **We have based our analysis on TPC values**
- **Base Case – No CCS → *Used for cost comparison with Jacobs in-house data***
- **Case 3: CO_2 Capture from flue gas using MEA [1] → *Proposed as the base case for analytical work***

[1] IEAGHG Report: Techno-Economic Evaluation of SMR Based Standalone Hydrogen Plant with CCS (February 2017)

Hydrogen Production - SMR

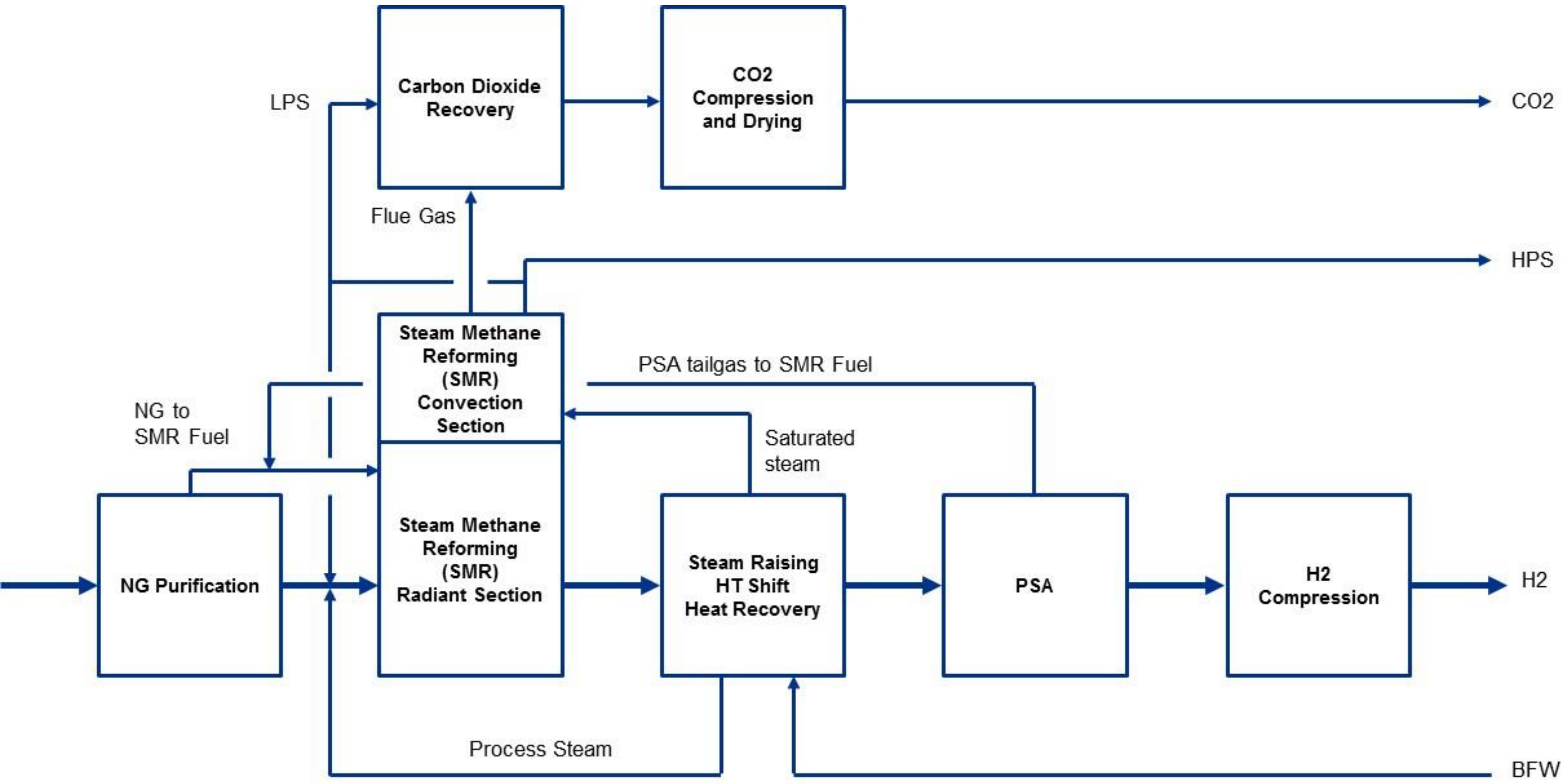
Technology Overview - SMR

- Mature technology and widely used across the refining and petrochemical industries.
- Improvements have included higher performing materials, improved heat recovery, lower pressure drop and higher conversion catalysts.
- Typical capacities ~20 MMSCFD (22 kNm^3/h or 74 MW H2 HHV) to world scale capacities of 150 - 200 MMSCFD (168 - 224 kNm^3/h or 564 – 739 MW H2 HHV).
  - Example large scale proven single train SMR plants:
    - Garyvillle, USA: 120 MMSCFD (134 kNm^3/h or 450 MW H2 HHV)
    - Baton Rouge, USA: 120 MMSCFD (134 kNm^3/h or 450 MW H2 HHV)

Carbon Capture from SMR Hydrogen Production

- Two main sources of CO_2 production:
  - CO_2 produced from the chemical reactions of the process
  - CO_2 production from the combustion of the fuel that is required to provide heat for the endothermic process reactions.
- Source 1) relatively easy to capture as a high purity stream, especially using an amine solvent.
- Source 2) relatively difficult (i.e. expensive) to capture, due to diluted concentration of CO_2 and pressure at atmospheric condition.
- Carbon capture solutions that aim to recover both sources are much more capital intensive than those that focus just on Source 1) .
- The AFW Case 3 captures the CO_2 from the Flue gas.

SMR Case – Flow scheme



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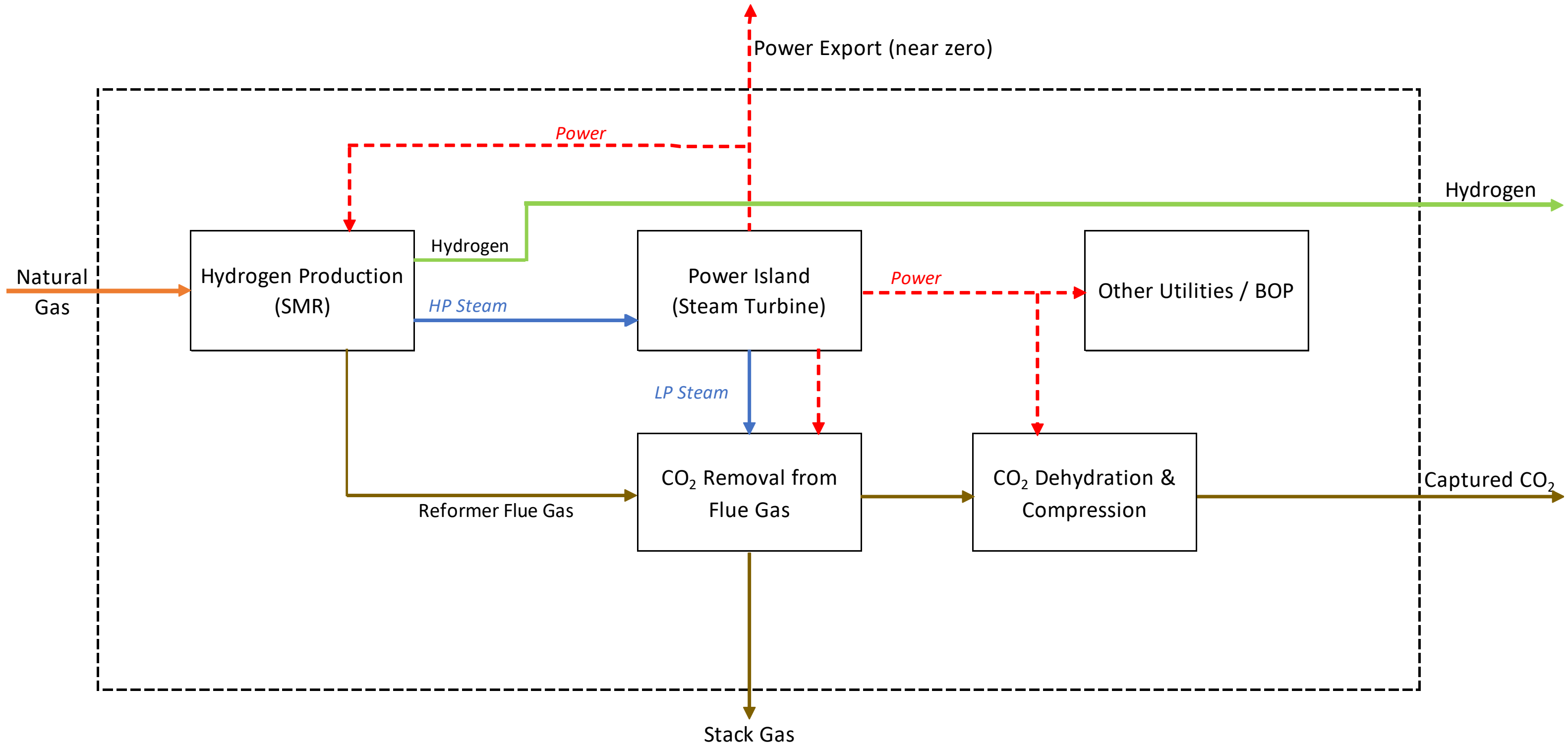
SMR Case – Plant Boundaries



- For an SMR without carbon capture, "excess" steam generated in waste heat boilers (WHB) by cooling of the reformed gas would be exported. In the post-combustion carbon capture case, this steam is used to meet the parasitic heat demand of amine regeneration in the CO_2 capture section. Power is generated from expanding this steam in a steam turbine from high pressure (HP) to low pressure (LP). This power generation is sufficient to meet the power demand of the overall plant, with a very small net export.

[1] IEAGHG Report: Techno-Economic Evaluation of SMR Based Standalone Hydrogen Plant with CCS (February 2017)

Hydrogen Production - ATR

Technology Overview - ATR

- In the ATR technology, part of the natural gas feed is partially combusted to generate heat for the endothermic reforming reaction. This self-heating ('auto-thermal') mechanism largely eliminates the need for any external heating, which can be met with supplemental hydrogen firing.
- The H_2/CO ratio from ATR technology is less suited to hydrogen production than SMR, more suited to Fischer–Tropsch processes, so technology has to be "re-optimized" for hydrogen production.
- Numerous ATRs are in operation worldwide, but most operate as secondary reformers in ammonia plants in collaboration with SMR technology. For ammonia plants, stand-alone ATR technology has so far been considered uneconomical. For methanol plants, only a few true stand alone ATRs have been realized up to now, but ATR technologies are maturing steadily.
- The high CAPEX cost of capturing CO_2 from SMR flue gas makes the use of ATR more attractive for "blue" hydrogen production, especially if CO_2 capture rates >90% required.

Carbon Capture from ATR Hydrogen Production

- On the positive side, use of oxygen instead of air for natural gas combustion avoids the need for expensive post-combustion separation of CO_2 from nitrogen.
- On the negative side, the ATR technology requires an Air Separation Unit (ASU) which commands high CAPEX as well as OPEX due to associated additional power demand.
- If a portion of the hydrogen produced is used as fuel to generate power to meet the plant's power requirement, CO_2 capture rates of 95% can be achieved with ATR technology (versus 90% maximum for SMR technology). This makes ATR particularly attractive where there is low carbon grid factor electricity available. Where internal power demand has to be self-generated, higher CO_2 capture rates can only be maintained by using hydrogen as combined cycle gas turbine fuel.

Hydrogen Production - ATR

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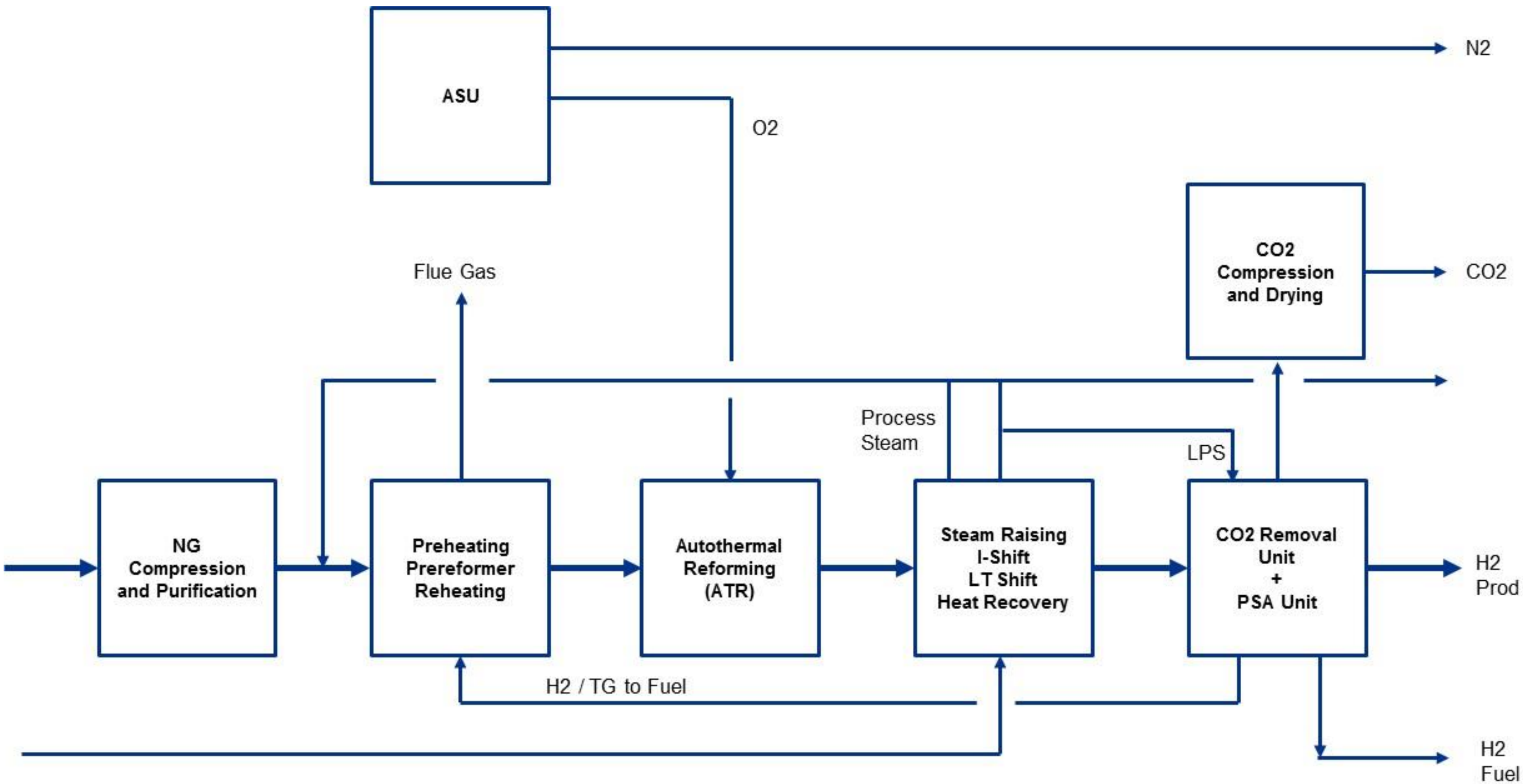
ATR Case – Flow scheme



Hydrogen Production – ATR (power import case)

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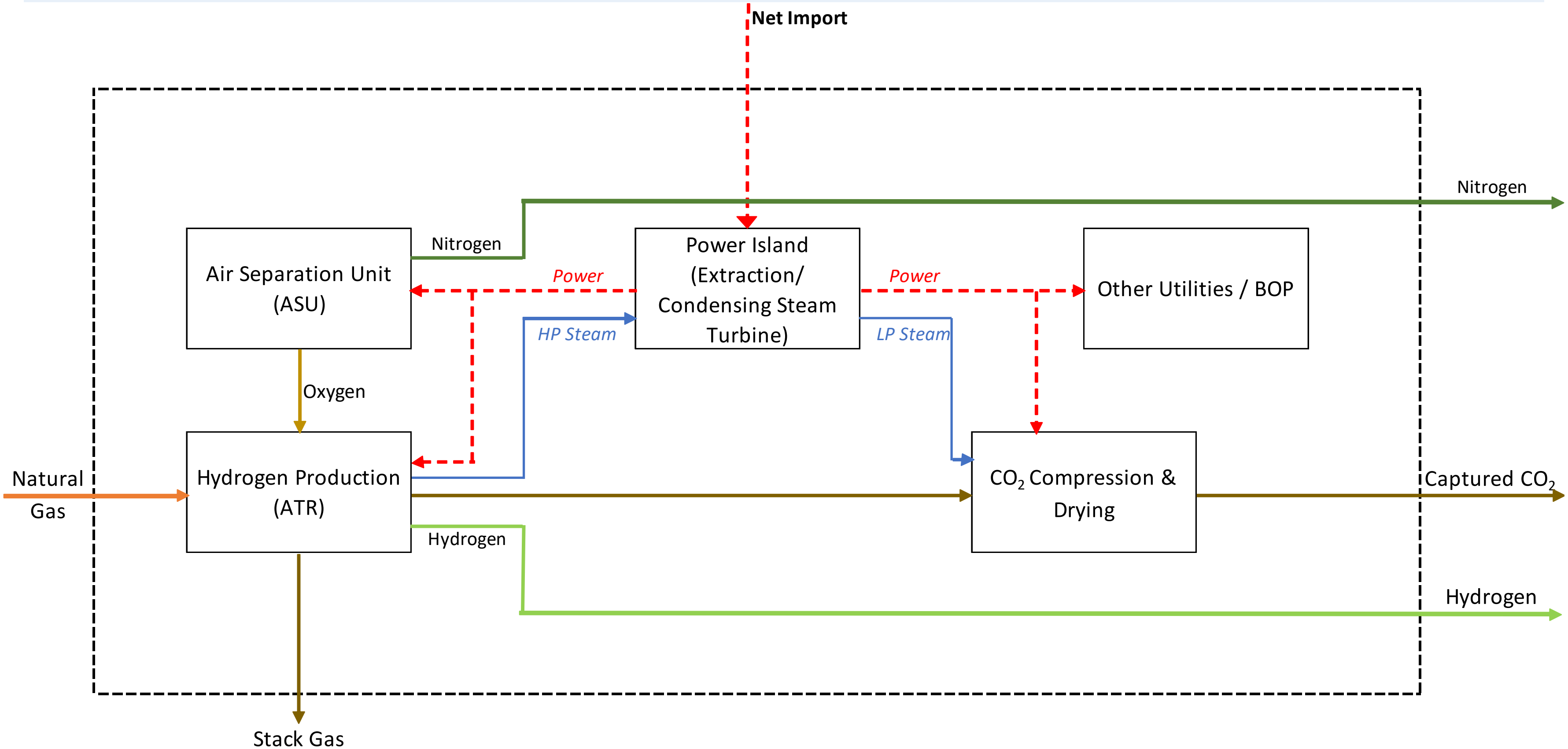
ATR Case – Plant Boundaries



- Flowsheet includes a steam turbine for power generation, with an extraction stage for LP steam demand, and a condensing stage for excess steam from the ATR.

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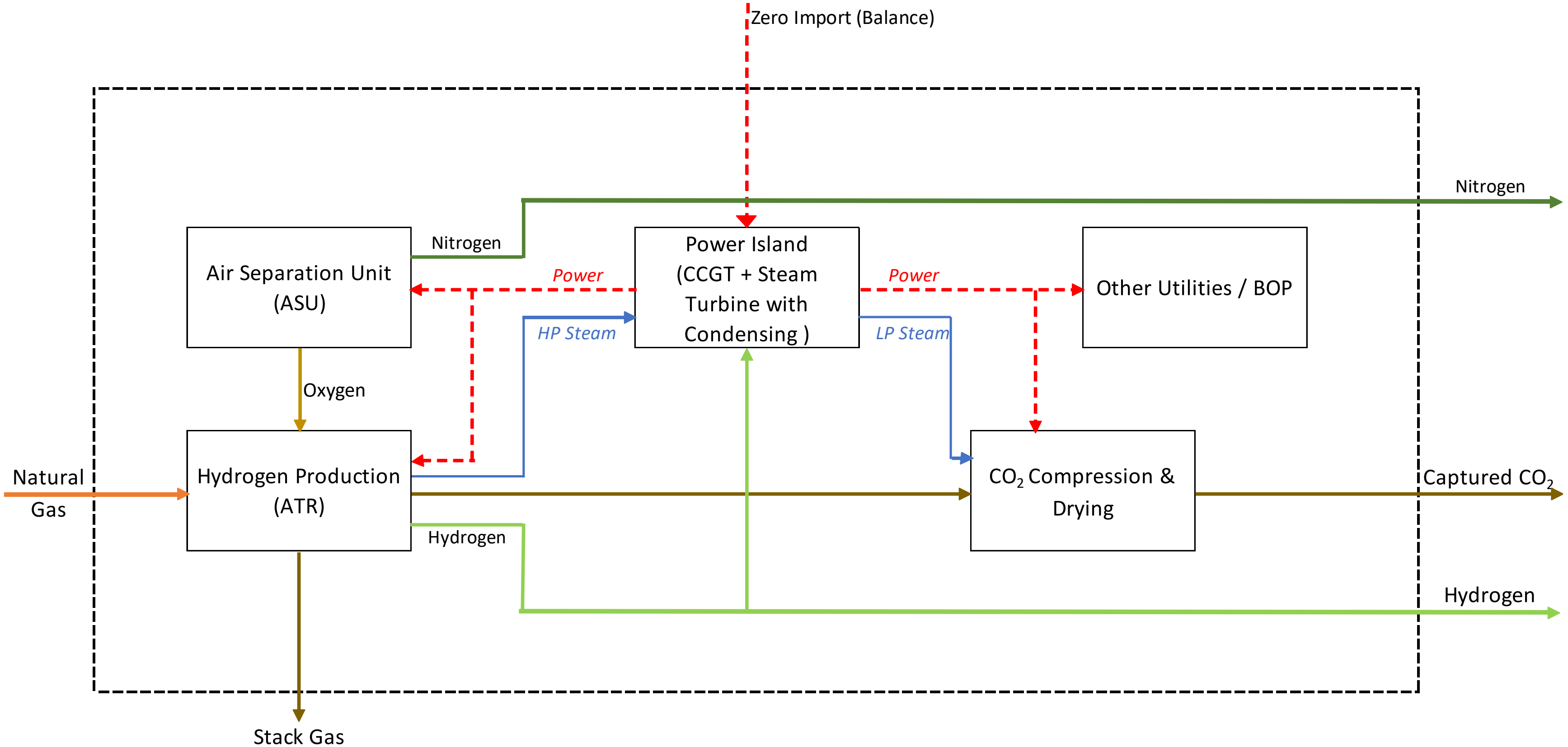
ATR Case – Plant Boundaries



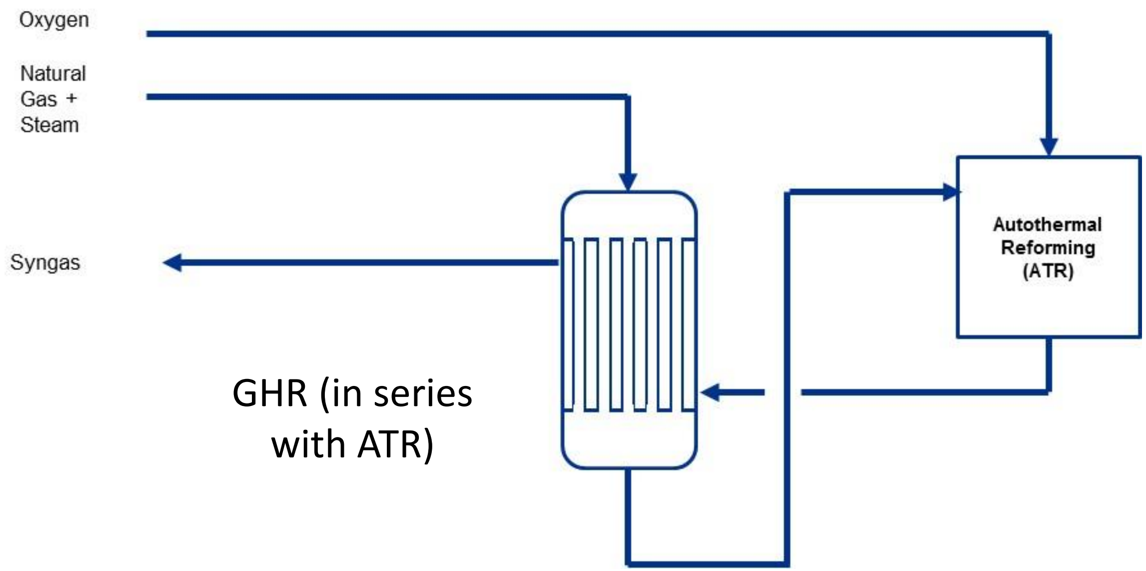
- Net power demand of hydrogen production (including ASU and CO_2 compression) met by hydrogen-fired combined cycle gas turbine (CCGT).

Hydrogen Production – ATR Case including GHR

GHR Enhancement to ATR

- Heat exchange reforming (or Gas Heating Reforming) is where the reforming takes place in a tubular heat exchanger where the heat for reaction comes from another gas stream typically the reformed gas of an ATR .
- There are two variants – parallel offered by KBR and Haldor Topsøe and series, offered by Johnson Matthey. The parallel variant is less expensive than the series version, but the series version has the advantage of decreased methane slip and therefore can achieve higher carbon capture.

GHR has been demonstrated on a semi- commercial scale for over 20 years at the Coogee methanol plant in Australia (now dismantled), although not currently for stand-alone hydrogen production.



GHR (in series with ATR)

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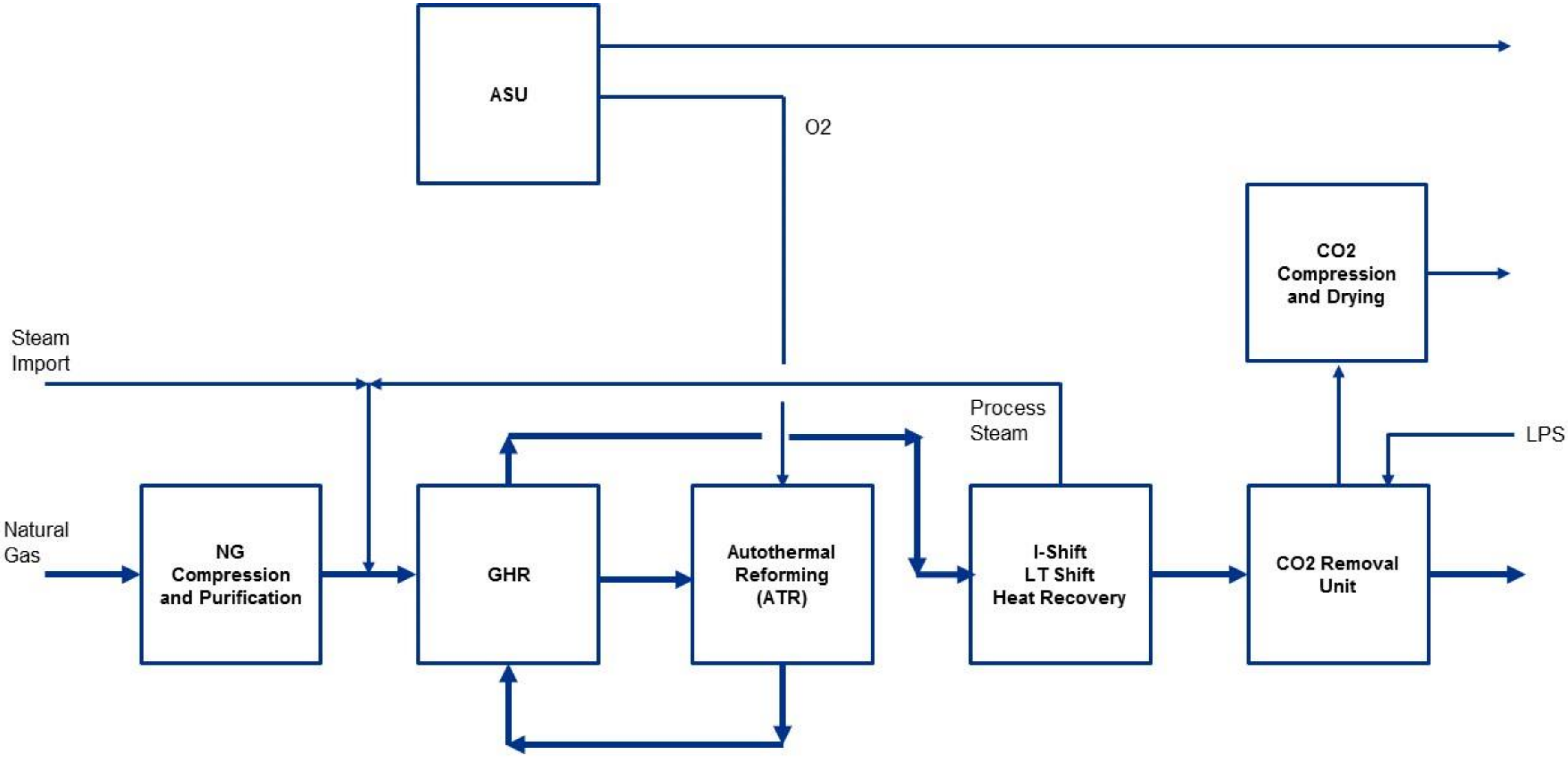
ATR+GHR Case – Flow scheme



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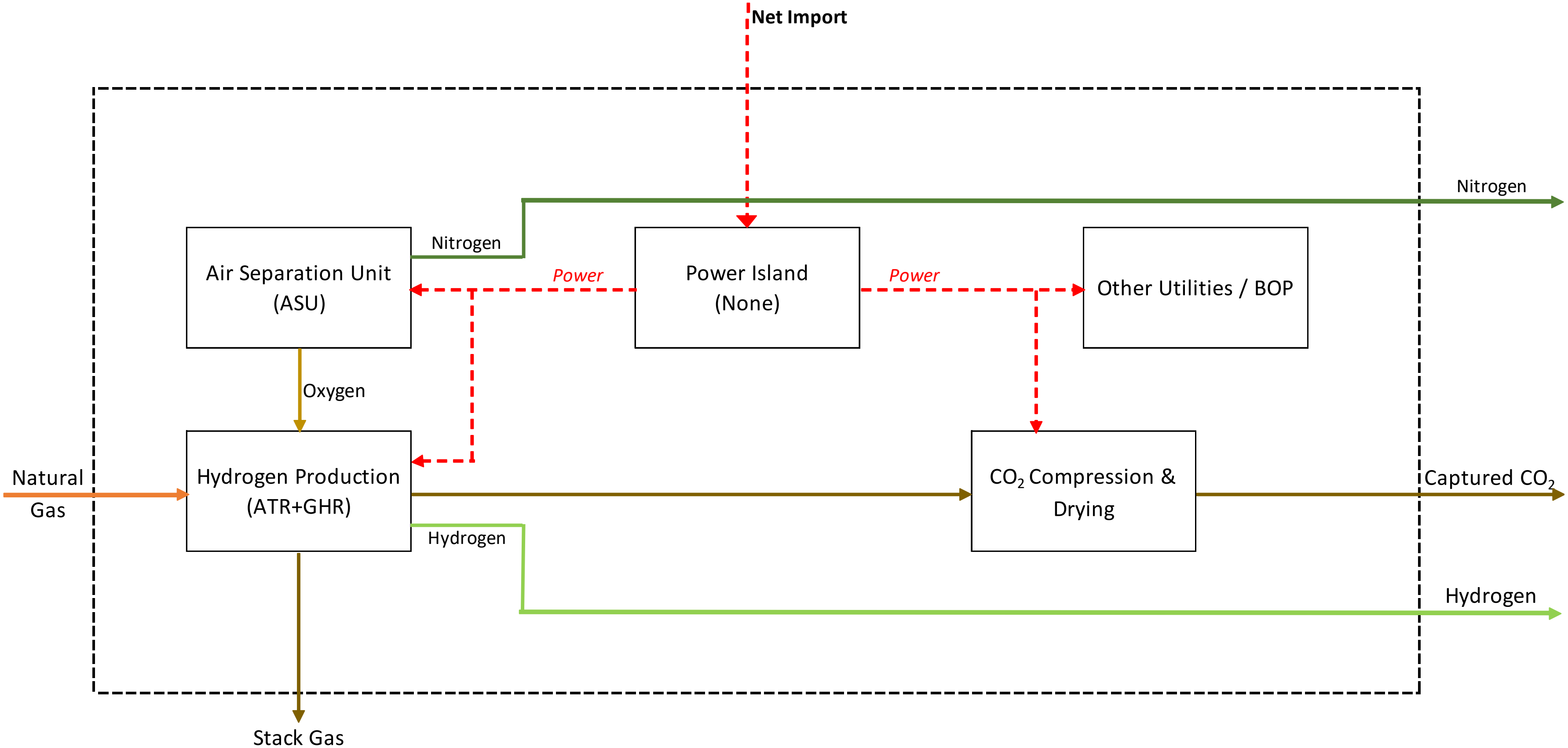
ATR+GHR Case – Plant Boundaries



- Net power demand of hydrogen production (including ASU and CO_2 compression) met primarily by power import.

IEAGHG SMR CAPEX vs CO_2 Recovery

	Total Plant Cost		CO2 Capture Delta	CO2 Capture
	Million €	Million £	Million £	%
336 MW H2 HHV				
Base Case Case - No SMR	171.0	133.3		
Case 1A	201.8	157.4	24.1	55.7
Case 1B	228.5	178.2	44.9	66.9
Case 2A	226.1	176.3	43.0	54.1
Case 2B	241.4	188.3	55.0	53.2
Case 3	**305.3**	**238.2**	**104.8**	**90.0**

- The project team agrees that **only Case 3 is a viable option** for high levels of heat decarbonisation - 90% capture of CO_2 appears the minimum required for the effort of creating a hydrogen based heating system.
- Note that CO_2 emissions factors could be improved if a waste heat source was used to raise the steam for the SMR process. However given the scale of production anticipated for the 100% hydrogen network, it is assumed that this will only be feasible in niche locations and does not represent a system wide opportunity.
- GHR integration with an SMR flow scheme has not been included for evaluation in this analysis as the primary purpose of such integration is for debottlenecking an existing SMR. We do not see significant benefits of a combined GHR/SMR scheme over SMR for low carbon hydrogen production.

[1] IEAGHG Report: Techno-Economic Evaluation of SMR Based Standalone Hydrogen Plant with CCS (February 2017)

Hydrogen Production - Reformers

JACOBS Consultancy

2018 CAPEX Curve Assumptions

- SMR Post-Combustion Case (Amec FW) scaled using a factor of 0.74, and updated to 2018 pricing. We would expect a stand-alone SMR to have a maximum single train capacity of 1600 MW H2 HHV. However for this case, we believe the single train capacity is limited to 1000 MW H2 HHV by the maximum size of the carbon capture plant (and in particular, the required diameter of the amine absorber).
- ATR case based on CCSA feedback and in-house Jacobs data. We would expect to have a maximum ATR single train capacity of 1400 MW H2 HHV, limited by heat flux on the waste heat boiler (WHB) downstream of the ATR. We have also specified a minimum size of 300 MW H2 HHV, as we do not think the associated ASU CAPEX would be economical below this size.
- ATR+GHR case based on licensor information and in-house modelling. We have limited the maximum ATR+GHR size to 1300 MW H2 HHV, based on a maximum limit of 2 GHR per ATR. We have again specified a minimum size of 300 MW H2 HHV, as we do not think the associated ASU CAPEX would be economical below this size.
- Within the accuracy of the CAPEX estimate, the incremental CAPEX for the PSA unit and tail gas compressor for the 99.9% purity case vs 98% not considered significant.

[1] Schoots et al., Learning curves for hydrogen production technology: An assessment of observed cost reductions (2008)

Cost-Time Curve CAPEX Assumptions

- SMR is a mature technology, and thus low real term cost reduction is expected.
- Literature studies have estimated that since 1940, the unit cost of hydrogen production by SMR has decreased by approximately 11%, for every doubling of cumulated amount of hydrogen capacity. [1]
- Historic data from the same studies can also be used to approximate that the average doubling time for hydrogen production capacity by SMR to date. This is around 9.2 years.
- Therefore we have assumed an average annual cost reduction in SMR of $(1 - 0.89^{\frac{1}{9.2}})$ = 1.26%.
- We assume that ATR technology cost comes into effect from 2021 onwards while ATR+GHR is available from 2026.
- The costs of ATR and ATR+GHR are assumed to further reduce by 10% by 2030, thereafter it has same cost trends as SMR
- It is assumed that technologies within reformers will be developed in the future and the cost / efficiencies specifications encompass future developments.

[1] Schoots et al., Learning curves for hydrogen production technology: An assessment of observed cost reductions (2008)

Cost-Time Curve OPEX Assumptions

- Operational cost are assumed to represent same share of capex in future.
- Total OPEX Cost considerations include [1]:
  - Fixed Costs
    - Direct Labour, Administration / General Overheads, Insurance / Local Taxes, Maintenance
  - Variable Costs
    - Raw Water (make-up), Chemicals & Catalysts
  - Fuel Costs
    - Feedstock (natural gas), electricity required for air separation unit

- Natural gas demand is split into natural gas required for hydrogen production and natural gas required for heating processes. With the latter defined as ‘Waste Heat’ demand in the analytical work.

(1) - IEAGHG Report: Techno-Economic Evaluation of SMR H2 Plant with CCS (2016)

Hydrogen Production – Reformers – cost assumption

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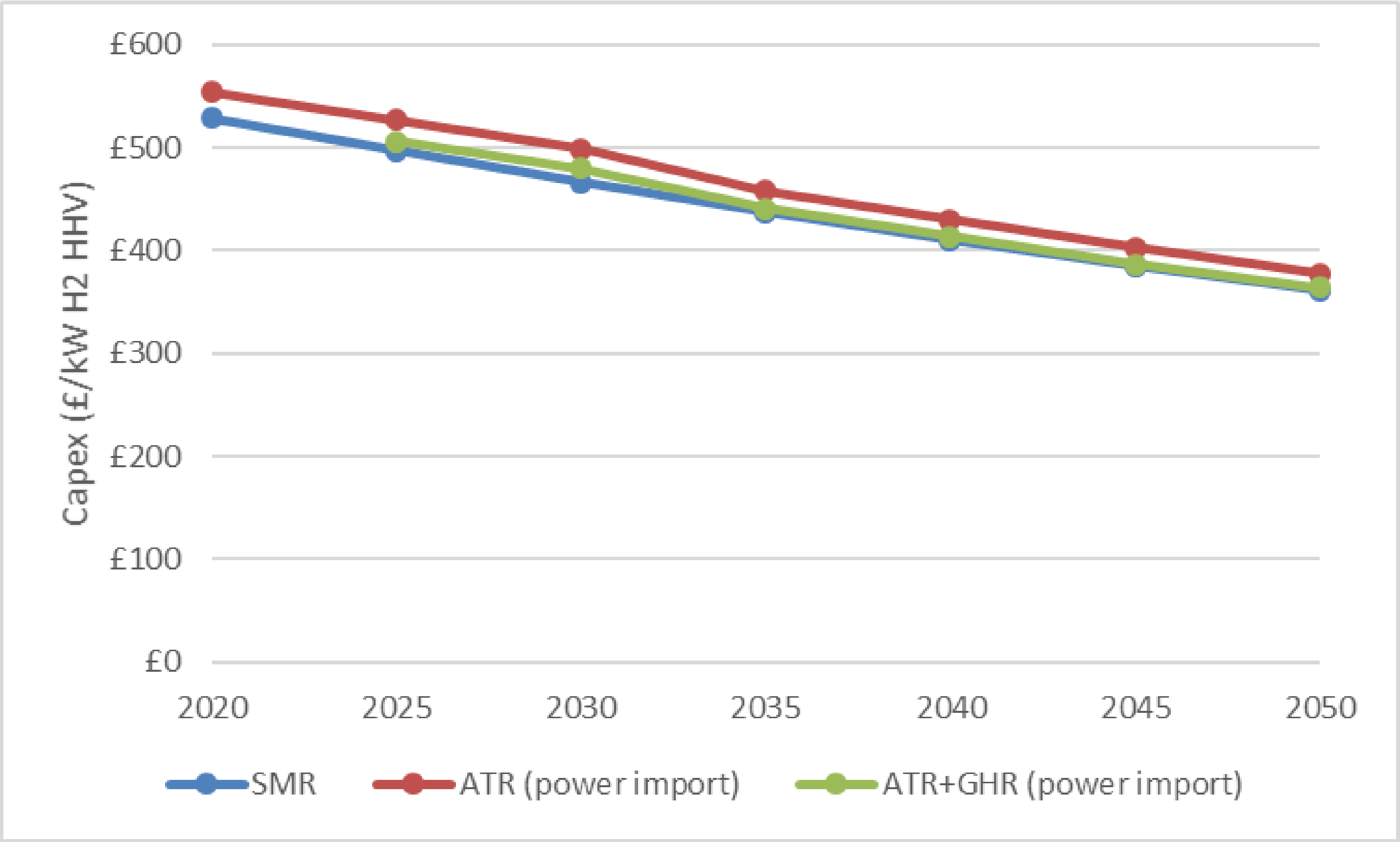
CAPEX Cost over time for three cost scenarios (power import case)



Summary: Key assumptions for SMR

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Key assumptions for Reforming (power import case)

Current capex (£/kW H2 HHV) for different capacities:

Technology	Plant capacity (MW H2 HHV)						
	100	200	300	400	500	750	1000
SMR	£918	£785	£700	£647	£610	£550	£529
ATR			£822	£744	£697	£610	£554
ATR+GHR			£790	£715	£670	£586	£533

Future capex (£/kW H2 HHV) reduction (based on a typical plant size of 1000MW)[1]:

Technology	2020	2025	2030	2035	2040	2045	2050
SMR	£529	£497	£466	£437	£410	£385	£361
ATR	£554	£527	£499	£458	£430	£403	£378
ATR+GHR		£506	£480	£441	£414	£387	£364

Opex (for all years):

Technology	Fixed opex (£/kW/y)	Variable opex (£/kWh H2)	Natural gas (kWh/kWh H2)	Electricity (kWh/kWh H2)	CO2 capture rate (%)
SMR	£25.38	£0.00013	1.355	0	90%
ATR	£24.41	£0.00013	1.197	0.059	95%
ATR+GHR	£24.41	£0.00013	1.115	0.042	95.7%

The ATR+GHR (with GHR in series) results are based on simulations estimates that Jacobs have made, but not on a full design, and can be considered “aspirational” as a future case, given that the GHR design (in series) is less proven at scale. There is uncertainty with regards the cost estimates too, given again that a GHR has never been built on this scale.

1 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/190149/16_04-DECC-The_Future_of_Heating_Accessible-10.pdf - The current peak heating demand is ~ 300GW

Summary: Key assumptions for SMR

JACOBS Consultancy

Key assumptions for Reforming (self sufficient case)[1]

Current capex (£/kW H2 HHV) for different capacities:

Technology	Plant capacity (MW H2 HHV)						
	100	200	300	400	500	750	1000
SMR	£918	£785	£700	£647	£610	£550	£529
ATR			£965	£873	£818	£716	£651

Future capex (£/kW H2 HHV) reduction (based on a typical plant size of 1000MW):

Technology	2020	2025	2030	2035	2040	2045	2050
SMR	£529	£497	£466	£437	£410	£385	£361
ATR	£651	£619	£586	£538	£505	£474	£444

Opex (for all years):

Technology	Fixed opex (£/kW/y)	Variable opex (£/kWh H2)	Natural gas (kWh/kWh H2)	Electricity (kWh/kWh H2)	CO2 capture rate (%)
SMR	£25.38	£0.000130	1.355	0	90%
ATR	£28.68	£0.000149	1.368	0	95%

1 Cost and performance assumptions for ATR+GHR self-sufficient case are excluded as they are still under review

Reformers – footprint and water requirements

Additional Information

- **Footprint:**
  - The US H2A study gives a land requirement of 14.2 acres for a 354 MW H2 HHV plant. Equating to 0.16 m^2 /kW H2 HHV.
  - Comparing with Amec Foster Wheeler plans for adding CCS to BOC's SMR in Teesside this gives a footprint of 0.107 m^2 /kW H2 HHV.
  - Recommend using the UK figure as likely to be more efficient with available space.
  - It is expected that ATR and GHR will be smaller than the incumbent and they currently quote size reductions of 75% for similar technologies utilising their reformers. It is suggested that a figure of 0.055 m^2 /kW H2 HHV is used for the Lower and Very Low scenarios.
- **Water Requirements:**
  - The (Base) AFW Case 3 SMR requires:
    - Raw water: 0.12 litres/kWh H2 HHV and Sea water: 30 litres/kWh H2 HHV (process cooling)*
  - The US H2A study gives a requirement of:
    - Demineralised water: 0.32 litres/kWh H2 HHV and Cooling water: 0.14 litres/kWh H2 HHV
  - The very large difference in cooling/sea water usage is the difference between using a cooling tower and the small temperature increase allowed for discharged sea water.
  - Suggest using AFW Case 3 numbers for Raw water of 0.12 litres/kWh H2 HHV*
- **Turn Down / Response rate:**
  - Due to the high temperature thermal processes a reforming plant output cannot be readily turned up and down (or on and off). Therefore, a reformer acts very much as base load production.
  - The minimum operating capacity of the plants are 70% with a turn up/down rate of not more than 10% in 24 hours. However, this constraint is relaxed in a fleet operation where the average load factor is lower than 70% during summer periods as some plants are shut down

** - Raw water is defined as non-purified water such as reservoir or rainwater. However, it is important to note that the 'dirtier' the raw water the more costly and energy intense the required purification would be e.g. heavily silted river water would require silt removal.*

- **Hydrogen Production**
  - Hydrogen Purity
  - Electrolysis
  - Reforming
  - **Gasification**
  - Liquid hydrogen import
  - Compression

Hydrogen Production – Coal Gasification

Hydrogen Production by Gasification Technology - Overview

General

Gasification technology allows for the transformation and upgrade of a solid fuel into a mixture known as syngas. This syngas may be separated and purified to produce high purity CO_2 and hydrogen streams.

The base case plant comprises an oxygen blown slagging gasifier fed with a world traded bituminous coal. The syngas produced is shifted and treated to remove sulphur and CO_2 before being upgraded further.

The base case plant comprises 7 main process units that utilise mature technologies:

- ASU – Cryogenic High Purity - Pumped cycle
- Gasifier – GE Energy with water quench
- Shift – Sour shift, two stage
- AGR – Selexol
- SRU – Claus, oxygen blown with tail gas recycle
- CO_2 Compression – Multi-stage integral gear compressor and TEG drying
- Methanation – single stage adiabatic methanator to convert residual carbon oxides

Future Developments

There are good technology development opportunities on the major flowsheet sections that have potential to reduce the CAPEX and OPEX of gasification based hydrogen.

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Our Approach in This Work

The following items are based on Jacobs extensive previous experience in the field of studying and designing gasification plant and engineering judgement.

- Present a base case technology overview
- Provide comment on feedstock position and basis
- Provide CAPEX data for Gasification Based Hydrogen Production
  - Cost relationship between capacity and CAPEX based on Jacobs' in-house data
- Evaluate options for future technology developments
  - Review the development technologies that may improve future CAPEX and efficiency
  - Develop cost curves for these improvements

Hydrogen Production – Coal Gasification

Technology Overview - Gasification

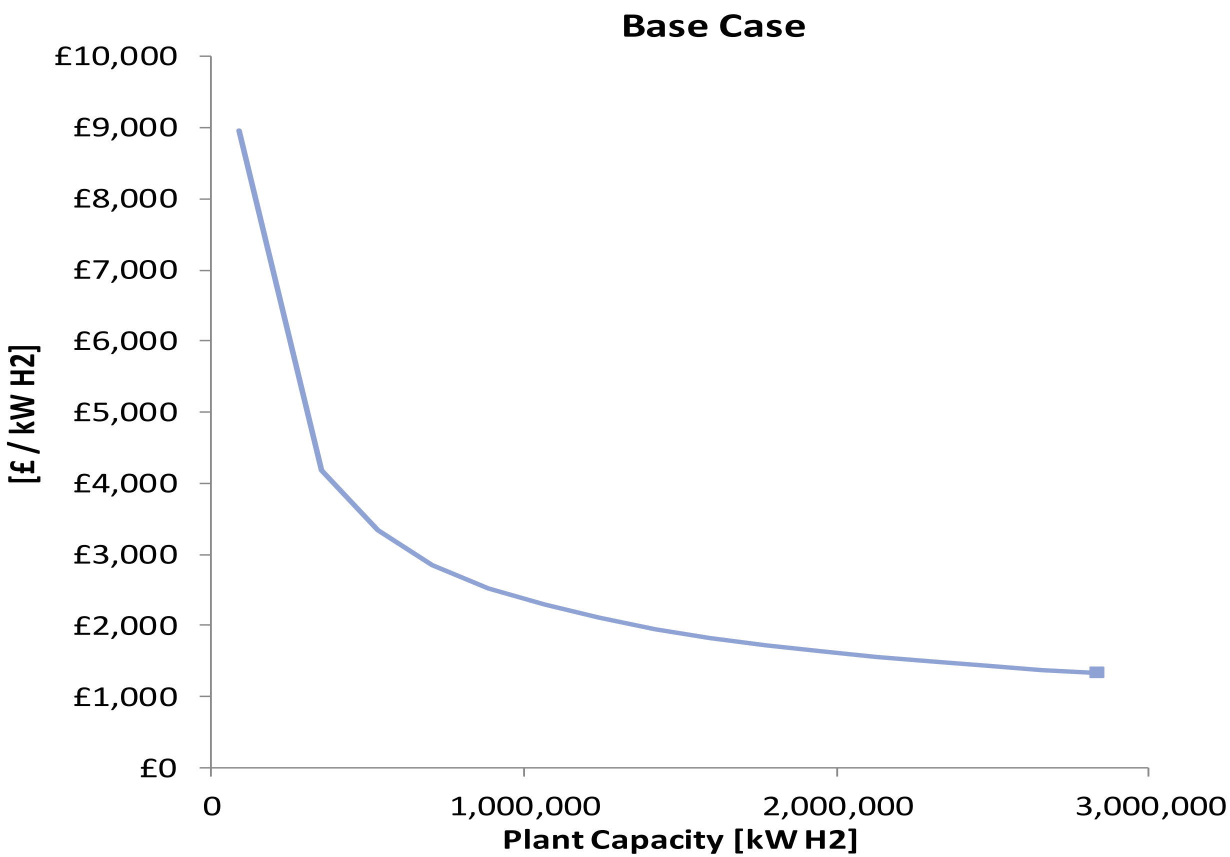
- Mature technology and widely used across the refining and petrochemical industries.
- Improvements have included higher performing refractory and metallurgy and process efficiency improvements.
- Typical capacities ~26 kNm^3/h (87 MW H2 HHV) to world scale capacities of 300 – 750 kNm^3/h. (1.0 – 2.5 GW H2 HHV)
    - World scale capacities use multiple gasifier trains.
    - Gasification based hydrogen production examples are:
        - Jamnagar, India: 300 kNm^3/h (1 GW HHV) (using petcoke)
        - Ordos, China: 145 kNm^3/h (487 MW HHV)
        - Xuzhou, China: 26 kNm^3/h (87 MW HHV)

Carbon Capture from Gasification Hydrogen Production

- Two main sources of CO_2 production:
    1. CO_2 produced from the chemical reactions of the process (relatively easy to capture as a high purity stream, especially using an amine solvent)
    2. CO_2 production from the combustion of the fuel that is required to generate steam for power generation (expensive to capture, due to dilute concentration of CO_2 and atmospheric pressure)
- The flowsheet assumes power import, enabling less carbon intensive power generation method to be used than could be achieved through combustion of coal.

Cost-Capacity Curve CAPEX: Gasification

- Scaling exponent of 0.45 based on Jacobs Consultancy experience with similar plants.
- Costs based on single or multiple train gasifier configurations - capacities up to ~ 2,800 MW



Hydrogen Production – Coal Gasification

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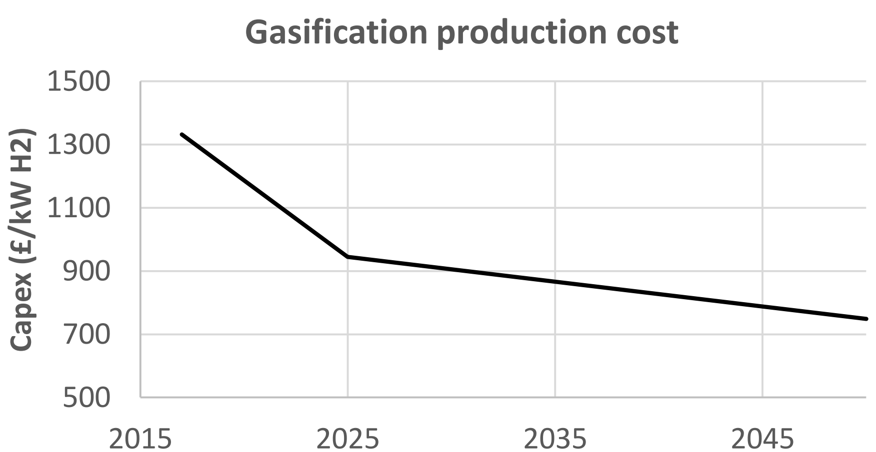
Cost-Time Curve CAPEX cost reduction assumptions (compared with today's technology)

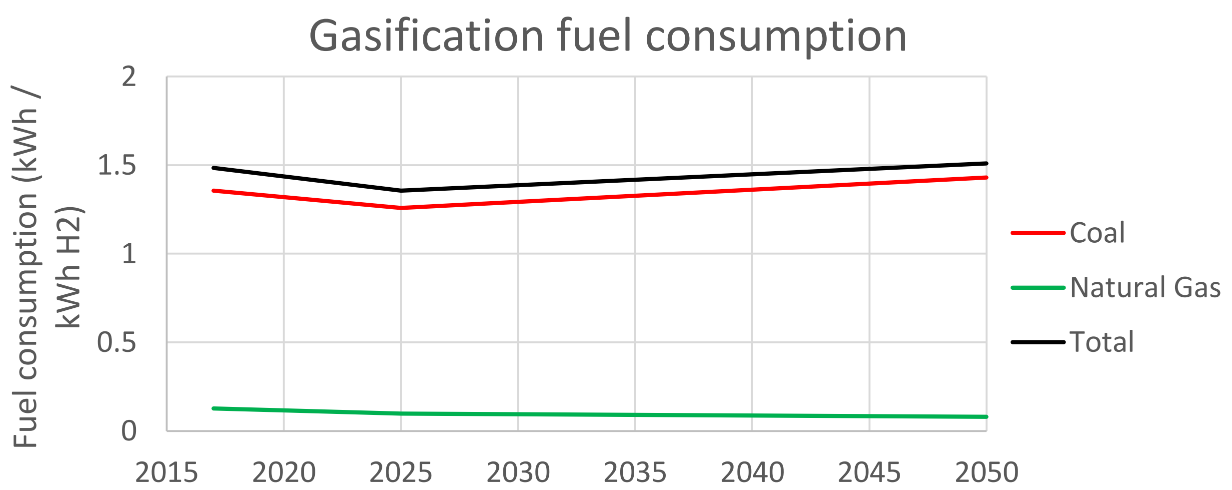
- It is predicted that over time the capital cost of coal gasification will decrease. There are a number of technologies being researched currently so it is not possible to say exactly what a plant in 2050 will look like though predictions are made of the cost reduction and potential technologies that may be implemented.

- Potential improvements for 2025:
  - Replace current gas clean-up and sulphur removal technologies with next generation technology
  - Improvement in capex, opex and efficiency through reduced parasitic power loads
- Potential improvements for 2050:
  - Second generation gasifier reduces capex
  - More active CO_2 removal solvent
  - More efficient and lower capex CO_2 compression



Cost-Time Curve Energy Consumption

- It is predicted that the focus of developments will be in reducing the capital cost rather than improving efficiencies as overall this will give the greater return.
- The predicted increasing trend in energy consumption is a result of the more capital efficient technology improvements, for example the replacement of the cryogenic Air Separation Unit with a membrane unit or another similar technology to be developed.
- Energy Consumption considerations include:
    - Coal as feedstock
    - Natural gas for power (@55% efficiency)



Summary: Key assumptions for Gasification

Gasification Capital Cost assumptions

- The Capex for different capacities:

Base Case £m	H2 Capacity kWth	Base Case £ / kW
£ 794	88,552	£ 8,969
£ 1,482	354,210	£ 4,184
£ 1,779	531,315	£ 3,348
£ 2,025	708,420	£ 2,858
£ 2,239	885,525	£ 2,528
£ 2,430	1,062,630	£ 2,287
£ 2,605	1,239,735	£ 2,101
£ 2,766	1,416,840	£ 1,952
£ 2,916	1,593,945	£ 1,830
£ 3,058	1,771,050	£ 1,727
£ 3,192	1,948,155	£ 1,638
£ 3,319	2,125,260	£ 1,562
£ 3,441	2,302,365	£ 1,495
£ 3,558	2,479,470	£ 1,435
£ 3,670	2,656,575	£ 1,382
£ 3,778	2,833,680	£ 1,333

- Future Capex costs:

	Year	2017	2025	2050
CAPEX	£M	£ 3,782	£ 2,891	£ 2,018
H2 Capacity	MW	2,840	3,060	2,693
System Cost	£ / kW	£ 1,332	£ 945	£ 749
Coal Energy	kWh / kWh H2	1.36	1.26	1.43
Thermal Energy	kWh / kWh H2	0.13	0.10	0.08

Coal Gasification

Additional information

- Footprint:
  - The US DoE H2A [1] study gives a requirement of 250 acres for a 246,478 kg/day coal gasification plant with CCS. This equates to 2.52 m^2 kW H_2 HHV
  - The US DoE H2A study gives a requirement of 50 acres for a 155,236 kg/day biomass gasification plant. This equates to 0.80 m^2 per kW H_2 HHV
- Water Consumption:
  - The US DoE H2A study gives a process water requirement of 0.286 litres/kWh H_2 HHV
- Emissions:
  - The amount of CO_2 captured is 17.1 kg / kg H_2 (0.43 kg CO_2 / kWh H_2 HHV) (@ 90% capture rate)
  - The amount of sulphur captured is 0.21 kg / kg H_2 (0.005 kg sulphur / kWh H_2 HHV)
- Purity:
  - The output purity and potential impurities of a coal gasification plant will be comparable with reforming.
- Turndown:
  - A coal gasification plant can be turned down to 70% of capacity at a rate of no more than 10% per day. As with reforming these plants should not be cycled up and down regularly (only seasonally). However, this constraint is relaxed in a fleet operation where the average load factor is lower than 70% during summer periods as some plants are shut down

(1) US Department of Energy - http://www.hydrogen.energy.gov/h2a_analysis.html

Gasification from bio feedstock

Bio feedstock

- Bio feedstock gasifiers are likely to be several orders of magnitude smaller than coal gasifiers.
  - Typically expect 49 – 473 MW HHV plant sizes.
  - Feedstocks can include almost any organic material including:
    - Purpose grown woody crops (e.g. short rotation beech)
    - Purpose grown herbaceous crops (e.g. grasses)
    - Agricultural waste
    - Commercial waste
    - Dry sewage waste
  - Feedstocks have been studied in a separate, parallel study on bioenergy pathways.
- The flow diagram for gasification will differ marginally depending on the feedstock due to the requirement to remove different compounds from each feedstock e.g. tars, sulphur, etc.
- Costs for bio gasification are provided by Ecofys from the Bio Energy Pathways project [1]

1 *Bioenergy Heat Pathways to 2050 Rapid Evidence Assessment, Ecofys & E4Tech (for BEIS), 2018 – pending publication*

Gasification from bio feedstock

Summary of data

- The data provided from Ecofys details two technologies:
  - Clean gasifier (59 – 473 MW H2 HHV) (for purpose grown feedstocks)
  - Waste gasifier (48 – 97 MW H2 HHV) (for waste feedstocks)
- The Waste gasifier is based on a technology currently being tested and developed in the UK.
- The advantage of gasification using bio feedstock is the neutral carbon cost of the feedstock, combined with CCS this has the potential for an overall negative carbon cost.
- The data provided has been adjusted to 2017 prices (clean gasifier costs are used as it is has lower capex) and converted to HHV.

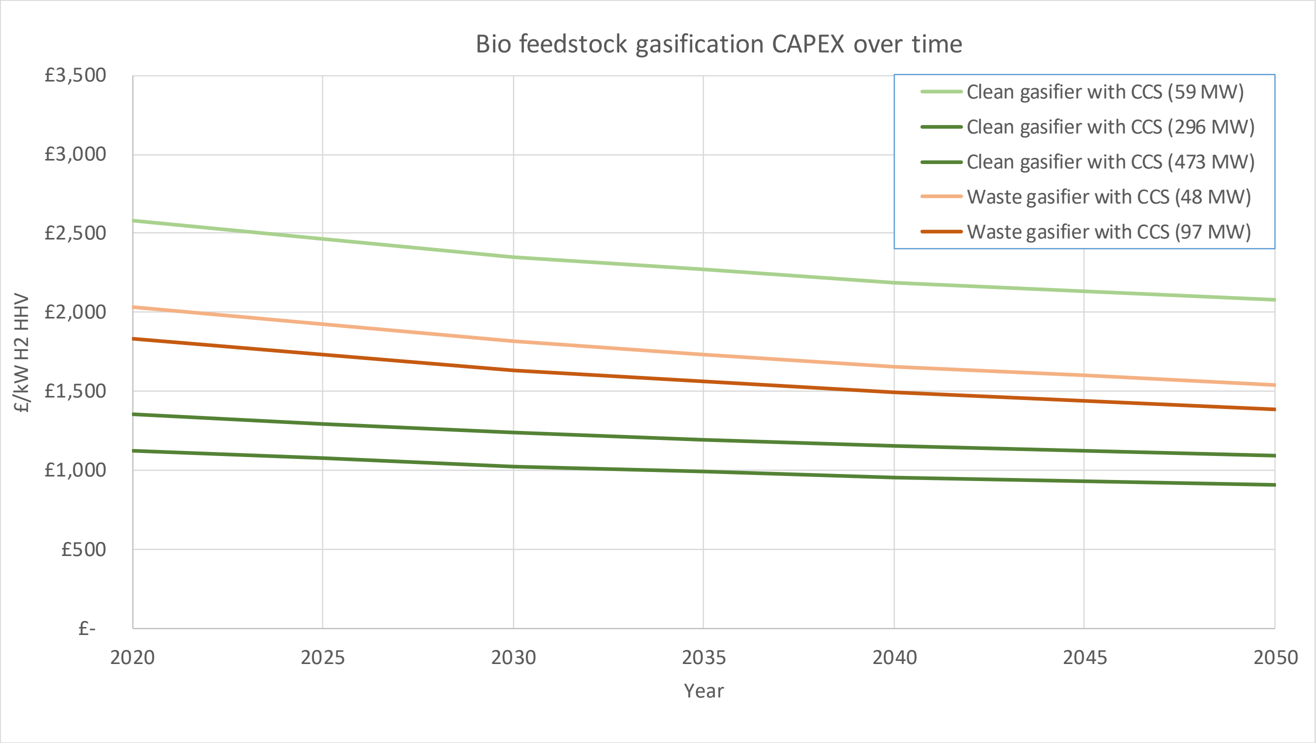
A sample of the data is shown below:

		2020	2025	2030	2035	2040	2045	2050
473 MW HHV Clean gasifier with CCS	Capex (£/kW H2 HHV)	£ 1,122	£ 1,073	£ 1,023	£ 988	£ 953	£ 929	£ 905
	Opex (£/kW H2 HHV/yr)	£ 105	£ 100	£ 95	£ 92	£ 89	£ 87	£ 84
	Conversion efficiency (MWh feedstock/MWh H2 HHV output)	66%	67%	67%	69%	69%	70%	70%
97 MW HHV Waste gasifier with CCS	Capex (£/kW H2 HHV)	£ 1,835	£ 1,735	£ 1,634	£ 1,563	£ 1,491	£ 1,439	£ 1,388
	Opex (£/kW H2 HHV/yr)	£ 355	£ 355	£ 335	£ 316	£ 302	£ 288	£ 278
	Conversion efficiency (MWh feedstock/MWh H2 HHV output)	85%	85%	85%	85%	85%	85%	85%

Gasification from bio feedstock

Bio feedstock

The graph shows the capex cost reduction over time as well as the cost reduction with scale for the Clean and Waste gasification technology.



- **Hydrogen Production**
  - Hydrogen Purity
  - Electrolysis
  - Reforming
  - Gasification
  - **Liquid hydrogen import**
  - Compression

Hydrogen Production - Import

Hydrogen import (from overseas)

- Currently, a small amount of hydrogen is imported into the UK in 20' and 40' liquid hydrogen containers, holding ~19,000 litres and ~42,000 litres of liquid hydrogen respectively.
- Liquid hydrogen has a volumetric density of ~53 kg/m^3 [2 MWh/m^3] compared with high pressure compressed (35 MPa) hydrogen at ~23 kg/m^3 [0.9 MWh/m^3].
- The challenge in moving liquid hydrogen is that it is a cryogenic liquid at -250°C (LNG is -160°C).
- The Hydro-Hydrogen Quebec project(1) (EQHHPP) studied the energy cost of producing and transporting hydrogen from Quebec, Canada to Hamburg, Germany.

SHIPS being built and planned by Kawasaki Heavy Industries to carry liquid hydrogen extracted from Victoria's brown coal could one day be operating out of the Port of Hastings. The top "test" vessel will carry 2500 cubic metres of liquid hydrogen and the larger vessel, below, is designed for 160,000 cubic metres.

- It found the cost to be £0.0915/kWh (to unload terminal) (from an initial energy feedstock of £0.0144/kWh), giving an effective 'surcharge' of importing hydrogen of £0.077/kWh based on 724 GWh/year supply.
- This is significantly higher than the LNG importation cost (see next slides).
- In Kobe, Japan the World's first liquid hydrogen import terminal is being built(2) by Iwatani and Kawasaki Heavy Industries. It is set to cost 10 billion Yen (~£70M) though there are no details on the capacity of the plant.
- To supply the Kobe terminal (3) permission has been granted to build LH_2 'test' tanker ships (*top of picture above*). These will ship liquid hydrogen from Australia to Japan, initially this is a 2,500 m^3 ship with plans for a 160,000 m^3 ship, this equates to 7 GWh and 398 GWh HHV of hydrogen respectively.

(1) – Hydro-Hydrogen Quebec - https://courses.engr.illinois.edu/npre470/web/readings/Status%20of%20the%20hydro-hydrogen%20pilot%20project%20(EQHHPP).pdf
(2) - Fuel Cells Works- https://fuelcellsworks.com/news/kawasaki-heavy-iwatani-to-build-hydrogen-import-hub-in-kobe
(3) - The Motor Ship - http://www.motorship.com/news101/ships-and-shipyards/first-liquid-hydrogen-carrier

Hydrogen Production - Import

Hydrogen import (from overseas)

- LNG import terminals, such as Milford Haven, Grain, etc. are likely to be the most similar plants to a liquid hydrogen import terminal.
- When offloading (importing) LNG it can be kept cold (and liquid) with insulation and liquid nitrogen cooling [liquid nitrogen is readily available and relatively low cost], in so maintaining the LNG in its liquid phase. Liquid hydrogen is significantly colder than liquid nitrogen so would require a more complex plant and higher energy consumption to re-liquefy the hydrogen should it partially evaporate. Therefore a combination of a cryogenic liquid tank and compressed gas storage would likely be combined at the import terminal.
- As there is no information on the cost of an LH2 import terminal the LNG terminal costs with a ‘complexity’ factor applied will be used.
- Based on a Chicago Bridge & Iron presentation(1) this gives a total capital cost, varying from £43/kW to £81/kW Natural Gas plant size (a £143 /kW outlier data point is excluded).
- Allowing for the additional complexity associated with hydrogen (factor of 1.66) this **gives an estimate for the unloading facility of £94/kW capital cost** (average of data points with complexity factor applied).
- However, given the current planned test ships are only carrying 7 GWh of hydrogen, and the 398 GWh ships are just design concepts, there is considerable uncertainty over the feasibility and the likely costs.
- Operating costs for LNG in **unloading and gasification are ~£29/GWh (2) and for storage ~£27/GWh/day(3)** . These numbers will be assumed for liquid hydrogen in the absence of any available hydrogen specific data.

(1) – LNG Import TerminalCost and Schedule Basics - https://www.scribd.com/document/259437215/LNG-Import-Terminal-Cost-and-Schedule-Basics
(2) - The LNG storage business and associated costs - Enagás Gas Assets General Management - http://www.gainnprojects.eu/?force_download=465
(3) - Macroeconomic Impacts of LNG Exports from the United States - https://energy.gov/sites/prod/files/2013/04/f0/nera_lng_report.pdf

Hydrogen Production - Import

Costs for Hydrogen Import

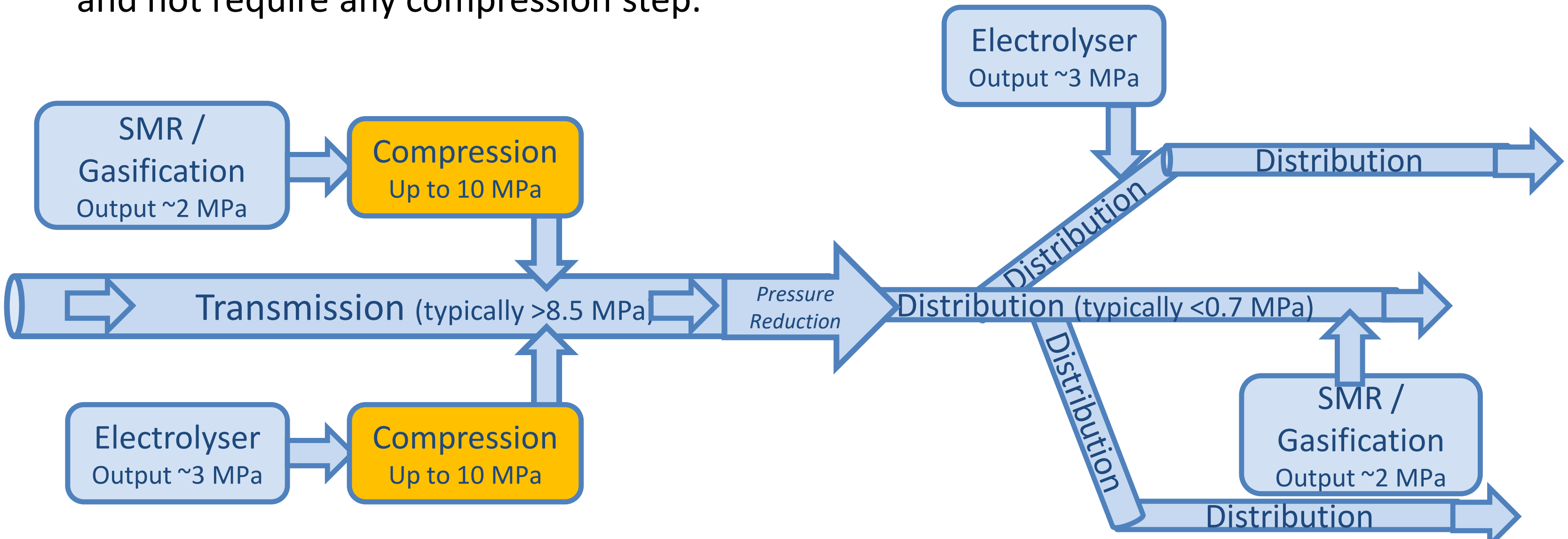
- The cost of import for LNG is around £1.65 ($2.15) per mcf equating to ~£6/MWh on top of the NG source price (pre-liquefication). Compared with the EQHHPP price for hydrogen of ~£77/MWh HHV cost on top of energy cost for hydrogen production. This large discrepancy suggests the EQHHPP price may be an over-estimate for large scale import.
- The costs of imported LNG are always going to be proportionally lower than LH_2. This is because H_2 has:
  - Typically higher cost of production vs. cost of extraction *(need very low cost power for H_2 production)*
  - double the liquefication energy cost (LNG 10% vs. LH_2 19.2%)
  - more complex engineering required (due to extreme temperature of LH_2 vs. LNG)
  - Higher energy density of LNG vs. LH2 (6.99 MWh/m3 vs. 2.79 MWh/m3)
- Thus an estimation of cost of LH_2 import cost based on LNG costs would be:
  - [£6/MWH + (double liquefication costs)] x [Reduction in energy density 'efficiency' of transport] x [complexity factor for LH2] = [6 + 3] x [6.99/2.79] x [1.66] = £37/MWh import cost.
  - This is half the EQHHPP cost though still significantly higher than LNG.
  - The **base case for the cost of import (i.e. over and above the cost of producing overseas) is estimated as £0.037/kWh, with a lower case of £0.023/kWh** (no complexity factor).
- Hydrogen import requires a sea port (same as LNG) which limits the regional nodes of deployment.
- A minimum plant size of 50 GWh/day import will be assumed. (Milford Haven LNG = 576 GWh/day)
- A plant of 50 GWh/day would have an estimated capital cost of £195M
- Based on these figures, hydrogen import would likely only be financially feasible (relative to production within the UK) with very low cost renewables overseas.
- The purity of liquefied hydrogen is very high as all contaminates are solidified due to the very low boiling point of the liquid hydrogen. Hydrogen sourced from liquid hydrogen is typically >99.9999% pure.

- **Hydrogen Production**
    - Hydrogen Purity
    - Electrolysis
    - Reforming
    - Gasification
    - Liquid hydrogen import
    - **Compression**

Hydrogen Production - Compression

Compression

- Compression will be required for each of the hydrogen production technologies discussed in this report to enable the hydrogen to be injected into the transmission system, which is assumed to operate at pressure up to 10 MPa.
- The compression step from Production to Transmission will have a capital, fixed operational and variable operational cost, where the variable operational cost is primarily electrical usage.
- Where hydrogen production is not centralised and instead localised near to the end use then it is assumed that the hydrogen will be fed directly into the low pressure distribution system and not require any compression step.



Hydrogen Production - Compression

Compression (from Production into Transmission)

Hydrogen production technologies typically output between 1.5 – 4 MPa, whereas the hydrogen transmission network is expected to require up to 10 MPa injection pressure. Therefore a compression stage is needed to boost the pressure up to ~10 MPa. (The exception is the future predictions for PEM Electrolysers that are expected to be able to directly inject without the need for additional compression).

The US Department of Energy has produced in-depth studies(1) on all aspects of a distributed hydrogen system as part of the H2A study and has also set targets(2) for hydrogen compression.

The H2A study is based on reciprocating compressors whereas the targets are based on newer centrifugal technology (this technology is not yet proven so is included as indicative of expert opinion of what is possible).

Other novel compression systems such as hydride based compression cycles and electrochemical systems have been proposed and are under development but costs and engineering details have not yet been produced and designs are not developed for this scale of system, hence they are not included in the analysis.

For each technology, a total installed capital cost and operating cost are calculated.

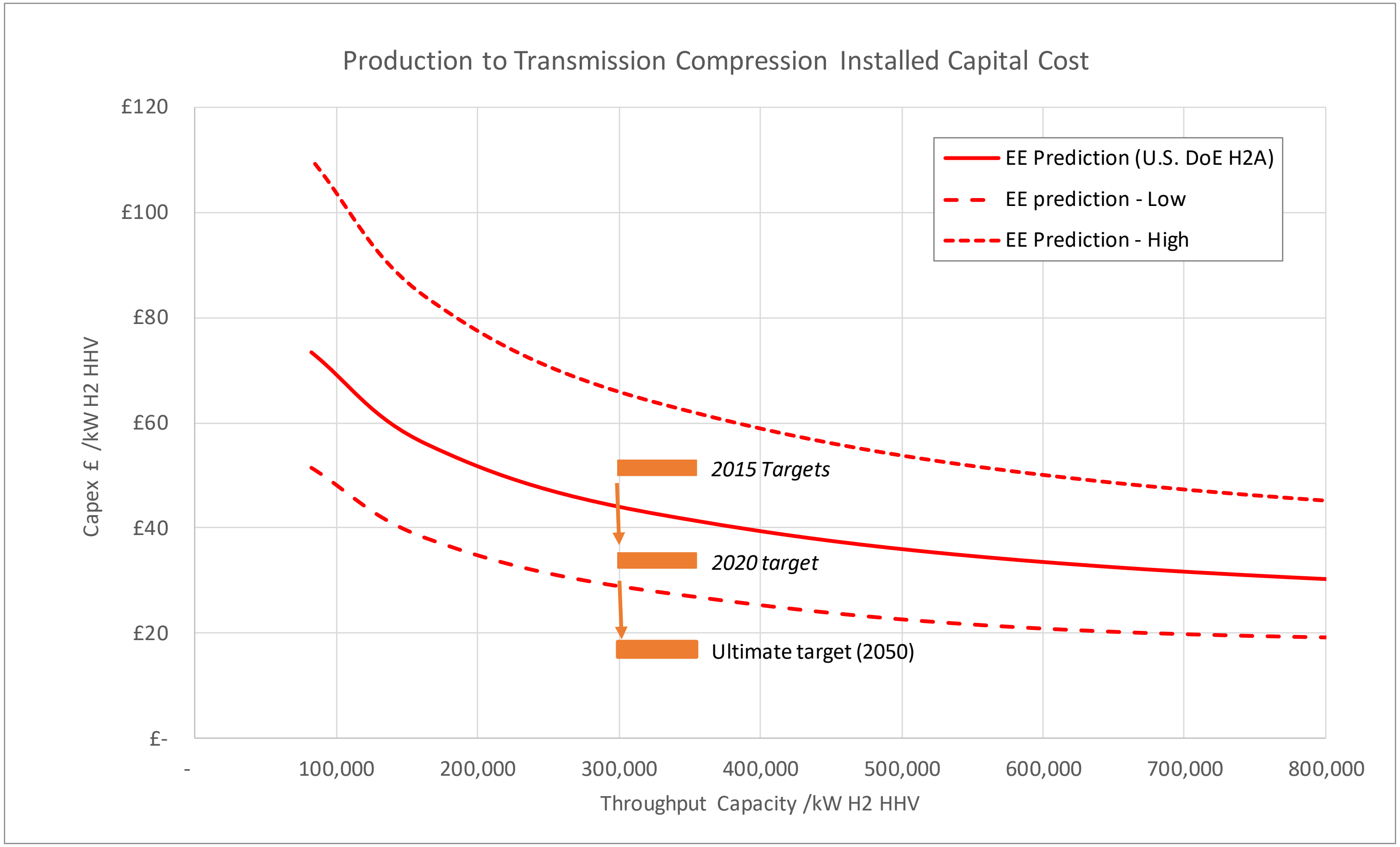
For BEIS analysis, the H2A data will be used as the baseline as this is based on industry supplied data from multiple sources, albeit in the US.

(1) US Department of Energy - http://www.hydrogen.energy.gov/h2a_analysis.html
(2) US Department of Energy - https://energy.gov/eere/fuelcells/doe-technical-targets-hydrogen-delivery

Hydrogen Production - Compression

Compressors

- The following base line and upper / low cases are proposed for the compressor capital costs:



Summary: Key assumptions for Post Production Compression

Compressors Scenario Summary

- The following table gives example compressor sizes and associated capital and operational costs which will be used in the analytical work:

Compression		kW H2 HHV	82,106	164,213	328,425	656,850	1,313,700
	CAPEX £ / kW H2 HHV	LOWER	£ 51.51	£ 38.06	£ 27.91	£ 20.30	£ 17.76
		BASE	**£ 73.44**	**£ 55.86**	**£ 42.51**	**£ 32.33**	**£ 24.54**
		UPPER	£ 110.16	£ 83.79	£ 63.77	£ 48.50	£ 36.81
	OPEX	Opex Fixed £ / kW H2 HHV	£ 6.57	£ 4.99	£ 3.79	£ 2.88	£ 2.18
		Energy Usage kWe / kW H2	0.0176	0.0176	0.0176	0.0176	0.0176

- This table shows whether a compressor is required or not for the production technologies when exporting to the transmission grid:

Compressor Required for Transmission injection?

Year / Technology:	2020	2025	2030	2035	2040	2045	2050
Electrolyser_PEM	YES	YES	YES	NO	NO	NO	NO
Electrolyser_Alkaline	YES	YES	YES	YES	YES	YES	YES
Electrolyser_SOE	YES	YES	YES	YES	YES	YES	YES
Reformers (SMR & GHR)	YES	YES	YES	YES	YES	YES	YES
Reformers (Future Tech)	YES	YES	NO	NO	NO	NO	NO
Gasification (All)	YES	YES	YES	YES	YES	YES	YES
Liquid Hydrogen Import	NO	NO	NO	NO	NO	NO	NO

- Overview of the project
- Hydrogen Production
- **Transmission**
- Distribution
- End Use
- Storage
- CCS

Hydrogen Transmission

Creating a hydrogen Transmission network

- It is assumed that an entirely new high pressure transmission pipeline network would be built to transport hydrogen to local distribution networks. It is further assumed (based on the H21 analysis) that the low pressure distribution of hydrogen would occur through the existing natural gas distribution system. Which would be converted to operate safely using hydrogen.
- It is likely that the hydrogen transmission pipelines would follow similar routes to the natural gas network as the connection / break out points would remain the same, and the pipeline would be largely subterranean.
- If the full conversion takes place, the existing high pressure natural gas transmission network would likely still be used in part for supplying industries which rely on methane as a chemical feedstock, plants using methane to produce hydrogen and electricity generation plants utilising CCS. Sections no longer required for natural gas could possibly be repurposed for hydrogen to give better resilience and/or improve linepack.
- Transmitting hydrogen requires a greater volumetric flow than natural gas, as the energy content per unit volume is around 1/3 that of natural gas (Hydrogen has 31% of the energy per unit volume of natural gas).
- The reduced energy density does not directly translate to requiring a three fold increase in flow. This is because the very small molecule of hydrogen flows far more easily than methane. Such that the energy flow rate for hydrogen is 71% that of natural gas. This can be compensated by either: a larger diameter pipeline, an increase in inlet pressure or accepting a larger drop in pressure through the pipeline. Realistically for the proposed hydrogen transmission system all three of these options will be utilised.

Hydrogen Transmission

Approach to sizing the pipes in a hydrogen transmission network

- A larger diameter pipeline
  - The Transmission dataset will contain a range of pipe diameters up to 48 inches (1.22 m).
  - For greater flows pipelines could be installed in parallel
- An increase in inlet pressure
  - An inlet pressures of 10MPa is being used for the analytical work as proposed by Jacobs
  - This has been flagged as higher than expected by a number of observers, who argue a lower pressure system is feasible, particularly for point to point lines as opposed to complete networks. Using the data currently assumed in this slide pack, the 10 MPa choice gives a lower ownership cost for the system.
  - Lifetime cost comparisons have been carried between the 10 MPa and 4 MPa pipelines. Although the 4 MPa would save on compression of the hydrogen prior to injection into the grid there would be higher capital costs which (using the assumptions in this slidepack) outweigh the operational cost benefits.
  - It was found for a 11.8 GW average flow and 413 GW peak and for a pipeline network of 7,623 km, the total lifetime cost was £25,908M vs £33,220M (10 MPa vs 4 MPa). This simple analysis supports Jacobs proposal of a transmission pressure of 10 MPa.
  - This design pressure for the network is an assumption which should be investigated in future more detailed iterations of the analysis.
- A larger drop in pressure through the pipeline.
  - With a higher inlet pressure there is a greater 'headroom' for a lower outlet pressure.
  - For a number of set transmission pipeline lengths, considered in the analytical work, the pressure drop and peak flow are calculated.
  - Each pipeline also ends in a compressor station, with capital, operational and energy costs linked to the pipeline section. The compressor boosts the pipeline pressure back to the inlet pressure of 10 MPa.
  - The exception to the joined pipeline and compressor plant is when a pipeline terminates as no pressure boost is required at the terminus and hence no compression plant is deployed.
- The approach taken to transmission system modelling is conservative and could lead to a small overestimation of the costs.

Hydrogen Transmission

Pipeline sizes and costs are defined between all feasible regions

- H_2 transmission pipelines are defined for a range of lengths, diameters and peak flow rates to reflect transmission between different regions of GB.
- Operating parameters of compression energy, available line pack storage and annual leakage losses are defined for each of these pipelines.
- Finally total investment and annual maintenance cost data is defined for the transmission pipelines for a range of distances.
- These cost and performance parameters are used to determine the investment and operational cost of building new transmission pipelines with different capacities between any two spatial regions.
- A new pipeline specification / standard will need to be created for hydrogen (e.g. lower permissible leak rate)
- Compression may be required to recompress the flow back to the inlet pressure, incurring additional capital, fixed operational and energy costs.
- Leakage is assumed to be 0.5% of the total system flow (following Ofgem methodology) and can be considered as an inefficiency of the pipeline.

Hydrogen Transmission

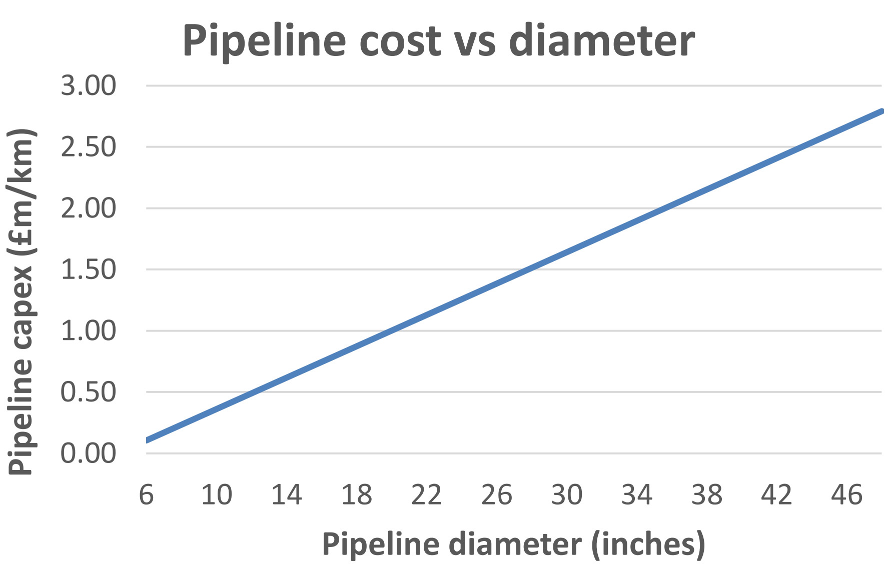
Summary data

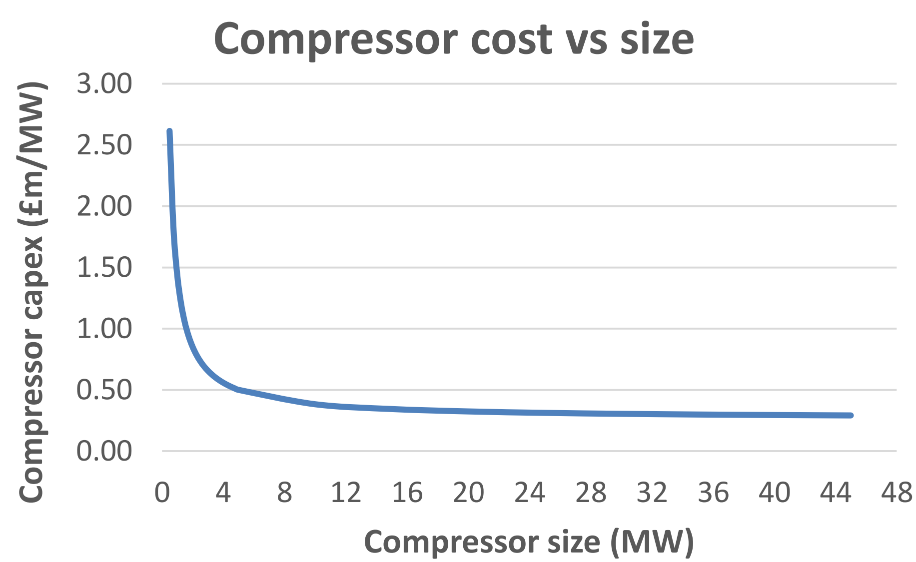
- The capital cost of pipeline[1] and compressors[1] are calculated as

$$Pipeline\ cost\ (£m/km) = 0.064\ x\ Pipeline\ diameter\ (inches) - 0.2799$$

$$Compressor\ cost\ (£m) = 0.3114\ x\ Compressor\ size\ (MW) + 1.3869$$

- The annual fixed opex is calculated as 5% and 15% of pipeline and compressor capital cost respectively





1 Jacobs internal data

Hydrogen Transmission

Capital Cost Scenarios

- To understand the sensitivity of the Transmission pipeline costs on the overall conversion an upper and lower cost scenario is provided.
- The Lower / Upper capex cost will be -15% / +35% of the Base value.

Footprint

- The majority of the pipeline would be underground so once installed the land is still useable for purposes such as agriculture and transport. This land would not be available for occupied buildings. The land take would be similar to today's natural gas transmission system.
- The safety distance (the distance from the pipeline to a location of adequately low probability of harm) for natural gas is primarily due to the radiative heat from an ignited leak.
- The distance increases with pressure and pipeline diameter.
- Burying the pipeline reduces the distance very significantly.
- Hydrogen has a very low radiative heat, though the higher pressure, higher flame temperature and lower ignition energy will all determine the actual distance for each pipeline.
- As estimation of the likely area of uninhabited space required for the pipeline is 0.02 km^2 / km of pipeline.

- Overview of the project
- Hydrogen Production
- Transmission
- **Distribution**
- End Use
- Storage
- CCS

Distribution

Bottom up analysis of existing distribution network infrastructure

- The repurposing of the distribution network is assumed to be performed for a whole spatial region when it has a demand for hydrogen for heat / industrial processes as part of the roll-out of hydrogen for heat around the country.
- Data on gas distribution network at National/Gas Distribution Network (GDN)/Local Distribution Zone level has been used, where available, to determine the total existing gas network infrastructure including:
  - High Pressure, Intermediate Pressure, Medium Pressure and Low Pressure pipelines
  - Ancillary infrastructure equipment
- This was compared to the gas consumption and the number of MPRNs (Meter Point Administration Number) by consumer type to determine parameterisation metrics of existing network infrastructure
- This relationship was then used to estimate the likely extent of infrastructure within regions where data has not been available from the relevant GDN
- The cost of this conversion will depend upon the following key elements of the local distribution network:
  - Existing network infrastructure (length of pipelines (km), size of pipelines (inches), compressors, district governors etc.)
  - Share of infrastructure that needs upgrade / replacement by individual component
  - Cost of upgrade / replacement of each infrastructure component

Distribution

High level approach to quantifying the re-purposing activity

The approach to quantifying the extent of network re-purposing activity in a particular local distribution zone is summarised in the flow diagram:

Local distribution zone

ONS / BEIS data on number of gas meters at high spatial resolution is available for this task.

Define ‘area types’ – urban, peri-urban and rural, e.g. based on gas meter density

Divide the LDZ into areas (e.g. local authorities) and assign an ‘area type’ to each.

Agglomerate areas of similar area type into nodes, e.g. **3-4 nodes per LDZ**

The approach to quantifying the number of solutions required will depend on data availability

Frequency of re-purposing activity per 1,000 meters, in each area type

Total amount of re-purposing activities in node

Unit cost of each re-purposing activity in each area type

Total cost of network re-purposing in node

Distribution

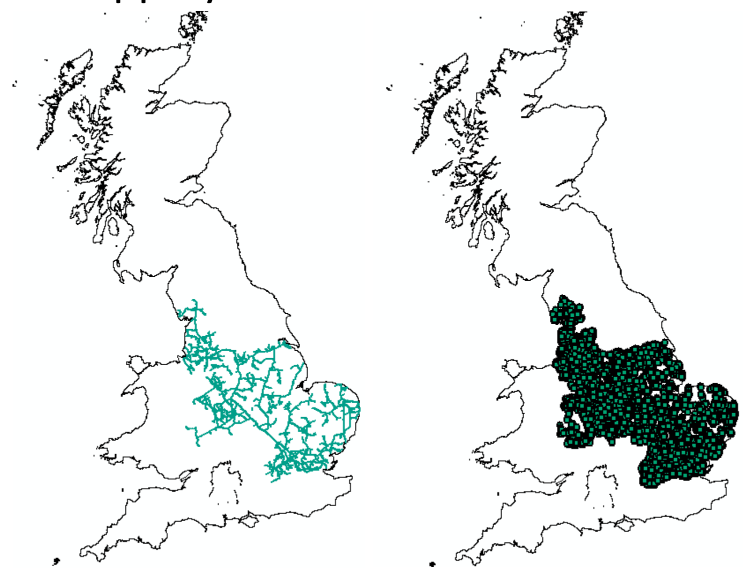
Determining frequency of re-purposing activity in each area type

Approach:

There are a number of approaches to quantifying the number of re-purposing activities, depending on the level of data available, in particular the network data available from the GDNOs.

- In the case that detailed network data is available from a GDNO, it is possible to directly 'count' the number of components requiring re-purposing within the conversion area.
- As such detailed data has only been available for a sub-set of GDNOs, we have used network data for the available LDZs to establish the average frequency of re-purposing requirements in each area type, which can then be applied to other LDZs.

Local Transmission System pipe layout **Locations of flow measurement equipment**



Data provided by Cadent (National Grid) for this project

Distribution

Characterisation of the gas distribution network

Data on the composition of the UK gas distribution network, in terms of the split between pressure tiers, pipeline diameters and pipe materials, has been gathered from Transco (1999), the long-term development statements of the gas distribution network operators (GDNOs) and data provided directly by the GDNOs.

Breakdown of the gas distribution network by pressure tier and by materials incompatible with hydrogen:

Split of < 7 bar network by pressure tier (% of total network length)	
% of UK gas pipelines that are Intermediate Pressure	1%
% of UK gas pipelines that are Medium Pressure	13%
% of UK gas pipelines that are Low Pressure	86%

Fraction of network that are iron or steel (% of total network length)	
Average Proportion of Whole Mains Pipeline Network that are Iron (%)	47%
Average Proportion of Whole Mains Pipeline Network that are Steel (%)	8%

The Iron Mains Replacement Programme is already replacing iron mains with plastic pipes, which are expected to be compatible with hydrogen, for safety reasons and will continue irrespective on any future conversion of the networks to hydrogen. This programme is expected to conclude around 2032.

Steel was previously exclusively used for pipelines >0.7MPa. However, reinforced thermoplastic pipe is more frequently being used for pressures up to 2MPa, which results in a reduction of costs.

Trials to test pipe suitability are expected to be performed as part of the H21-NIC project[1].

[1] H21-NIC, https://www.ofgem.gov.uk/system/files/docs/2018/01/ngn_h21_nic_submission_final.pdf

Distribution

Requirement for network re-purposing activities

The requirement for network replacement or re-purposing activities is defined either as the % of network length that needs to be addressed or on the basis of number of activities per customer meter. Data on the length of network and number of customer meters in a particular region can then be used to quantify the total requirement for network repurposing activities.

- Base case assumptions for the proportion of the network requiring replacement following completion of the Iron Mains Replacement Programme (IMRP):

% of mains requring replacement post IMRP	
% of Iron mains that will require replacement	5%
% Steel Pipelines that will require replacement	100%

- In addition to pipeline replacement, other mains are expected to require reinforcement and various other replacement or reinforcement actions are expected to be required:

Requirement for network reinforcement (% of length within each tier)	
Estimated % of Intermediate pressure pipelines reinforced	0.00%
Estimated % of Medium pressure pipelines reinforced	0.42%
Estimated % of Low pressure pipelines reinforced	0.00%

Based on analysis in the Leeds H21 study

- In addition further reinforcement calculation is made based on the loss of linepack in the distribution system.

Additional re-purposing actions		Assumption / source
% of District governors requiring replacement	25%	Based on Leeds H21 study
Number of district governors per meter	1.14E-04	Based on Leeds H21 study
Number of Low integrity components per District Governor	3	Based on Leeds H21 study
No. of gas detectors per meter	2	Based on Leeds H21 study
Number of isolations required per meter (installation of double block and bleed assembly)	3.48E-03	Based on Leeds H21 study

Source: Leeds City Gate H21, http://www.northerngasnetworks.co.uk/archives/document/h21-leeds-city-gate

Distribution

Requirement for network replacement by region

- The amount of network requiring replacement post IMRP by region has been derived using the data on the total distribution pipeline length by region and the network assumptions shown on the preceding slides:

	Total Length of All Pipeline Mains in 1999 (km)	Length of Iron Mains in 1999 (km)	Estimated Iron Mains requiring Replacement after IMRP (km)	Length of Steel Mains in 1999 (km)	Estimated Steel Mains requiring Replacement (km)
Scotland	13447	6384	319	1043	1043
South East	27040	14377	719	1155	1155
Southern	20864	8337	417	2230	2230
South West	18187	7335	367	2478	2478
Wales North	3171	1211	61	372	372
Wales South	10199	3894	195	1197	1197
Northern	18053	9035	452	1384	1384
North East	16807	8869	443	638	638
West Midlands	23305	14810	741	1612	1612
North West	34198	15779	789	1725	1725
Eastern	21132	10238	512	1341	1341
East Midlands	27834	12037	602	2055	2055
North Thames	22375	12452	623	857	857

- 100% of the iron mains requiring replacement are assumed to be within the low pressure tier
- Steel pipeline is assumed to be split between pressure tiers in the same proportions as overall network length is split between the tiers. In the base case, 100% of steel pipeline is assumed to require replacement post IMRP.

Source: Jacobs

Distribution – Cost assumptions for key network re-purposing activities

Costs of network re-purposing

- Pipeline replacement and reinforcement cost assumptions are tabulated below[1]:

Pipeline replacement / reinforcement costs	Cost	Assumption / source
Cost of replacing Low Pressure Iron / Steel Pipelines (£ / km)	£200,000	Assuming 127mm (5") pipe
Cost of replacing Medium Pressure Iron/ Steel Pipelines (£ / km)	£350,000	Assuming 229mm (9") pipe
Cost of replacing Intermediate Pressure Iron / Steel Pipelines (£ / km)	£400,000	Assuming 268mm (10.5") pipe
Cost of reinforcing Low Pressure Pipelines (£ / km)	£200,000	Assuming 127mm (5") pipe
Cost of reinforcing Medium Pressure Pipelines (£ / km)	£350,000	Assuming 229mm (9") pipe
Cost of reinforcing Intermediate Pressure Pipelines (£ / km)	£400,000	Assuming 268mm (10.5") pipe

- Costs of other network replacement or reinforcement activities are tabulated below[1][3]:

Cost assumptions for additional network re-purposing activities		
Cost of replacing District Governors (£ / district governor)	£	50,000.00
Cost of installing isolations (£ / isolation)	£	4,420.00
Cost of selective pressure testing (£ / km)	£	800.00
Cost of replacing District Governors (£ / meter)	£	5.68
Cost of installing isolations (£ / meter)	£	15.40
Cost of Gate Metering Station with Odourisation (£ / meter)	£	2.98
Cost of replacing low integrity components (£/ meter)	£	0.10
Cost of network survey (£ / meter)	£	1.89
Long-run average total cost for domestic gas meter (£ / meter)	£	151.43
Long-run average total cost for non-domestic gas meter (£ / meter)	£	2,477.23
Long-run average total cost for gas detector (£ / detector)	£	68.34
Cost Gas Meter Fittings (£ / meter)	£	50.00
Cost of Labour for Fitting Appliances (All Meters & Detectors) (£ / hour)	£	25.00

- Additional 0.7 MPa pipe is assumed to be required to compensate the reduction in linepack in the <0.7 MPa system as a result of hydrogen's lower volumetric energy density. The additional cost is calculated based on the following assumptions:

Cost of additional 7 bar pipe to compensate loss of linepack	
Useable Linepack Factor, F	0.6
Delivery pressure as proportion of maximum operating pressure	90%
Diameter of additional pipeline required due to linepack reduction (mm)	650
Cost of additional 7 bar pipeline (£/km)	£1,097,368

(1) Leeds City Gate H21, http://www.northerngasnetworks.co.uk/archives/document/h21-leeds-city-gate
(2) SPON's mechanical and electrical services price book, edited by Aecom, 46th ed., 2015
(3) https://sierrainstruments.com/shop/store_front.php?family_id=4&stock

JACOBS Consultancy

Hydrogen Distribution – Base Case cost breakdown for the entire gas distribution network

Repurposing Category	Total CAPEX	%	Cost Rank
Replacing Domestic Gas Meters - excluding installation	£3,519,494,101	15.9%	1
Labour and Fittings for Installation of Domestic Gas Meters	£3,486,179,700	15.7%	2
Replacing Gas Detectors - excluding installation	£3,176,745,981	14.3%	3
Replacing Low Pressure Steel Pipelines	£3,109,431,439	14.0%	4
Additional 7 bar Pipeline Required due to Reduction in Linepack Energy	£2,450,921,086	11.0%	5
Labour and fittings for installation of detectors	£2,349,256,700	10.6%	6
Replacing Low Pressure Iron Pipelines	£1,072,444,558	4.8%	7
Replacing Medium Pressure Steel Pipelines	£798,362,558	3.6%	8
Replacing Non-Domestic Gas Meters - excluding installation	£622,699,078	2.8%	9
Reinforcing Low Pressure Pipelines	£444,934,981	2.0%	10
Installing Isolations	£361,856,721	1.6%	11
Replacing Medium Pressure Iron Pipelines	£275,355,671	1.2%	12
Replacing District Governors	£133,480,494	0.6%	13
Replacing Intermediate Pressure Steel Pipelines	£103,171,634	0.5%	14
Gate Metering Station with Odourisation	£70,000,000	0.3%	15
Labour and Fittings for Installation of Non-Domestic Gas Meters	£62,842,250	0.3%	16
Reinforcing Medium Pressure Pipelines	£47,343,413	0.2%	17
Conducting Network Survey	£44,493,498	0.2%	18
Replacing Intermediate Pressure Iron Pipelines	£35,583,952	0.2%	19
Selective Pressure Testing	£14,468,898	0.1%	20
Replacing Low Integrity Components	£2,402,649	0.0%	21
Replacing Domestic Iron and Steel pipe	£0	0.0%	22
Reinforcing Intermediate Pressure Pipelines	£0	0.0%	22
Total	**£22,181,469,362**	**100.0%**	

Distribution – Assumptions for Scenarios

Scenario assumptions (1/2)

- There is considerable uncertainty in the costs of repurposing the distribution system
- Key questions include whether all gas meters need to be replaced, whether new detectors are needed at district governors/meter enclosures and the amount of pipes requiring replacement due to a risk of more severe leaks when using hydrogen compared to natural gas.
- In addition, there are practical questions about how the network can be maintained and faults can be remedied on a day to day basis. Until these are resolved, it is not possible to commit to the conversion of the network. For example, live working on a leaking hydrogen pipe would not be permitted whereas it is with natural gas (e.g. due to very low ignition energy of hydrogen and its invisible flame).
- These uncertainties will be inherent to any analysis of the hydrogen option for heat for some time to come (future studies are expected to investigate these issues, but it will be several years before the evidence is published).
- Given this is the case, we recommend using scenarios to reflect the range of uncertainty in the need for repurposing / replacement of different components when modelling distribution network repurposing costs (see next slide).
- Rather than modelling the absolute worst case where a critical safety issue is identified resulting in the whole hydrogen for heat program being abandoned, we have attempted to represent the feasible range of costs which could be incurred in any practical transition (i.e. for obvious reasons we do not attempt to include the "not possible" scenario which is in reality a worst case given the level of uncertainty we currently have over the safety issues).

Distribution – Assumptions for Scenarios

Scenario assumptions (2/2)

- Four scenarios are offered: (Jacobs) Base case, Lower, Upper and (Element Energy) Best.
  - The Base case is Jacobs' best estimate of what they believe the cost to be.
  - The Lower and Upper cases reflect the potential range over which the Base case could vary.
  - The Element Best case takes Jacobs' Lower case and removes detector and meter costs
- The range of assumptions are tabulated below:

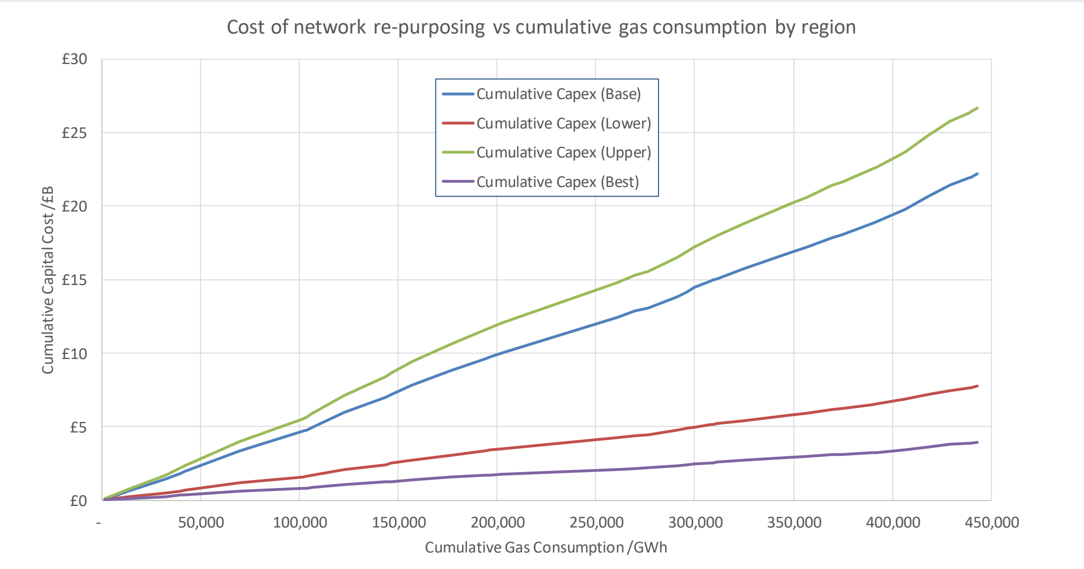
Deployment ranges	**Jacobs (base)**	**Jacobs (lower)**	**Jacobs (upper)**	**Element (Best)**
Percentage of iron/steel pipelines to be replaced	100%	50%	150%	30%
Percentage of reinforcing pipelines to be replaced	100%	50%	150%	30%
Percentage of District Governors to be replaced	100%	70%	150%	70%
Number of isolations required	100%	70%	150%	70%
Percentage of Domestic and Commerical Gas meters to be replaced	100%	20%	100%	0%
Number of Gas Detectors to be installed /meter	100%	20%	100%	0%
Percentage of additional pipeline for linepack / intermediate ring main	100%	70%	150%	70%
Percentage of selective pressure testing required	100%	70%	150%	70%
Percentage of low integrity components replaced	100%	70%	150%	70%
Percentage of additional Pipeline Required due to Reduction in Linepack / Intermediate 'ring main' installed	100%	70%	150%	70%

- The percentage increase / reduction of the requirement for each activity can be considered in two ways:
  - A percentage change in the number of items that require conversion
  - Or, a reduction in the likely cost for all items
- E.g. Domestic meters (lower band) only 2 in 10 meters require swap out (e.g. due to leak tightness of model) or this is equivalent to 20% of predicted cost per meter (=£32/meter) equivalent to a recalibration (rather than replacement) being needed at each meter point.

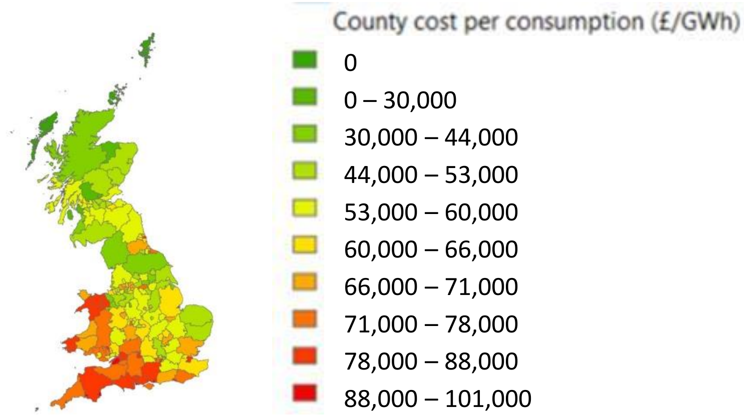
Distribution

Cost of network re-purposing at LA level

- Costs of re-purposing the distribution network have been calculated at the local authority (LA) level as described in the preceding slides.
- The Jacobs base case gives a 'street' (upstream of the meter) cost of conversion capital cost of ~£950 per meter. This is in good agreement with the Isle of Man conversion (as quoted in H21) of about £1,200 per property.
- Note that the lower bound requires that a solution is found which requires minimal meter replacement and no additional hydrogen detectors for each home.



Base case cumulative cost versus cumulative gas consumption



Mapping of re-purposing cost in terms of £ per GWh of gas consumption

- Overview of the project
- Hydrogen Production
- Transmission
- Distribution
- **End Use**
- Storage
- CCS

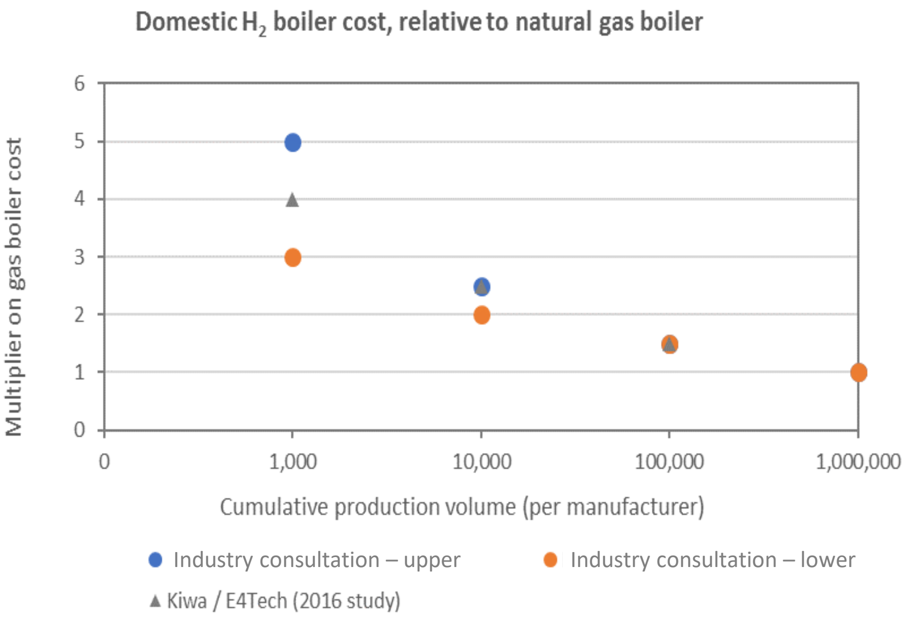
End-use appliances – domestic boiler replacement

Domestic boiler costs and installation

Domestic conversion costs

- Feedback from industry consultation and the Kiwa / E4Tech[1] study are in close agreement on the cost-volume curve for H_2-ready boilers relative to current gas boiler costs.
- The hydrogen boiler price tends to the gas boiler price as manufacturing volumes increase over 100,000 units per manufacturer per year.
- Refurbishment of existing boilers is not expected to be possible – different controls, gas valve, burner types etc.
- It may be possible to develop a hydrogen ready boiler which runs (with reduced efficiency) on natural gas while waiting for the transition. This would require certainty that the transition will occur.
- Pipework inside the home is a critical part of the transition – no work has been done on this to-date. If large amounts of pipework in existing homes needs replacement this has the potential to add very high costs to the program.
- Figures quoted are prices for appliances and installation costs (excluding tax)

Cost data



Installation time/cost

- **H21 project estimated 4.5 hrs to 13.5 hrs**, depending on type of boiler, at a cost of £208 to £625 per house.
- Installers / fitters will all need training in H_2 – additional training costs

[1]https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/537594/30686_Final_Report_DECC_Hydrogen_appliances_08.07.16.pdf

End-use appliances – domestic boiler replacement

Domestic boilers – additional characteristics

Efficiency

- The expectation is that H_2-boilers can achieve high efficiencies, similar to those of current natural gas boilers.
- This would only be confirmed during the required research and development phase of commercialisation.
- Higher burning temperature can lead to NOx formation – performance may be influenced by the NOx specification (low NOx requirements could push down efficiency and may require an exhaust catalyst).

Lifetime and maintenance

- H_2 boilers are expected to achieve 10-15 year target lifetimes (i.e. similar to current natural gas boilers)
- There may be some additional service requirements, hence O&M costs are expected to be higher.
  - Catalytic components (if required) would need to be replaced within 15 year lifetime
  - Regular servicing of the appliance may need to be mandatory if components such as exhaust catalysts are needed to ensure performance of the unit is maintained.

R&D and development timescales

- Industry consultation suggested a 3-5 year development process to achieve a first generation product (1,000 units). A further 3 year development cycle required to achieve the next generation product (100,000th unit).
- This process would be required across all units offered by the manufacturer – e.g. a manufacturer may have multiple heating cells, all of which would need this work (across domestic and commercial boiler lines).
- Early cost estimates of low hundreds of millions for full conversion of all lines (per manufacturer) have been indicated.

Critical point – at present boiler manufacturers use many shared components world wide – to develop UK only appliances may not be commercially viable without investment.

End-use appliances – commercial boiler replacement

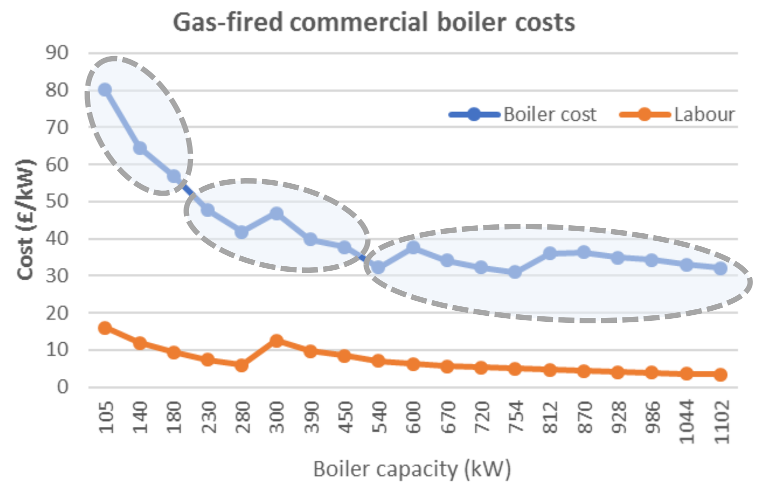
Commercial boilers

- The commercial boiler market spans a wide range of technology capacities, from light commercial (50-150 kW) to large-scale commercial (> 1MW-scale).
- Cost multiples for commercial-scale boilers were provided by the Kiwa/E4Tech study (2016), for the lower bound and from industry consultation as the Upper bound as follows:

Production volumes – light commercial (up to 150 kW)	Cost (x nat-gas tech) - LOWER	Cost (x nat-gas tech) - UPPER
10	4	8
100	2.5	6
1000	1.5	3.5

Production volumes – large commercial – floor standing (<880kW)	Cost (x nat-gas tech) - LOWER	Cost (x nat-gas tech) - UPPER
10	10	10
100	2.5	7
1000	1.5	4

- The larger commercial boiler market is characterised by low annual volumes. As a result, recouping the hydrogen boiler development costs in the commercial sector represents a significant commercial challenge, potentially requiring greater levels of public support.



Commercial boiler costs based on SPON's mechanical and electrical services price book (2015)

- Based on the SPON's price curve, we have identified three boiler size ranges, which can be characterised by a typical natural gas boiler cost:
  - 100-200 kW 65 £/kW
  - 200-500 kW 45 £/kW
  - > 500 kW 35 £/kW
- Hydrogen boiler costs with volume are defined as multiples of these typical natural gas technology costs.
- Installation costs are in the range 5-15 £/kW.

DECC Desk study on the development of a hydrogen-fired appliance supply chain, Kiwa / E4Tech, 2016
SPON's mechanical and electrical services price book, edited by Aecom, 46th ed., 2015

End-use appliances – End user pipework upgrades

Cost of replacement of internal gas pipework

- Internal pipework on the customer side of the gas meter, i.e. between the meter and gas appliances, may need re-purposing to carry hydrogen.
- Typically this pipework is copper and is sized to ensure that adequate gas flow rates can be provided to each of the gas appliances, while maintaining acceptable pressure drops along the pipes.
- The length of pipe runs will be very variable between buildings and pipe sizing dependent on the number of gas appliances.
- For domestic properties, an allowance of £500 /dwelling has been made. Based on SPONS price book, this is sufficient for just over 30m of 32mm diameter pipe, which can carry adequate gas supply for gas appliances of >50kW combined input capacity.
- There will be huge variability in the length and required sizing of internal pipework in the commercial stock. Many small commercial buildings will be similar to domestic properties, whereas large commercial buildings are likely to require much higher flow rates (larger pipes) and involve longer runs. Estimated allowances for internal pipework in commercial buildings are as follows (related to the boiler capacity)
  - 100-200 kW £ 1,000
  - 200-500 kW £ 2,000
  - > 500 kW £ 5,000

Table 1 Approximate flow of gas (m^3/hour) in straight horizontal copper tube

Tube size (mm)	Length of pipe run (m)							
	3	6	9	12	15	20	25	30
10 x 0.6	0.84	0.56	0.51	0.36	0.31	0.22	0.17	0.14
12 x 0.6	1.52	1.01	0.84	0.82	0.67	0.51	0.39	0.33
15 x 0.7	2.9	1.9	1.5	1.3	1.1	0.95	0.92	0.88
22 x 0.9	8.7	5.8	4.6	3.9	3.6	2.8	2.6	2.3
28 x 0.9	18	12	9.4	8	7.2	6	5.4	4.8

Flow rates are for low-pressure supplies with 1mbar differential pressure between ends of pipe for gas of relative density 0.6.

Add 0.3m for each 90° bend and 0.5m for each elbow or tee fitted to the actual length of the tube to obtain the total effective length.

Internal copper gas supply pipe sizing table – required pipe diameter as a function of gas flow rate and length of pipe run

Installed polyethylene natural gas pipe costs (SPON's price book, 2015)

Item	Net Price £	Material £	Labour hours	Labour £	Unit	Total rate £
NATURAL GAS: PIPELINES: MEDIUM DENSITY POLYETHYLENE – YELLOW						
Pipe; laid underground; electrofusion joints in the running length; BS 6572; BGT PL2 standards						
Coiled service pipe						
20 mm dia.	1.44	1.62	0.37	9.69	m	**11.31**
25 mm dia.	1.89	2.13	0.41	10.73	m	**12.86**
32 mm dia.	3.12	3.52	0.47	12.31	m	**15.83**
63 mm dia.	11.87	13.40	0.60	15.71	m	**29.11**
90 mm dia.	15.58	17.59	0.90	23.56	m	**41.15**

Source: SPON's mechanical and electrical services price book, edited by Aecom, 46th ed., 2015

Summary: Key assumptions for boiler cost and performance

Domestic boiler assumptions

- The Base Case assumptions for domestic-scale boilers are tabulated below.

Parameter	Base case value
Boiler cost	£2,500 (@10,000 UPM) £1,500 (@ 100,000 UPM) £1000 (@ 1,000,000 UPM) (An average NG domestic boiler costs £850)
Hydrogen ready hybrid boiler	Assume same cost and installation cost as standard boiler though only requiring 1hr for switchover.
Installation cost	£425 per household based on SPONS £625 Upper cost scenario (H21)
Internal gas pipework cost	£500 per household (including materials & labour)
Maintenance cost	£120/year (1.5x uplift in NG boiler contract)*
Efficiency	94% (assume same as NG boiler)
Lifetime	12 years (assume same as NG boiler)

* - Maintenance increase is based on industry consultation as a catalyst may need periodically changing.

Commercial boiler assumptions

- The Base Case assumptions for commercial-scale boilers are tabulated below.

Parameter	Base case value
Boiler cost	£350 – 650/kW (@100 UPM) £53 – 100/kW (@ 1,000 UPM) Based on commercial NG boiler cost range of 35-65 £/kW
Installation cost	£2,250 (100-200 kW) £2,500 (200-500 kW) £3,750 (>500 kW)
Internal gas pipework cost	£1,000 (100-200 kW) £2,000 (200-500 kW) £5,000 (>500 kW)
Maintenance cost	£2 – 5/kW (1.5x uplift on NG maintenance cost)
Efficiency	94% (assume same as NG boiler)
Lifetime	12 years (assume same as NG boiler)

- Commercial covers the majority of businesses, including schools, offices, hotels, SMEs, shops, etc.

The reduction in costs through volume would differ if there were other countries also converting to hydrogen.

Summary: Scenarios for boiler replacements

Domestic and Commercial boiler ranges

- Estimations are made of how many boilers, pipework, etc. are required to be changed for each MPRN:

Domestic	Lower	Base	Upper
Boiler Conversions required	100%	**100%**	100%
Boiler Costs (at final production scale)	£850	**£1,000**	£1,000
Installations cost for Hydrogen Boiler	£425	**£425**	£625
Total installation cost for HyReady Boiler	£475	**£475**	£675
Time saving for HyReady Boiler during switch	7.5 hrs	**7.5 hrs**	11.5 hrs
Internal gas pipework conversions required	0%	**100%**	100%

  - A natural gas boiler will not run on hydrogen therefore 100% of systems will require conversion either in advance to a HyReady/HySwitch hybrid boiler, or at the time of switch over.
  - Internal pipework may all require conversion (base & upper case) for safety considerations, or may be adequate in all properties (lower case).

Commercial	Base	Lower	Upper
Boiler conversions required	100%	100%	100%
Installations (directly linked to above)	100%	100%	100%
Internal gas pipework conversions required	100%	0%	100%

  - A boiler designed for both natural gas and hydrogen (HyReady/HySwitch) boiler would likely have higher NOx emissions than a natural gas only or hydrogen only boiler.
  - *All other assumptions for domestic appliances are carried over to the commercial appliances*

Summary: Assumptions for other domestic appliances

Other Domestic Appliances

- In addition to boilers in the home there are other appliances such as hobs, ovens and decorative fires consuming natural gas. These appliances would need converting as well.
- There is ongoing debate as to whether these appliances would be converted to currently available electrical equivalent appliances in order to save the high costs of new product development.
- The costs and effort hours per appliance are listed below. These are taken from the H21 study and represent the best data currently :

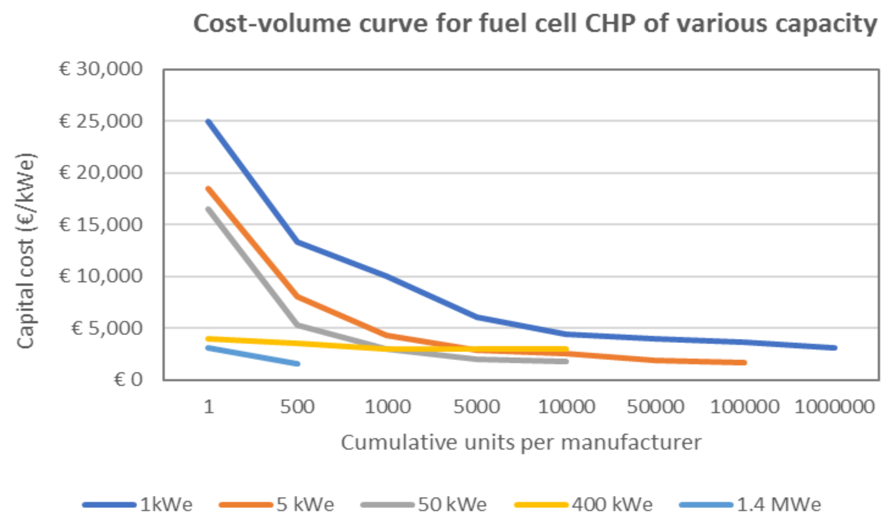
Type	Hardware	Unit Cost £	Effort hrs
Cookers	Traditional hob	750	13.5
Cookers	Traditional grill/oven	450	4
Heaters	Traditional gas fire (complex)	450	5

- Internal pipework has been included as a cost to each household as the existing natural gas pipework may not be compatible with hydrogen. For example: high leak rates, incompatible metal components, etc.
- For all appliances where hydrogen is combusted the NOx emissions will need to be carefully considered. For boilers (the highest cumulative demand in-house appliance) it may be an absolute requirement for catalytic combustion to ensure low NOx.

End-use appliances – Fuel cell CHP

Fuel cell CHP

- The EC Fuel Cell and Hydrogen Joint Undertaking (FCH JU) commissioned an authoritative study into the commercial prospects of fuel cells in CHP applications – the 'Roland Berger study'.
- The study provides cost-volume curves for fuel cell CHP systems across a range of sizes, including:
  - Capex and stack replacement costs
  - Installation costs
  - O&M costs
- Efficiency and lifetime projections were also included.
- Note that the Roland Berger data is based on natural gas-fired systems. It also does not distinguish between PEM and SOFC systems.
- Modification of Roland Berger costs is required to account for the direct hydrogen fuel supply.



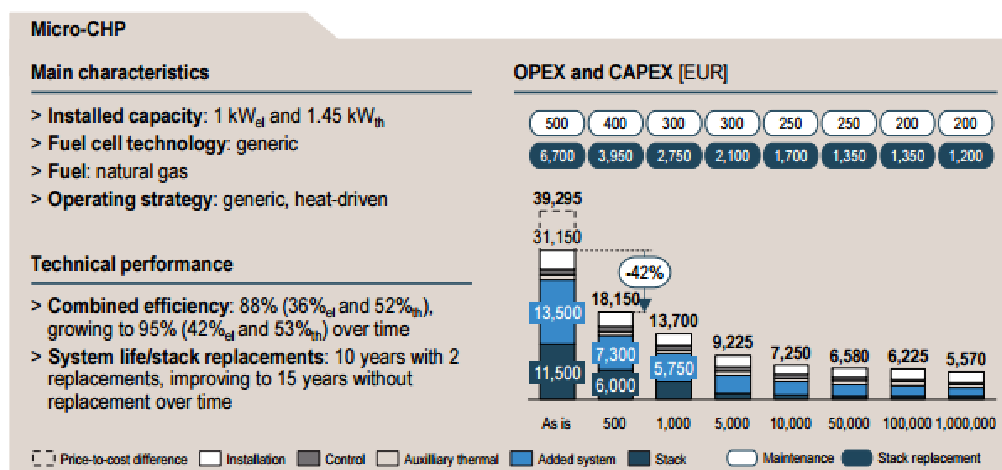
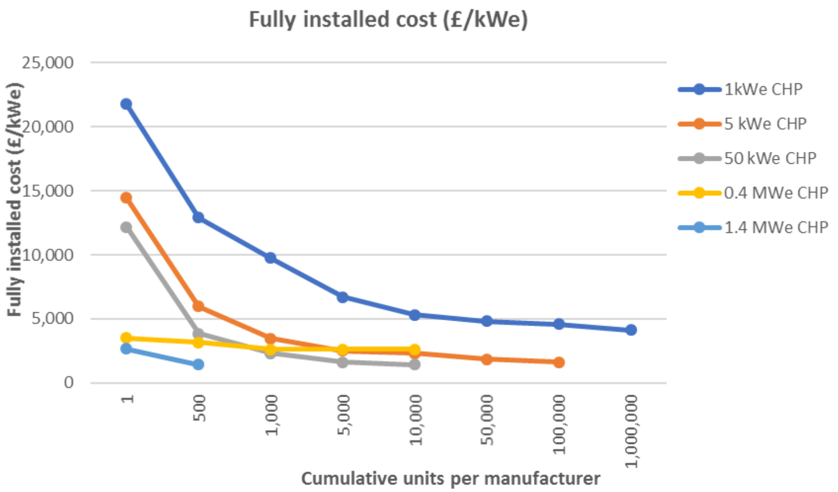


Figure 38: Technology and cost profile of generic fuel cell integrated mCHP[64]

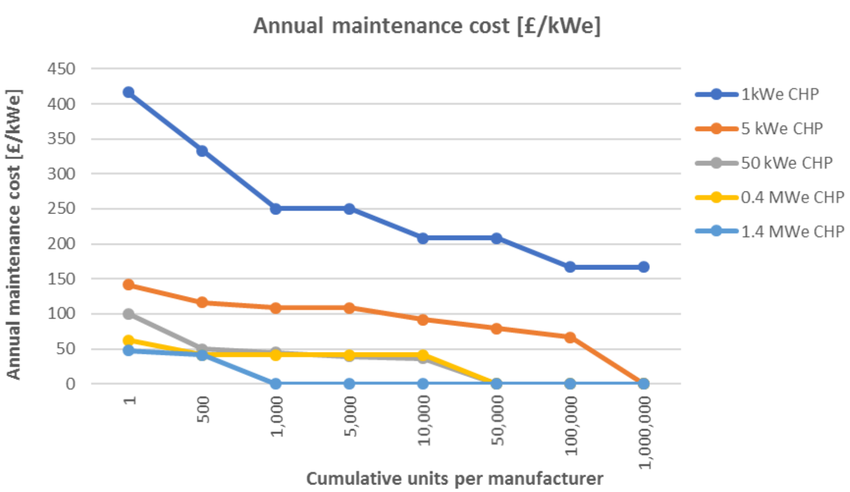
Roland Berger analysis of capex and opex for fuel cell mCHP at a range of production volumes

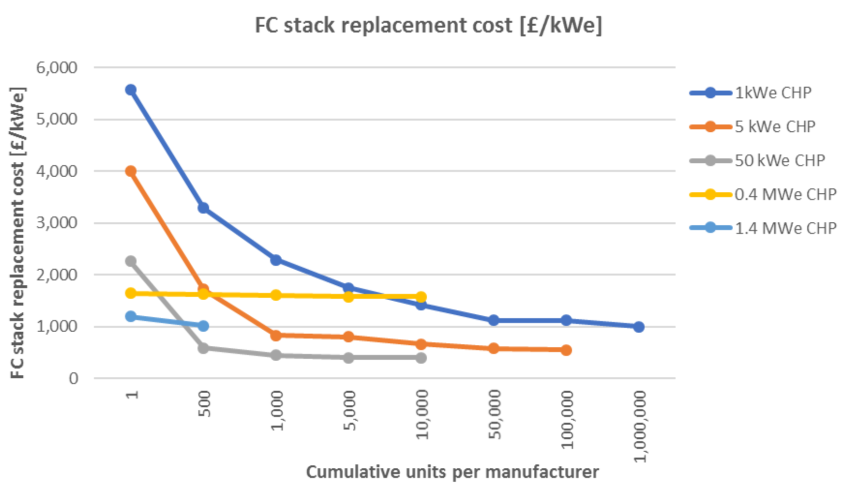
End-use appliances – Fuel cell CHP cost assumptions

Fuel cell CHP – base case cost assumptions



- Base case cost assumptions for fuel cell CHP systems are shown in the charts.
- Costs are based on Roland Berger figures, converted to GBP and corrected for the avoided reformer cost.





End-use appliances – Key fuel cell CHP cost data

Fuel cell CHP – cost data

- The capital and annual maintenance cost forecasts with cumulative units installed per manufacturer (UPM) are tabulated below.

Capital cost variation with manufacturer experience

Fully installed cost (£/kWe)					
UPM	1kWe CHP	5 kWe CHP	50 kWe CHP	0.4 MWe CHP	1.4 MWe CHP
1	£21,792	£14,433	£12,173	£3,500	£2,642
500	£12,908	£5,957	£3,833	£3,167	£1,417
1,000	£9,750	£3,469	£2,292	£2,625	-
5,000	£6,688	£2,490	£1,600	£2,625	-
10,000	£5,302	£2,289	£1,433	£2,625	-
50,000	£4,831	£1,842	-	-	-
100,000	£4,583	£1,625	-	-	-
1,000,000	£4,124	-	-	-	-

Annual maintenance cost variation with manufacturer experience

Annual maintenance cost [£/kWe]					
UPM	1kWe CHP	5 kWe CHP	50 kWe CHP	0.4 MWe CHP	1.4 MWe CHP
1	£417	£142	£100	£63	£48
500	£333	£117	£50	£42	£42
1,000	£250	£108	£45	£42	-
5,000	£250	£108	£39	£42	-
10,000	£208	£92	£37	£42	-
50,000	£208	£79	-	-	-
100,000	£167	£67	-	-	-
1,000,000	£167	-	-	-	-

End-use appliances – additional fuel cell CHP assumptions

Additional fuel cell CHP assumptions

- A range of further assumptions important for the evaluation of fuel cell CHP cost and performance are tabulated below:

Current assumptions:

Parameter	1 kWe FC mCHP		5 kWe CHP	50 kWe CHP	400 kWe CHP	1.4 MWe CHP
	PEM	SOFC				
Electrical efficiency, % (HHV)	30%	42%	42%	45%	45%	41%
Thermal efficiency, % (HHV)	44%	31%	31%	27%	27%	26%
Stack lifetime (years)	3.33	3.33	5	3.33	4	4
Auxiliary boiler efficiency % (HHV)	95%	95%	95%	95%	95%	95%

At technology maturity

Parameter	1 kWe FC mCHP (100,000 UPM)		5 kWe CHP (50,000 UPM)	50 kWe CHP (10,000 UPM)	400 kWe CHP (10,000 UPM)	1.4 MWe CHP (1,000 UPM)
	PEM	SOFC				
Electrical efficiency, % (HHV)	35%	51%	51%	51%	51%	51%
Thermal efficiency, % (HHV)	45%	30%	30%	30%	30%	30%
Stack lifetime (years)	15	15	10	10	10	10
Auxiliary boiler efficiency % (HHV)	95%	95%	95%	95%	95%	95%

- Efficiencies are largely taken from the FCH JU fuel cells in distributed generation study (Roland Berger)[1]. These values are based on generic fuel cells (i.e. an average across competing fuel cell technologies in the size cluster).
- In the case of mCHP, values are given separately for PEM and SOFC fuel cell systems, as the performance of current products based on the two technologies differ significantly.
- Note that the efficiencies in the Roland Berger study are based on natural gas fuelled technology and therefore may be conservative when considering pure H_2 fuelled systems. However, particularly in the case of high temperature fuel cells, the integration of waste heat from the exhaust in the reformation process may mean the electrical efficiency of a hydrogen-fuelled system is not significantly higher

1: Advancing Europe's energy systems: Stationary fuel cells in distributed generation, FCH JU, Roland Berger, 2015

2: Braun, Klein & Reindl, Journal of Power Sources, 158 (2006), 1290-1305

End use – Industrial Demand

Industrial conversion

- There is very little data on the potential cost and feasibility of converting industrial users' processes from natural gas to hydrogen.
- Industry consultation confirmed that although the gas usage is considerably higher than domestic/commercial the number of users is much smaller so there are more bespoke or low volume solutions
- Due to bespoke nature of users conversion costs could very easily escalate.
- Leeds H21(1) established that in their study area non-domestic meters accounted for 37% of the usage (2.3 TWh annual) but only 1% of the connections, corresponding to 3,126 meter points. Of these, there were only 127 industrial customers, but accounted for 67% of non domestic consumption (1.57 TWh/y).
- Leeds H21 categorised industrial users in their sample area and gave conversion cost estimates in the table to the right:

Category	Change	Conversion Cost per kW Gas Capacity	Installed kW Thermal	Conversion Cost
Commercial > 70 kW (from MSOA Data)	Boiler (costed on basis of 200 kW sites)	£150.00	600,000	£90,000,000
Process Boiler (from NGN Data)	New burner	£50.00	27,000	£1,350,000
Space Heating (from NGN Data)	New boiler	£100.00	291,000	£29,100,000
CHP* (from NGN Data)	New turbine	£1,000.00	56,000	£56,000,000
Glass (from NGN Data)	New furnace	£1,000.00	44,000	£44,000,000
Process (from NGN Data)	New burner	£250.00	111,000	£27,750,000
			Total	£248,200,000

Table 5.10. *Estimated Costs for the Conversion of Industrial and Commercial Equipment to Hydrogen*

(1) – Leeds H21 - http://www.northerngasnetworks.co.uk/archives/document/h21-leeds-city-gate

Summary: Key assumptions for Industrial Demand End Use costs

Industrial conversion summary

- The following assumptions for industrial end-use costs have been identified for use in analysis:

	Conversion Cost per kW installed
Process Boiler	£ 150
Space Heating	£ 50
CHP	£ 850
Glass	£ 1,000
Process	£ 250

- Overview of the project
- Hydrogen Production
- Transmission
- Distribution
- End Use
- **Storage**
- CCS

Hydrogen Storage

Types of Storage

- Hydrogen storage included in the dataset falls into two categories:
  - Centralised storage
  - Distributed storage
- Centralised storage involves very large volumes stored seasonally or strategically.
  - For seasonal storage the volume would be filled during months of low demand (summer) and then emptied into the Transmission system during times of high demand (winter). This storage allows the production capacity of the whole hydrogen system to be sized based on the average monthly demand rather than the peak monthly demand.
  - Salt caverns would provide the majority of this storage, though Imported Liquid Hydrogen could also provide additional storage at Import Terminals (akin to LNG Import Terminals).
- Distributed storage would be situated close to the high demand locations to help supply any localised peak demand. This is most likely to be intra-day rather than intra-seasonal.
  - Linepack storage in the transmission system
  - Large above ground vessels / tanks
  - Line packing in the distribution network

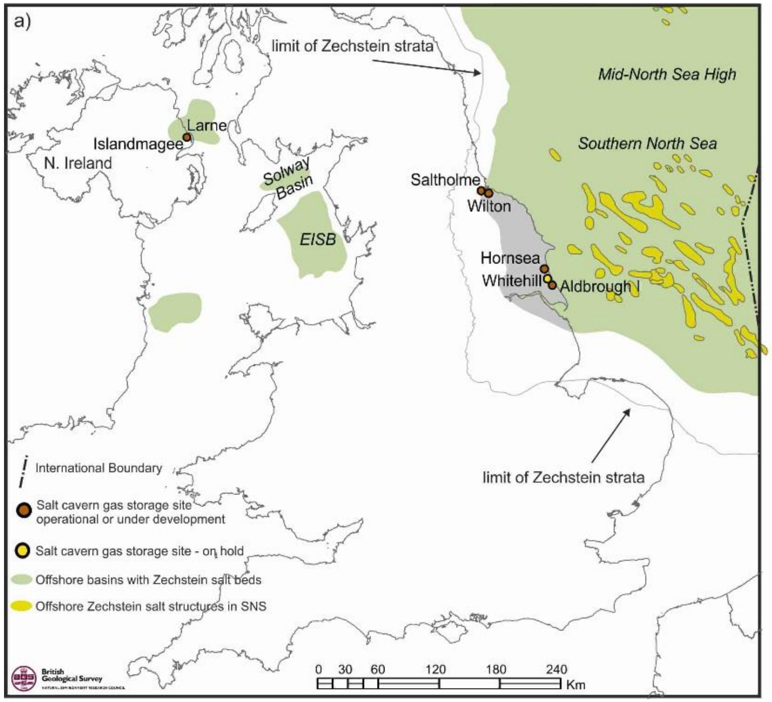
Hydrogen Storage - Centralised

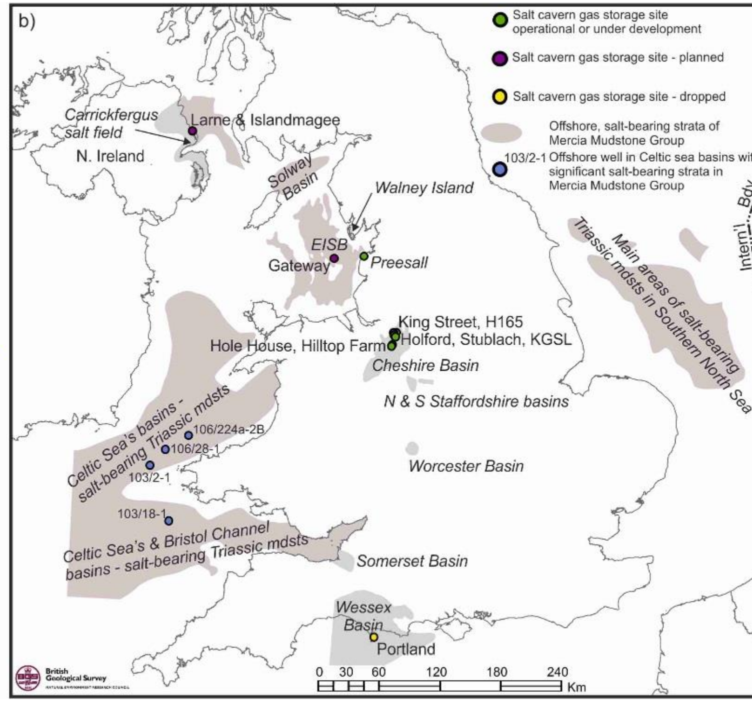
Salt Cavern Storage

- Salt caverns are commonly used for storage of a range of gases. Caverns in the Tees Valley have been used for hydrogen storage in the past.
- Constructed in massive bedded halites
- Halite beds of two main ages
  - Triassic (youngest) & a number of halite beds – Northwich & Preesall halites are the most important
  - Permian – oldest & two main sequences
    - Boulby Potash – youngest and thinnest (Teesside area)
    - Fordon Evaporites – oldest and thickest (Scarborough and south to the Humber)
- Some salt basins cannot be considered due to
  - Salt basins being too small
  - Salt beds being too thin
  - Salt beds being too shallow
  - Salt beds containing too high levels of insoluble (non-salt rock)
- Depleted hydro-carbon (oil or gas) fields are deemed not suitable for hydrogen storage due to the residual contaminants e.g. sulphur compounds, hydrocarbons, etc.

Hydrogen Storage – Centralised

UK salt fields and salt cavern gas storage sites





Permian salt-bearing basins – mainly:

- Boulby Halite (Teesside) and Fordon Evaporites (Aldbrough & Hornsea gas storage) in eastern England
- Permian salt beds in N. Ireland (Islandmagee Gas Storage & Larne CAES project)
- Major potential exists in southern North Sea – large diapiric salt structures & potentially close to major pipeline routes

Triassic salt-bearing basins – mainly:

- Northwich Halite (Cheshire Basin)
- Preesall Halite (NW England [Preesall] & East Irish Sea [Gateway Gas Storage project])
- Dorset Halite in southern England proposed as storage formation (Portland Gas Storage) – but not developed

Hydrogen Storage - Centralised

Main salt cavern storage potential

Main potential for H_2 salt cavern storage exists in:

- Triassic salt basins
  - Cheshire Basin – already a number of gas storage sites both operational and under development
  - Wessex/Dorset Basin
  - Offshore, East Irish Sea – one proposed gas storage site
  - Larne Basin, N. Ireland – previously considered for gas storage but deeper Permian halites deemed of better quality
- Permian salt basins
  - Eastern England – in both Fordon Evaporite and Boulby Halite formations
  - Possibly Larne, N. Ireland – small area and already best known area of salt being proposed for gas and compressed air storage facilities
  - Offshore in Southern North Sea

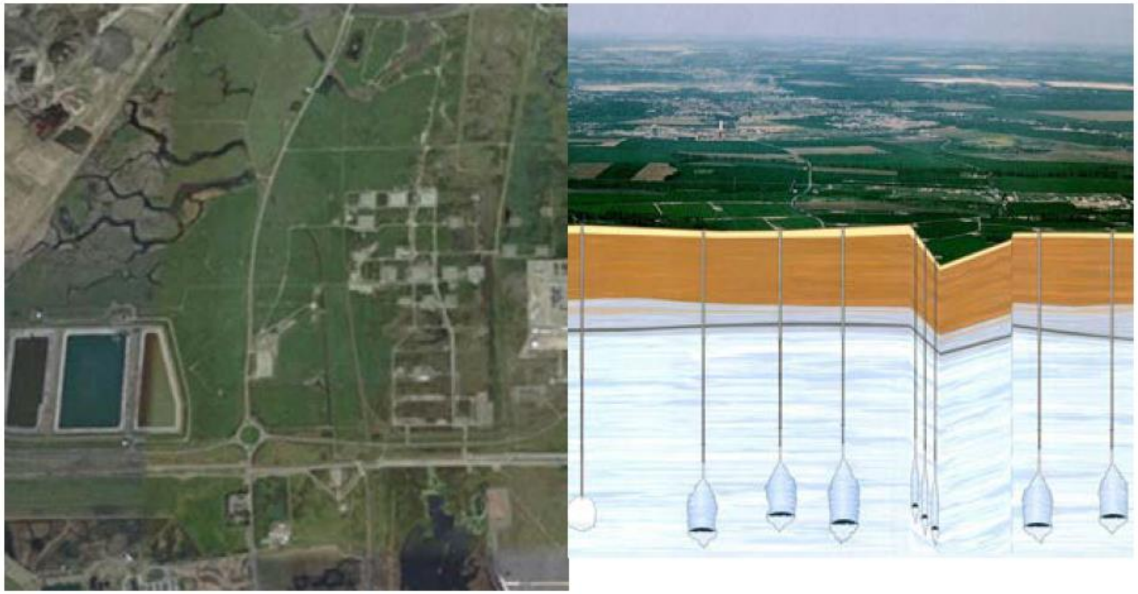


Image 2.11. *Teesside and East Riding Underground Gas Storage*

Hydrogen Storage - Centralised

Salt Caverns

- Of the potential areas for salt cavern storage, the following have been selected for detailed analysis:
  - Wessex/Dorset
  - Cheshire
  - East Yorkshire
  - Off-shore – East Irish Sea
- Data on salt cavern storage is based on previous ETI studies on the cost and potential of using salt caverns for H2 storage and more recent data from British Geological Survey (BGS).
- In the absence of cost data for Dorset/Wessex it is assumed that the costs will be the same as Cheshire Basin.
- BGS have provided an estimate of the potential storage in each region based on 0.001% of land use.
  - The 0.001% estimate is already very close to current storage already present in some regions so Element Energy have provided a Higher scenario of more available storage based on comparison with existing storage and estimated potential for expansion.
- From the ETI reports and BGS data capital and operating costs per GWh stored and per GW discharge are calculated

Hydrogen Storage – discharge rates

Salt Caverns

- Salt caverns can be used for intra-day, daily, weekly, or seasonal operation. However, there are physical attributes of the caverns that dictate the maximum discharge rates.
- The main criteria is the cavern wall stability and to maintain this the pressure must be kept within 30% to ~80% of lithostatic pressure and the rate of change of the gas pressure must be limited.
  - Lithostatic pressure is the natural pressure within the surrounding rock (salt), this pressure increases the deeper you go, so the deeper the cavern the higher the potential operating pressure.
  - The difference in stored volume between 80% and 30% of lithostatic pressure is defined as the working volume of the cavern.
- If the cavern pressure was to exceed the lithostatic pressure it could cause fractures in the surrounding rock, if the pressure dropped to low it could cause the cavern to implode – each of these could potential result in loss of containment of the hydrogen and irreparable damage to the cavern.
- If the cavern pressure is cycled to quickly it can cause a number of problems including spalling (fragmentation) of the cavern.
- High withdrawal rates can cause excessive velocity of the gas exiting the cavern causing damage to the tubing and hanging strings – this is a potential problem in any pipe flow.
- The maximum discharge rate is defined by the maximum rate of change of the pressure within the cavern and varies slightly with each cavern design, depth, etc. However, the ETI report generalises this rate to be a maximum 10% of the contained volume per day, as long as the minimum / maximum lithostatic pressure boundaries are respected (and this is the approach used in our dataset).
- This constraint is included within the cost of storage i.e. for every kWh of hydrogen storage, 10kWh of salt cavern storage is costed and no additional constraints on discharge are imposed
- The cost of processing the hydrogen is included within the charge / discharge costs

Summary: Key assumptions for Hydrogen Storage (Centralised)

Salt Caverns

- The following table summarises the maximum available storage scenarios (dark blue headings) and then capital and operating costs.

	Typical maximum working pressure (assume to be 0.8 litho pressure) MPa	Nos. Caverns (0.001% & >100m)	Volume (actual) m3	BGS 0.001% estimate of potential storage GWh	EE estimate of potential storage GWh	Capex £/GWH stored	Fixed Opex £/GWh/y stored	Variable Opex £/GWh	Capex £/GW discharge	Fixed Opex £/GW/y discharge	(H2 used in process) Inefficiency	Electrical usage kWh/GWh H2 HHV
Cheshire Basin	10.5	16	12,226,409	424	4,237	£1,763,946	£67,298	£419	£6,732,618	£256,861	0.838%	50
East Yorkshire	27.0	52	65,481,385	5,836	58,356	£1,403,377	£79,570	£637	£44,397,966	£2,517,314	0.419%	61
East Irish Sea (offshore)	10.5	78	93,410,622	3,237	32,373	£1,763,946	£100,965	£419	£7,069,249	£404,629	0.838%	50
Wessex	27.0	220	255,024,135	22,727	227,273	£1,763,946	£67,298	£419	£44,397,966	£2,517,314	0.838%	61

Hydrogen Storage – Line Packing methodology

Modelling of Line Packing storage

- The term linepack is used for all pipelines to refer to the gas ‘stored’ in a pipe.
  - By dropping the outlet pressure additional gas is made available from the pipeline
  - This pressure drop happens when demand exceeds supply (out vs. in)

- There is significant linepack storage available in the current natural gas transmission system. Linepack in the distribution system is limited.

- For sizing (costs & duration) the effective linepack is calculated for the entire distribution system.
  - This is not for the purposes of modelling it as an available storage technology
  - Instead it is used as a proxy calculation for the amount of reinforcement pipeline that would be required to maintain the same availability of supply for hydrogen as that of natural gas.

Source: Jacobs Consultancy notes

Hydrogen Storage – Line Packing methodology

Approach to calculation of Line Packing storage

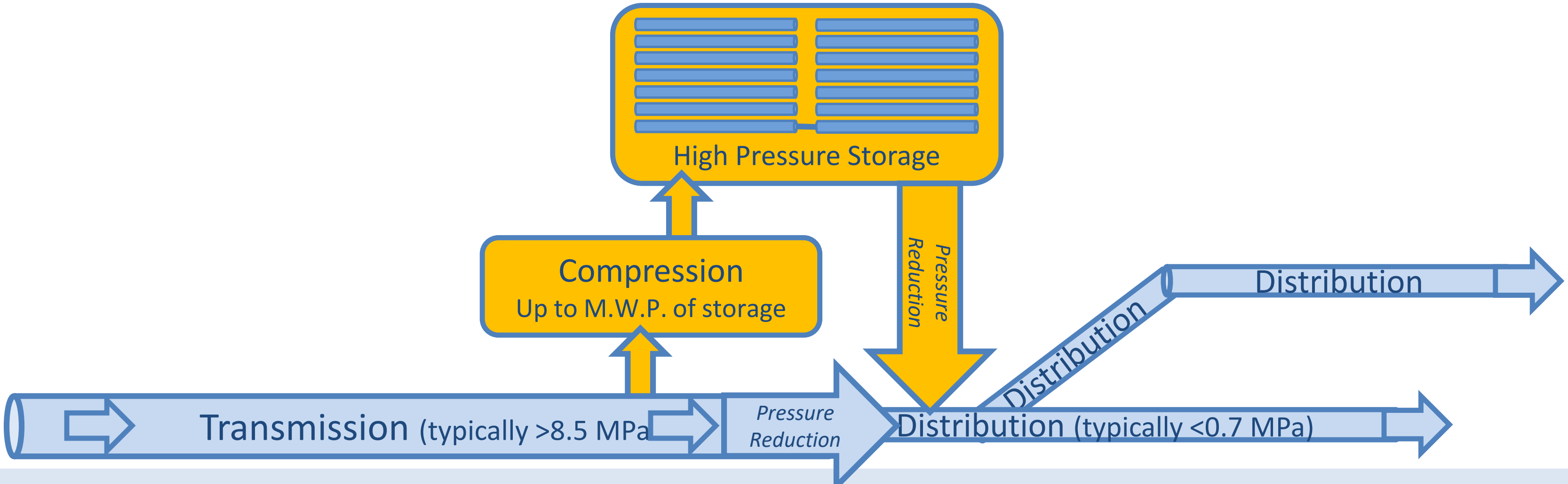
- The system operators determine the actual amount of Linepack (*the amount of gas stored in the pipe system*) by network modelling and instantaneous monitoring of pressures, inflows and outflows.
- As a result, linepack is complex and challenging to include in simple analytical work.
- As an approximation, the line pack storage will be constrained by the difference in gas contained in the pipes when the demand is near zero (gas not flowing), and the gas contained in the pipe when demand is high (pressure drop across the network components is at its maximum allowable).
- For an actual linepack size calculation the spatial peak demand would need to be combined with the details of the regional distribution network. This is a complex network calculation requiring details of the exact network layout and therefore the above approximation will be used.
- Linepack storage is available from all parts of the supply network and comprises of the following items:
  - 1. Usable linepack in the Transmission pipelines
  - 2. Usable linepack in the LTS
  - 3. Usable linepack in the intermediate pressure system by geography
  - 4. Useable linepack in the medium pressure system by geography
  - 5. Usable linepack in the low pressure system by geography
- Currently linepack is not actively used in dynamic calculations by Gas Distribution Network Operators for anything below the intermediate pressure system.
- However, to ensure suitability of the existing distribution system for conversion an estimation of the contribution to line pack of all components is included.
- The linepack contribution to peak demand is assumed to be 10% of the nameplate pipeline capacity, available for 4 hours during peak demand hours

Source: Jacobs Consultancy notes

Hydrogen Storage – Distributed

Above ground storage

- To mitigate against short-term, high demand causing shortages of supply either localised production or storage may be required close to the demand centres.
- This storage is normally provided through line packing.
- If line packing is not sufficient localised storage (*or production*) will need to be provided. Historically with Town Gas and initially with the Natural Gas network, gas holders were used. However, almost all of these have been decommissioned and either the land developed or they remain as listed sites. It is not believed that they would be suitable for hydrogen use.
- Localised compressed storage would be more energy efficient if located on the transmission system as the energy to compress would be reduced due to the higher input pressure.
- Similarly a greater utilisation of the storage can be achieved by allowing the storage to decant into the lower pressure distribution system rather than back into the higher pressure Transmission system.



Hydrogen Storage – Distributed

Above ground storage

- There are different compression / storage pressure options.
  - ‘Transmission outlet pressure’ (“MP”) large vertical tanks storing hydrogen at pressures similar to the Transmission system (*no compression required*) typically 5 – 8 Mpa.
  - ‘High pressure’ steel or composite cylinders / torpedo tube banks at up to 43 – 50 MPa

‘Transmission outlet pressure’ (“MP”) vessels:

- Vessels of 95m^3 would contain ~405kg of H2 each at an installed price of £182k per vessel[(1)] giving an effective capital cost of £11.45 per kWh HHV stored. Assuming 1.3 installation factor[(2)] for 10’s of vessels.
- This storage effectively acts in the same way as additional oversized transmission pipeline capacity would.
- They would be installed in ‘farms’ of 10’s of vessels. E.g. a 20 vessel farm would store 377,600 kWh HHV.
- Sites would need to be installed at Transmission / Distribution nodes.
- Storage could fill and empty for morning and evening peaks (as long as transmission supply capability exceeds localised demand)

(1) – Private correspondence with supplier
(2) – US DoE H2A study installation factor used for gas storage - https://www.hydrogen.energy.gov/h2a_analysis.html

Hydrogen Storage – Distributed

Above ground storage

‘High Pressure’ storage:

- Hydrogen would be compressed from Transmission (preferred in terms of energy efficiency) or Distribution network and stored at pressures of ~43 MPa in steel ‘torpedo’ tubes (as pictured).
- Compression would be required for filling the tubes. The compression stage dictates the cycle rate of the storage as compressors must be sized to fill the storage during reduced demand periods.
- Costings have been calculated from H2A analysis[(1)] for two scenarios:
    - an 18 hour filling time one decant per day (evening peak),
    - a 6 hour fill and two decants per day (morning and evening peaks).
- For one daily cycle the total capital (installed) cost is £55 /kWh stored for storage capacities of >47,000 kWh.

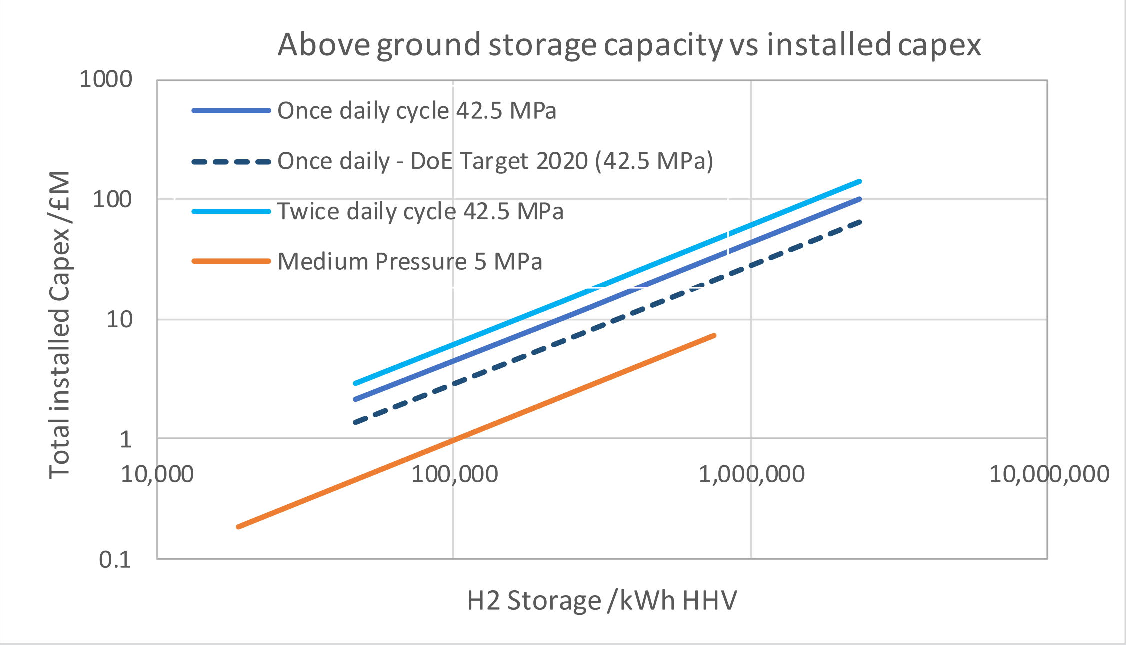
- For twice daily cycles the total capital (installed) cost is £74 /kWh stored for storage capacities of >47,000 kWh.
- Comparing the H2A costing with private correspondence with suppliers gives very good agreement on cylinder costs.
- The US DoE technology targets sets a price reduction of ~45% from today’s prices to the ‘ultimate’ future price. This is likely to come from market sales volume as there is currently a very limited number of global suppliers. However, the price will also be dictated by future steel prices. This cost reduction would reduce the single daily cycle cost to £35 /kWh stored and the twice daily cycle to £54 /kWh stored.
- The footprint is estimated to be 0.20 m^2/kWh HHV

1 US Department of Energy - http://www.hydrogen.energy.gov/h2a_analysis.html

Hydrogen Storage – Distributed

Above ground storage

- Compressed high pressure storage is currently more than 4 times more expensive than MP storage. This is primarily due to the additional cost of the high pressure cylinders, and the requirement for compression.
- Based on this analysis, it is unlikely that the compressed/high pressure would be chosen over the medium pressure option unless the area of demand was a long way from a transmission pipeline.
- If US DoE cost targets are realised, this could lead to a 45% cost reduction on the price of cylinders. This would require a development in the global cylinder supply chain (resulting in a step change in the global market learning rate).



Summary: Key assumptions on Hydrogen Storage (Distributed)

Above ground storage summary

- Table shows the summary data for Above Ground Storage:

		Capex £/kWh stored		Fixed Opex £/kWh stored		Variable Opex kWh e / kWh H2	Daily Cycles
Medium Pressure	**ALL**	**£**	**11.45**	**£**	**0.34**	**0.0**	**2**
High Pressure (333MW stored)	**LOWER**	£	34.64	£	0.82	0.0529	1
	BASE	**£**	**54.75**	**£**	**1.06**	**0.0529**	**1**
	UPPER	£	54.75	£	1.06	0.0529	1
High Pressure (333MW stored)	**LOWER**	£	53.74	£	1.62	0.0529	2
	BASE	**£**	**73.85**	**£**	**1.69**	**0.0529**	**2**
	UPPER	£	73.85	£	1.69	0.0529	2

- Note that the upper bound scenario shown is equal to the base case as this is defined from today’s actual prices and it is believed that this would not increase.

Contents

Carbon Capture and Storage (CCS)

CCS Costs

- It is assumed that the cost of CO_2 capture is included in the costs of the generation technologies themselves. This implies that pure CO_2 arrives at the plant boundary ready for onwards transport to storage sites.
- CCS costs post capture are segmented into onshore transportation, offshore transportation and offshore storage.
- The CCS costs of transportation and offshore storage are calculated post capture in the hydrogen generation technologies.
- The CCS costing captures the following processes:
  - The captured CO_2 is first transported via onshore pipelines to shoreline terminals.
  - The CO_2 is then compressed to 25MPa and sent via offshore pipelines to the storage regions.
  - Detailed cost analysis of the required offshore infrastructure is performed for the required flow rates, based on engineering inputs on the amounts of CO_2 injection wells needed.
  - Offshore infrastructure requirements including CO_2 injections wells, platform, seismic appraisal etc. are costed to generate the levelised lifetime storage cost (£/t).

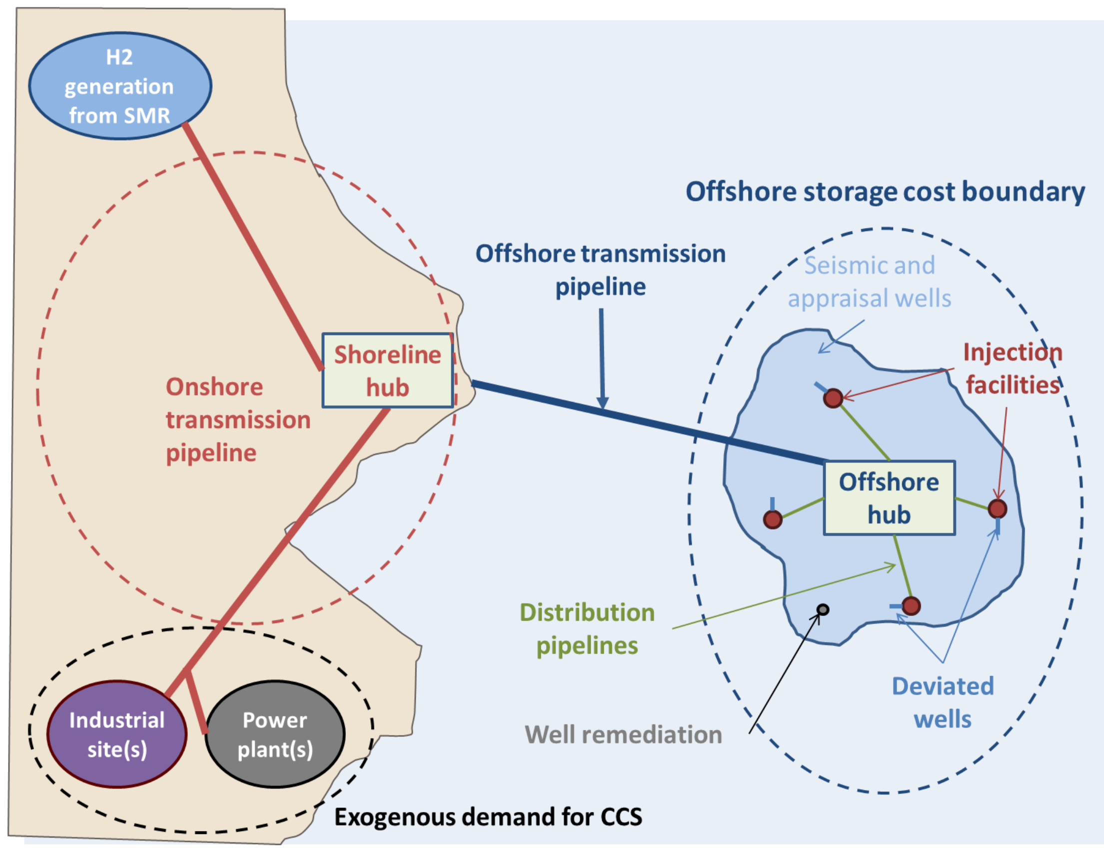
Source: Element Energy

Carbon Capture and Storage (CCS)

CCS System design

- This evidence includes assumptions for CO2 transmission pipelines built between nodes, allowing modelling of localised production as well as centralised production.
- In addition to the endogenous CO2 produced from hydrogen production, additional CO2 demand can be supplied as a base load. This will allow the correct sizing of carbon transmission and storage for the hydrogen production as well as external carbon capture systems such as industry or electricity generation.
- It should be noted for all of the CCS data that the technology is immature and therefore the costs may change for many reasons e.g. slow market size development, safety legislation, etc.

Boundary of the CBA model for offshore storage costs



Carbon Capture and Storage (CCS)

Onshore transportation

- The CO_2 captured from the CCS plants is assumed to be at 10MPa[(1)] and more than 90% pure
- This is then transported using onshore pipelines to the shoreline terminals
- The minimum required pressure to maintain dense phase is 8MPa[(1)]
- Therefore the onshore pipelines are sized to have a maximum pressure drop of 2MPa
- The CO_2 is then compressed up to 25MPa before being sent via offshore pipelines
- Cost estimates are shown below:

ID	Shoreline terminal	Latitude	Longitude
1	Bacton	52.86	1.46
2	Forth	56.01	-3.69
3	Humber	53.36	0.23
4	St Fergus	57.58	-1.84
5	Barrow	54.09	-3.18
6	Wirral	53.34	-3.32

Onshore pipeline length (km)	Capex (£/inch/km)[1]	Opex (share of capex)[1]
180	49,900	0.5%
500	48,400	0.5%
750	47,800	0.5%

Compressor capex (£/MW)[2,3]	Opex (share of capex)[2,3]
3,750,000	4%

1 http://www.zeroemissionsplatform.eu/library/publication/167-zep-cost-report-transport.html Zero emissions platform - The Costs of CO2 Transport
2 Energy Technologies Institute – UK Storage Appraisal Project
3 Energy Technologies Institute – Brine production cost-benefit analysis tool

Offshore transportation

- The CO_2 is sent from shoreline terminals via offshore pipelines to the offshore storage regions
- Based on data on the storage site bottom hole pressure and depth to storage centroid, the minimum well head pressures are calculated for each region
- The pipelines are then sized based on the flows and the distance to the offshore storage region to ensure the minimum well head pressure is achieved.

Transmission pipeline length (km)	Capex (£/inch/km)[1,2]	Opex (share of capex)[1,2]
1	£180,288	1%
25	£154,247	1%
30	£138,555	1%
40	£116,436	1%
50	£103,165	1%
60	£93,483	1%
80	£82,632	1%
100	£76,122	1%
150	£67,107	1%
200	£62,600	1%
250	£60,096	1%
300	£58,093	1%
400	£55,965	1%
500	£54,587	1%
600	£53,669	1%
700	£53,085	1%

	Flow rate (Mt CO2/y)						
Pipeline diameter (inches)	2	5	10	15	20	40	60
4.5	5.80E+00	3.61E+01	1.44E+02	3.25E+02	5.77E+02	2.31E+03	5.19E+03
6	1.30E+00	8.07E+00	3.22E+01	7.25E+01	1.29E+02	5.15E+02	1.16E+03
8	2.91E-01	1.81E+00	7.21E+00	1.62E+01	2.88E+01	1.15E+02	2.59E+02
10	9.17E-02	5.67E-01	2.26E+00	5.08E+00	9.03E+00	3.61E+01	8.11E+01
12	3.58E-02	2.21E-01	8.78E-01	1.97E+00	3.50E+00	1.40E+01	3.14E+01
14	1.62E-02	9.94E-02	3.95E-01	8.86E-01	1.57E+00	6.28E+00	1.41E+01
16	8.16E-03	4.99E-02	1.98E-01	4.44E-01	7.87E-01	3.14E+00	7.06E+00
18	4.47E-03	2.72E-02	1.08E-01	2.41E-01	4.28E-01	1.71E+00	3.83E+00
20	2.61E-03	1.58E-02	6.24E-02	1.40E-01	2.48E-01	9.88E-01	2.22E+00
22	1.61E-03	9.69E-03	3.82E-02	8.54E-02	1.51E-01	6.03E-01	1.35E+00
24	1.03E-03	6.20E-03	2.44E-02	5.45E-02	9.66E-02	3.84E-01	8.63E-01
26	6.89E-04	4.12E-03	1.62E-02	3.61E-02	6.39E-02	2.54E-01	5.70E-01
28	4.74E-04	2.82E-03	1.10E-02	2.46E-02	4.36E-02	1.73E-01	3.89E-01
32	2.42E-04	1.43E-03	5.56E-03	1.24E-02	2.19E-02	8.69E-02	1.95E-01
36	1.34E-04	7.85E-04	3.05E-03	6.77E-03	1.20E-02	4.73E-02	1.06E-01
40	7.93E-05	4.60E-04	1.78E-03	3.95E-03	6.96E-03	2.75E-02	6.16E-02
44	4.94E-05	2.85E-04	1.09E-03	2.42E-03	4.27E-03	1.68E-02	3.77E-02
48	3.21E-05	1.84E-04	7.04E-04	1.56E-03	2.74E-03	1.08E-02	2.41E-02
52	2.16E-05	1.23E-04	4.69E-04	1.03E-03	1.82E-03	7.14E-03	1.60E-02
56	1.50E-05	8.49E-05	3.23E-04	7.10E-04	1.25E-03	4.88E-03	1.09E-02

The tables above show examples of the pipe capex (by pipe diameter) and pressure drop by flow rates and diameter.

1 Energy Technologies Institute – UK Storage Appraisal Project
2 Energy Technologies Institute – Brine production cost-benefit analysis tool

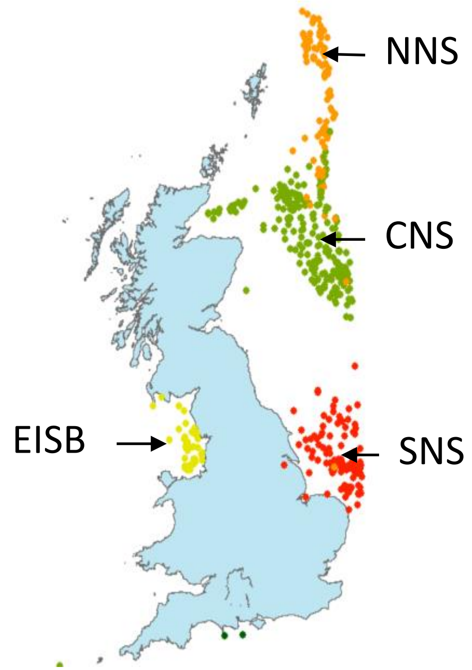
Carbon Capture and Storage (CCS)

Offshore storage sites

- CO_2Stored is a detailed database containing parameters on the geology of around 580 offshore storage sites and the required infrastructure for CO2 storage
- This includes storage site data on:
  - Storage ID
  - Geographic area
  - Storage type
  - Latitude and Longitude
  - Area (m2)
  - Water depth(m)
  - Depth to storage(m)
  - Existing wells
- The database also contains data on the number of required CO_2 injection wells at varying flow rates (Mt CO_2/y) and injection durations (10 – 40 years) and the resulting bottom hole pressure (MPa)

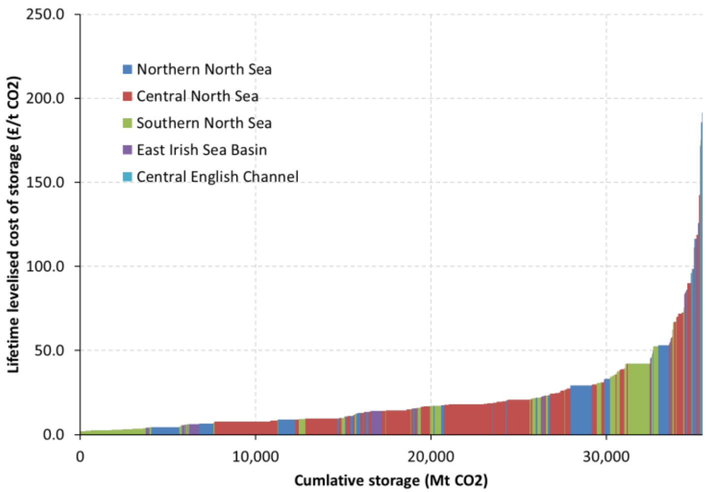
Offshore storage regions

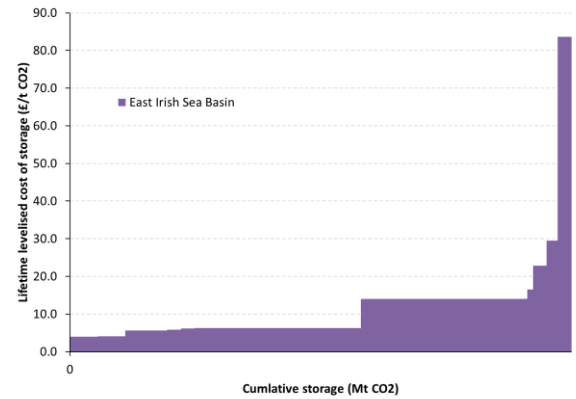
- The storage sites are grouped into four offshore regions, based on the spatial clustering:
  - Northern North Sea (NNS)
  - Central North Sea (CNS)
  - Southern North Sea (SNS)
  - East Irish Sea Basin (EISB)
- Individual MACC outputs are calculated for each offshore storage region to generate the cost of utilising the offshore storage, which include:
  - Levelised lifetime cost of storage (£/t CO_2)
  - Maximum available storage (Mt CO_2)
  - Maximum flow rate (Mt CO_2/y)

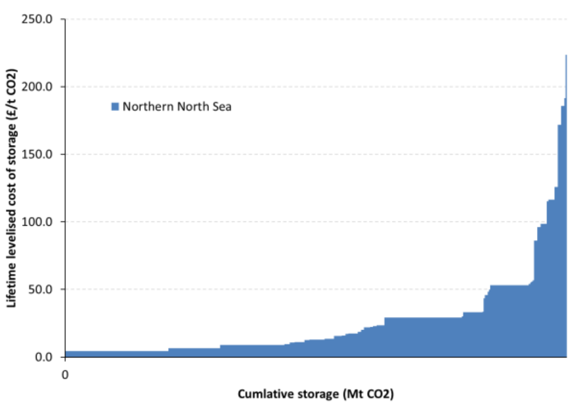


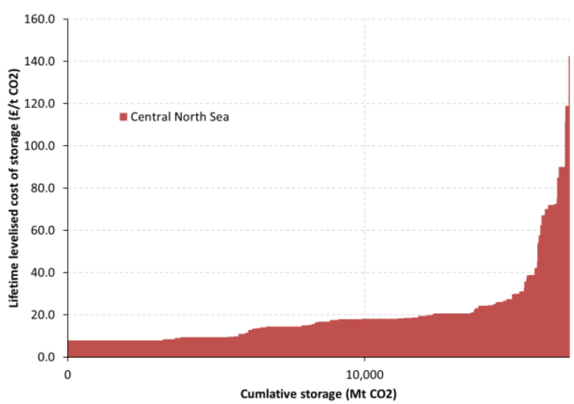
Carbon Capture and Storage (CCS) - CO_2 storage

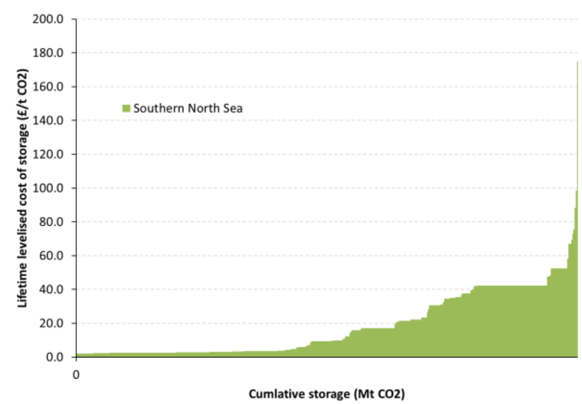
Summary data – MACC outputs for individual storage regions[1]











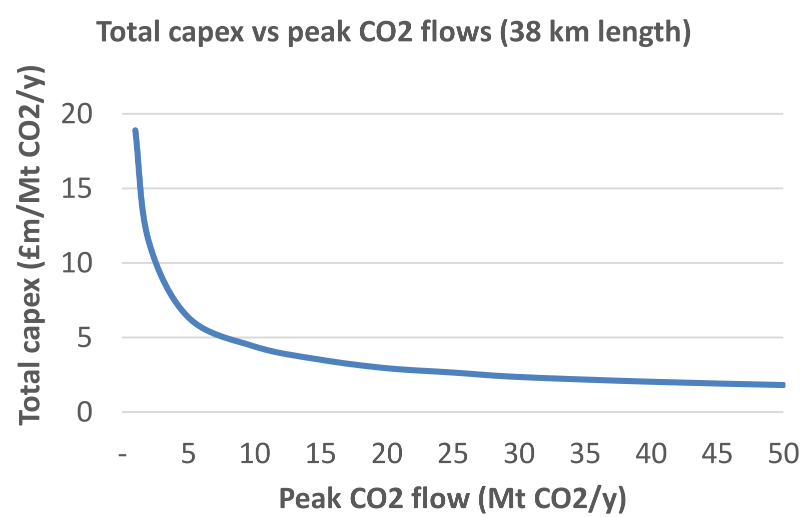
1 Energy Technologies Institute – Brine production CBA tool

Carbon Capture and Storage (CCS) - CO2 Onshore Transmission

Summary data – sample outputs between two onshore regions

- The CO_2 onshore pipelines are sized to carry varying peak flows between spatial regions based on their distance and allowable pressure drop
- The required compressor size to maintain the pressure at the end of the pipeline and the associated compression energy is also calculated
- Outputs for such an onshore connection between two spatial regions are shown below

ID	Region 1	Region 2	Distance (km)	CO2 flow (Mt CO2/y)	Pipeline diameter (inches)	Compression energy (MWhe/Mt CO2/y)	Total capex (£m)	Total opex (£m/y)
1	London	Windsor	38	1	10	396	18.90	0.10
2	London	Windsor	38	2	12	609	23.00	0.14
3	London	Windsor	38	5	16	848	31.78	0.23
4	London	Windsor	38	10	22	649	43.99	0.33
5	London	Windsor	38	15	26	614	52.64	0.42
6	London	Windsor	38	20	28	742	58.79	0.55
7	London	Windsor	38	25	32	580	66.15	0.58
8	London	Windsor	38	30	32	834	70.65	0.78
9	London	Windsor	38	40	36	805	81.21	0.96
10	London	Windsor	38	50	40	729	90.52	1.08

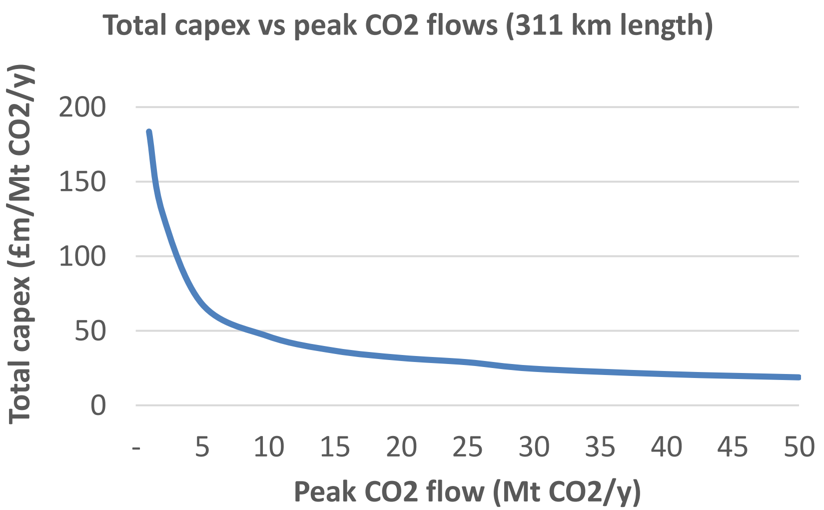


Carbon Capture and Storage (CCS) - CO2 Offshore Transmission

Summary data – sample outputs between onshore and offshore regions

- The CO2 offshore pipelines are sized to carry varying peak flows between shoreline terminals and offshore storage regions based on their distance and allowable pressure drop based on the well head pressure for storage sites
- The shoreline compressor is sized to increase the pressure to maximum allowable limit to minimise pipeline size and avoid offshore boosting, the associated compression energy is also calculated
- Outputs for such an offshore connection are shown below:

ID	Region 1	Region 2	Distance (km)	CO2 flow (Mt CO2/y)	Pipeline diameter (inches)	Compression energy (MWhe/Mt CO2/y)	Total capex (£m)	Total opex (£m/y)
1	St Fergus	NNS	311	1	10	6,795	183.69	1.95
2	St Fergus	NNS	311	2	14	6,795	258.90	2.82
3	St Fergus	NNS	311	5	18	6,795	339.94	3.98
4	St Fergus	NNS	311	10	24	6,795	462.95	5.79
5	St Fergus	NNS	311	15	28	6,795	549.80	7.24
6	St Fergus	NNS	311	20	32	6,795	636.66	8.69
7	St Fergus	NNS	311	25	36	6,795	723.51	10.14
8	St Fergus	NNS	311	30	36	6,795	738.06	10.87
9	St Fergus	NNS	311	40	40	6,795	839.45	13.05
10	St Fergus	NNS	311	50	44	6,795	940.85	15.23



Appendices

- **Build Rates**

Build rates

Qualitative approach to identifying constraints of future build rates

- A qualitative assessment of the factors that could constrain build rates for key components of the hydrogen for heat supply chain is provided on the following slides.
- Build rates for many of the components will be dictated by global supply demands and are very difficult to predict.
- National constraints will exist for the provision of skilled labour for changing boilers/meters/etc. For this the UK population will be the main pool for this employment. The dataset gives the number of person-days required for each category in each region to allow workforce requirements to be calculated exogenously. Combined with the rate of deployment (number of available days to complete the work) the required workforce size can be calculated and challenged against available personnel.
- As time passes and markets develop constraints will change so may need updating over time.

Build Rates

Technology	Component	Skilled Labour (Production)	Specialist Labour (Design)	Skilled Labour (Installation)	Global Production Capacity	Raw materials	Produced Components	Commentary
SMR	Furnace	Plants would likely be built in US or Continental Europe.	A number of companies are currently designing reformers	Large plant installations would primarily be undertaken by specialist teams operating globally	Est. 800 kTonnes/year production capability.			Of the world's 50 Mtonnes of H2 produced a year it is estimated 48% is by reforming. Assuming a 30 year plant life this gives ~ 800 kT/year installation capabability globally equating to 27 TWh of H2 (~1/5 of UK gas demand)
	Reactor					Nickel used in catalysts		
	PSA					Typically activated charcoal or zeolites.	Standard component of many plants	
	Carbon Capture						MEA or PSAs used	
Gasification	Feedstock handling	Large plants would be built overseas, whereas small biogasifiers could be built in the UK	A number of companies are currently designing gasifiers including UK companies for small scale bio/wdf units	Large plant installations would primarily be undertaken by specialist teams operating globally	10's of plants being installed - big increase in plant deployments across Asia recently.			There are 238 operational coal gasifiers in the world with 74 being built and more planned [2016]. Biogasification is expected to be on the 50 - 250 MW scale. At this scale more feasible to be built in the UK as opposed to the coal gasifiers built overseas.
	Furnace							
	Reactor					Nickel used in catalysts		
	PSA					Typically activated charcoal or zeolites.		
	Carbon Capture							
Electrolysis	Switch Gear		Relatively standard electrical design	Large plant installations would primarily be undertaken by specialist teams operating globally or continentally.	Components used in many applications		Supply chain would need to develop to keep up with production increase	There will need to production capacity uplift by a number of orders of magnitude to fulfill the potential hydrogen for heat demand for electrolysis. It is likely this growth will happen anyway with the potential large increase in hydrogen transport demands globally. With one of the handfull of existing suppliers in the UK there is potential for UK manufacturing investment.
	Stacks	Reliant on production companies expansion and ability to train new staff	A small number of companies producing stacks in the world.		Currently only 10s of MW per year globally. Would need significant upscaling to meet required demands	Platinum and Iridium typically used as catalyst on plates.	Stack production is labour intensive and may require degree of automation	
	Purification		Standard gas processing technology		10s to 100s of companies globally	Typically activated charcoal or zeolites.	As with CCS PSRs likely to be used.	
Compression	Compressors		Technology development required from small number of potential companies		10s of companies globally	Steel		Many small compressor manufacturers have been taken over by larger companies in so reducing the number of companies in the market. Investment in development of new technology may be required to provide cost optimised solution.

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Transmission	Pipelines	Pipes are standard across many applications (oil & gas)	Little specialist design required	Majority of installation is civil engineering	Good - Likely to come from overseas	Polyethylene or steel		The most probable constraint on pipelines would be the planning authorisation and required civil works rather than pipe/component supply.
	DGs	Small number of manufacturers though simple devices	Design for hydrogen more specialised than natural gas though not a complex item	Existing natural gas workforce could be trained in handling hydrogen (1 - 2 days training each)				
Storage	Medium Pressure	Welders and sheet metal workers (on foundary scale)	Current designs quite basic	Pipe fitters and welders available regionally.	Small number of companies globally with long lead times. Large uptake could dictate requirement for UK based manufacture	Steel		
	HP Compressors							*As per Transmission Compression*
	HP Storage				Very limited potential suppliers	Steel		Limited number of companies producing high pressure cylinders
	Salt Cavern	Production time for a salt cavern is long - takes many years of planning on top.			Equipment for creating salt caverns very specialised.	Water		Due to geographic limitations of potential sites the knowledge on the production of salt caverns is highly specialised.
Distribution	New Pipe		A dedicated team to design upgrade / conversion works would be required. Likely a number of teams for each GDN	Existing natural gas workforce would require additional training (1 - 2 days). Additional people would be required, as existing work would be in parallel.		Polyethylene		The available workforce to complete the programme could control the roll out speed, along with the level of distruption that can be permitted in each region at any time.
	Pipe upgrade					Polyethylene		
	Isolations							
	Meters	Production would be factory line	Development work required in designing suitable meter.	A dedicated team would be employed to fit the meters. Number of people required depends on roll out rate	Technology not yet developed			Depending on the complexity of the meter required will dictate the build requirements. Due to the numbers a dedicated production facility could be created.
End Use	Boilers	A number of suppliers would be required, potentially using existing production staff	Development work still required to design the h2 boilers (and other appliances)	Although existing gas safe fitters would be suitable there won't be sufficient available - require additional fitters training	Currently none. Though likely existing natural gas boiler producers will start H2 boiler produciton	Catalysts?		There needs to be development work before we can properly understand raw material requirements.

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