Oil & Gas Authority

UKCS Energy Integration

Final report

Annex 3. Hydrogen

Department for Business, Energy & Industrial Strategy

THE CROWN ESTATE

ofgem

December 2021

UKCS Energy Integration project

Oil & Gas Authority

Funded by £900k grant from the Better Regulation Executive's Regulators' Pioneer Fund

Led by Oil & Gas Authority

in collaboration with

Department for Business, Energy & Industrial Strategy

THE CROWN ESTATE

ofgem

- Engaged widely across industry and regulators
- Understood potential of UKCS assets and technologies for net zero, and synergies across the different energy sectors
- Identified hurdles (economic, regulatory) and recommend avenues to realise full technologies' value

Project timeline

1. **Technical options** *1Q 2Q 2019* Lloyd's Register

2. **Economic and regulatory assessment** *3Q2019-1Q2020* EY

3. A **Phase 3** is proposed to follow to implement recommendations, accelerating UKCS energy integration projects

This document is an annex to the final report of the UKCS Energy Integration Project available on the OGA web site.

This annex should be read in conjunction with the assumptions and notes contained in the main report.

Information and findings in this Annex should be considered in the context of ongoing Government work on policy approaches for offshore renewables, as referenced in the Appendix.

Contents

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Hydrogen – Summary Findings

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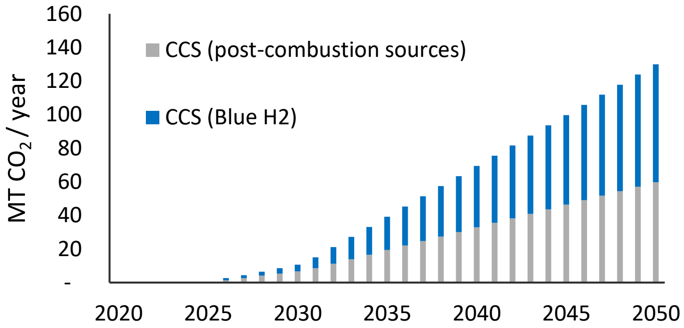
Blue hydrogen could support the faster CCS ramp-up

- Blue Hydrogen can accelerate the growth of CCS through the 2020s/30s, by leveraging available supply of natural gas and mature technologies
- Provides a zero-carbon fuel (Hydrogen) at cost advantage with conventional power gen when combined with CCS (BCR up to 1.4)
- Leverage oil and gas infrastructure (e.g, terminals) and capabilities
- Would rely on the hydrogen market/sales to absorb CCS cost

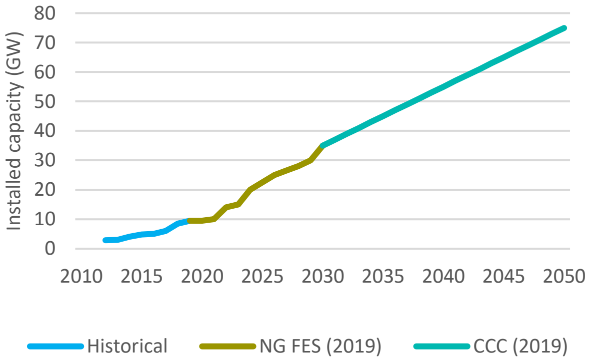
Green hydrogen could be an important enabler of large-scale windpower expansion

- Hydrogen from renewable power could provide energy storage for the growing offshore windpower sector, to address supply intermittency and transportation of energy over long-distance
- Due to the high electrolyser costs, green H_2 is not economically attractive today (BCR ~ 0.7) but technology improvements could reduce these costs approaching projects breakeven in this decade

Blue hydrogen contribution to CCS ramp-up (EIP central case[1])



Potential growth in UK offshore windpower capacity[1]



1. See notes on methodology sources in appendix

Hydrogen - Recommendations

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1. Continue activities towards development of hydrogen markets

- Local H_2 demand clusters initially identified, include industrial hubs (e.g. Merseyside, and Humberside)
- Ongoing work by BEIS on considering more widespread H_2 distribution and uses (e.g. fuel switching) will be critical to unlock hydrogen growth
- Ongoing work by Ofgem, National Grid and Gas Networks to pilot hydrogen transportation (inc. blending with natural gas and reuse of existing pipelines)

2. Promote blue hydrogen to accelerate net zero energy clusters

- Blue hydrogen could accelerate CCS ramp-up by providing more scalable CO_2 sources and improving overall project economics
- A faster blue H2 / CCS growth could improve opportunities to reuse O&G assets (e.g. terminals, pipelines and natural gas resources)

3. Accelerate development of hydrogen technologies

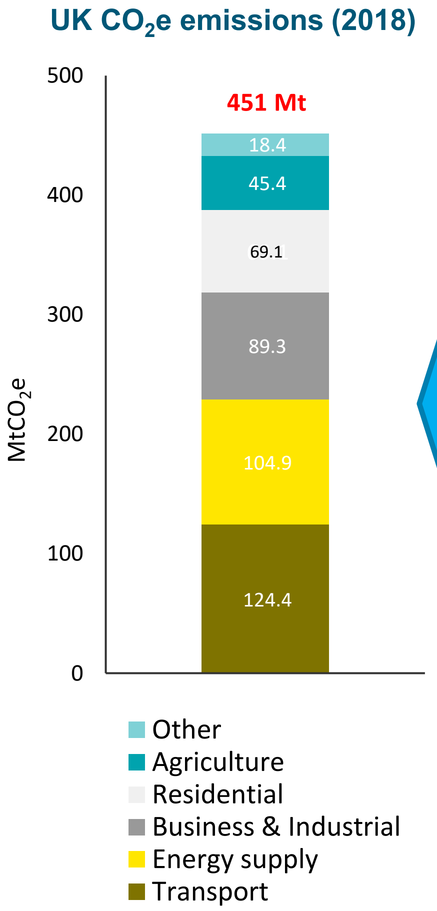
- R&D to abate electrolysers' costs and increase their energy efficiency
- Technologies for the transportation and distribution of hydrogen, including converting existing pipeline systems
- Technologies for cost-efficient fuel switching

4. Enhance regulatory coordination across CCS and Hydrogen

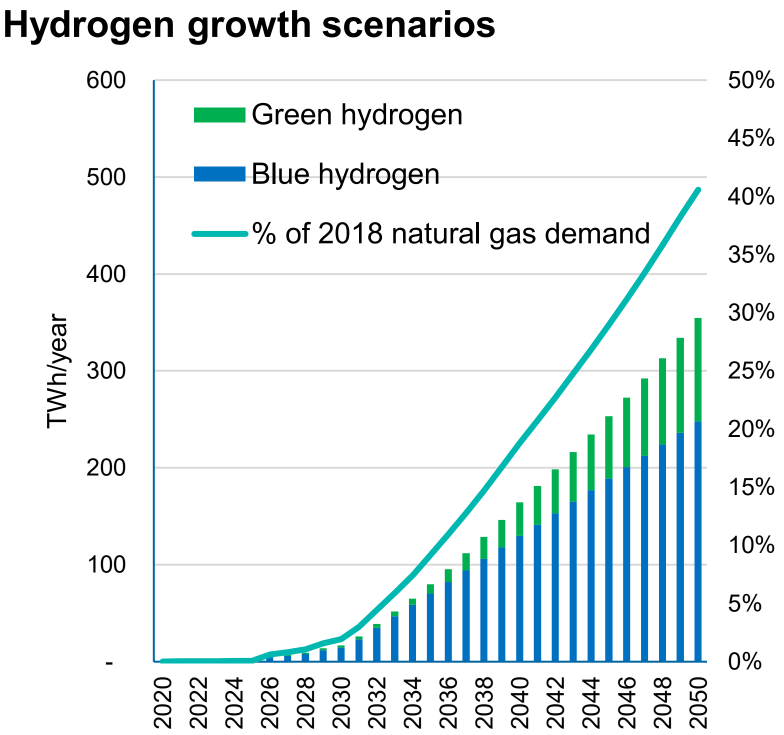
- Regulators coordination to expedite industry projects
- Align planning and consenting regimes to support cross-industry opportunities (e.g. O&G, CCS and blue H2)

UKCS hydrogen opportunity

Hydrogen demand and supply sources



- Hydrogen can be a way to deliver low-carbon energy to a large share of these users
- Delivered as gas
- Pure H2 or gas blending
- Accelerated transition (lower hurdles / costs to convert certain uses than electrification)



Unlocks power transmission and storage

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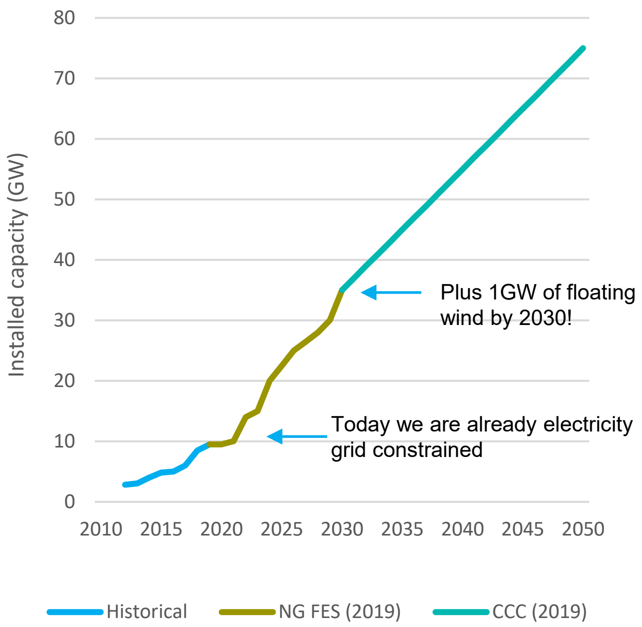
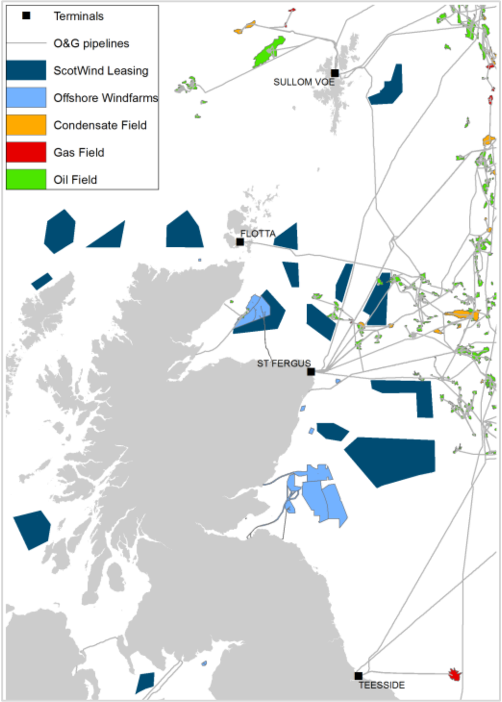
Targeted growth in UK offshore windpower capacity



Expansion in more distant regions
Eg recent Scotwind Leasing areas (2020)



- Converting renewable electricity to hydrogen…
- Can provide efficient transportation / buffering and storage
- Can give access to extensive natural gas distribution (eg via blending)
- Can open export market for zero carbon energy (H2 exports by pipelines to Europe and ships)

Blue hydrogen – ramp-up

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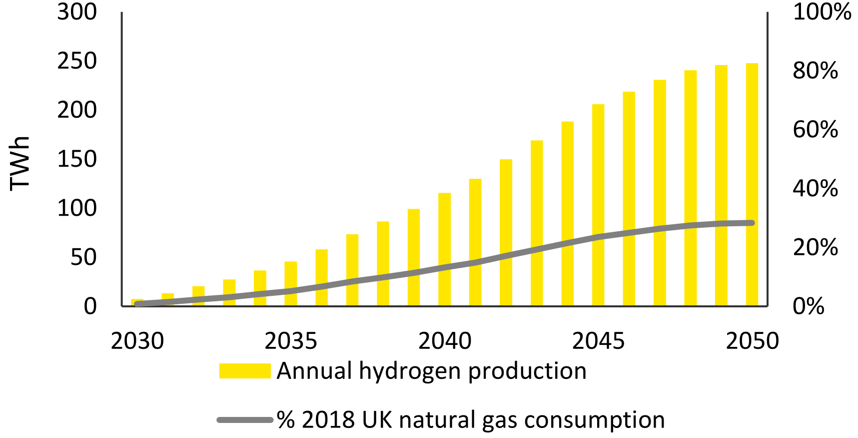
Blue hydrogen requires investment in SMR (or other technology, such as ATR) used to produce hydrogen from hydrocarbon fuels. SMR is a well established technology, with capex estimated at circa £0.8m/MW capacity.

To ramp up the required blue hydrogen supply (NG FES scenario), we estimate that over 200 blue hydrogen notional plants, with a total capital investment requirement of £16.6 bn (excluding CCS costs).

In addition, more than 700 Mt CO_2 would need to be stored by 2050.

Blue hydrogen expected production vs. UK natural gas consumption



Potential roll out of blue hydrogen technology

	2030	2035	2040	2045	2050
Number of SMR reactors operational [1]	6	38	97	173	208
Hydrogen produced (TWh/year)[2]	7.5	45.7	115.6	205.9	247.9
Cumulative capital investment (£bn)[3]	0.5	3.1	7.8	13.8	16.6
Total carbon stored (cumulative, Mt)	2.1	42.7	165.2	403.6	738.5

1 SMR reactor capacity 100 MW.
2 Process efficiency 70%.
3 SMR capex only. Excludes additional capex in carbon capture technology that would be required to turn “grey” hydrogen into “blue” hydrogen.

Sources: EY analysis; National Grid FES data

Blue hydrogen – locations

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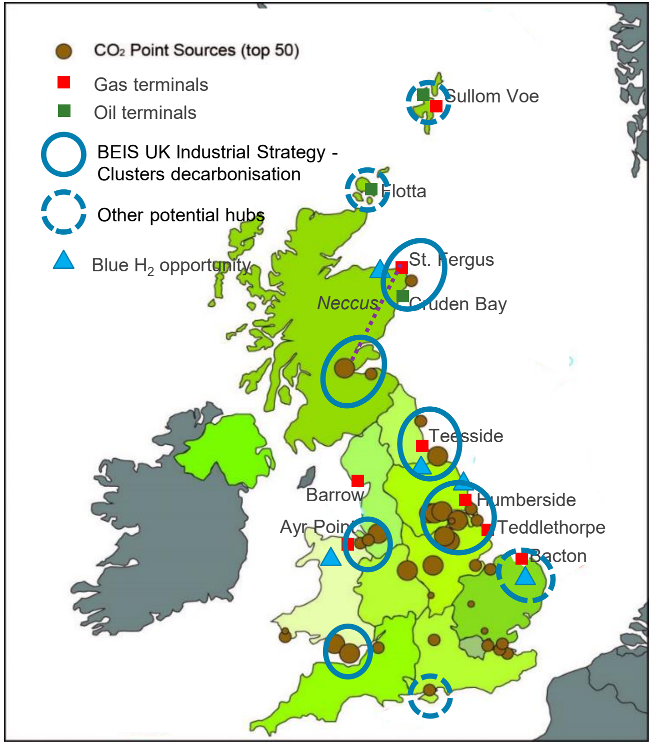
UK industrial clusters and largest CO_2 sources



CO_2 point sources (ETI)

CCS / blue hydrogen potential ramp up

Clusters and Hubs	CCS	Blue H_2	CCS / blue hydrogen development potential
St Fergus - Grangemouth			*Acorn* project. CCS from BlueH2 and combustion sources. NECCUS link from Grangemouth (4.3MtCO_2/yr)
Teesside			*Net zero Teesside* decarbonisation including blue H_2. Teesside industrial cluster emissions (3.1MtCO_2 p.a.)
Humberside			*Zero Carbon Humber* (12.4 MtCO_2/yr) includes Blue H2, BECCS and links with H21 project ources (20MtCO_2/yr)
Bacton			Potential Blue H2 from SNS gas and interconnector imports. Green H2 from large expected windpower exp.
Merseyside			HyNet Blue Hydrogen (volumes TBD) and additional CCS from industrial sources (2.6 MtCO_2/yr)
South Wales			Large industrial cluster with 8.2 MtCO2/yr emissions, CO_2 could be transported by ship to storage sites
Southampton			Industrial cluster with 2.6 MtCO2/yr emissions, CO_2 could be transported by ship to storage sites

CCS volumes scenario	Year	2025	2030	2040	2050
	MtCO_2 p.a.	~4	~10	~70	~130

1) UK Industrial Strategy and Industrial Cluster Mission (BEIS, see appendix for references), CCS and blue hydrogen potential (EIP analysis)

Blue Hydrogen supply

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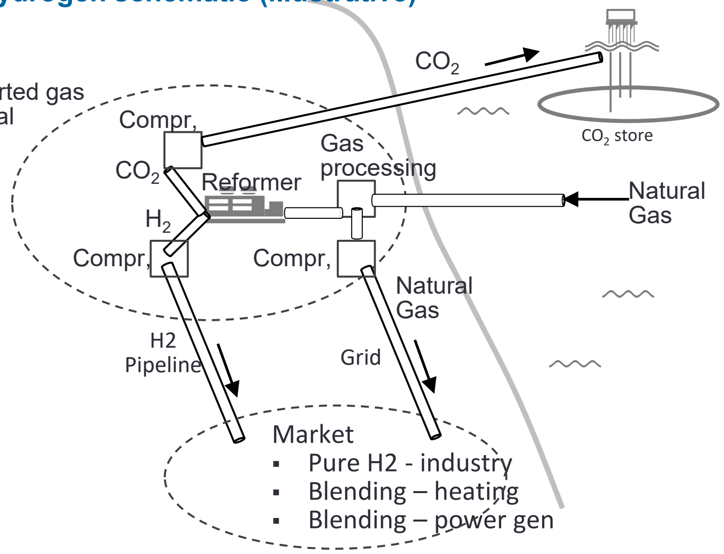
Blue hydrogen schematic (illustrative)



Steam methane reforming plant

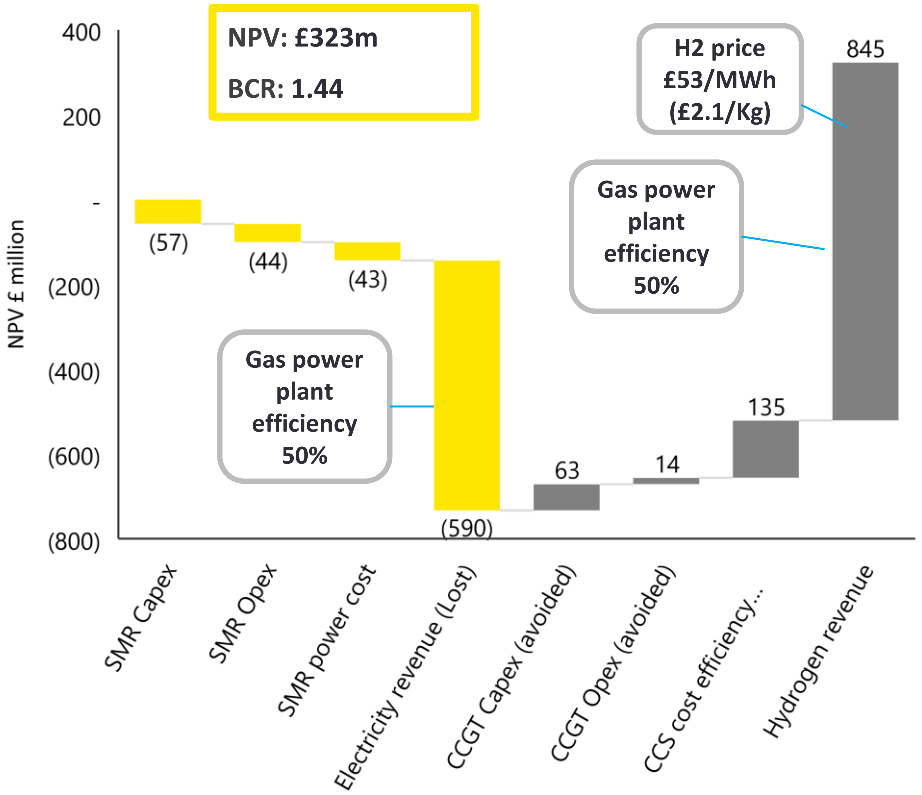
Blue hydrogen economics (illustrative)	
Characteristics	Methane reformer Capacity: 200MW th (output) Efficiency: 75% Natural gas consumption 19.5T/h (8.41Bcf/y) H2 production 6T/h (1.75 TWh/yr) CO2 capture 51T/h (0.45 MTCO2 pa)
Capex	Equipment £130m Fabrication 78 Installation 20 Project costs 45 Total Capex £203m
Opex	Fixed £11m/yr Variable 27 Natural gas 62
H_2 levelised cost	**2.66 £/Kg plus** **0.17 £/Kg offshore CO2 T&S @ £20/tCO2** **2.83 £/Kg (85 £/MWh)**

Breakeven with electricity wholesale price (5p/kWh, 2020): £1.68/KgH_2

Opportunity: leverage low natural gas prices, deploy existing technology (reforming), repurposing O&G infrastructure, support growth of onshore H_2 demand,

Blue hydrogen – Economics

Blue Hydrogen business model



- A blue-hydrogen and CCS combination is more commercially attractive than providing an equivalent amount of energy through conventional power plants and then sequestering the CO_2 via CCS
- This result is principally driven by:
    - Higher efficiency of the hydrogen production processes relative to gas-fired power generation
    - Cost savings on the CCS process (carbon capture stage) when installed in combination with methane reforming, vs post-combustion capture
- In alternative to steam methane reforming (SMR), autothermal reformers (ATR) can have better CCS capture rates (95% vs 90%) and better efficiency, enabling a smaller plant and saving on capex

Green hydrogen – ramp-up

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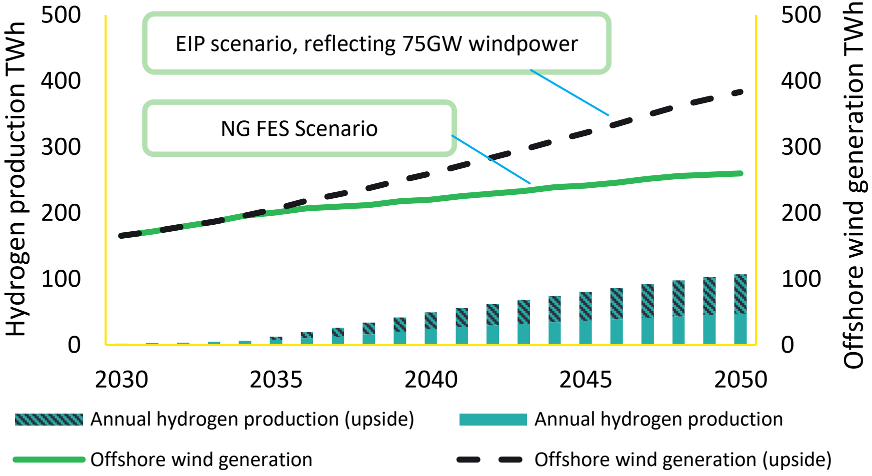
The principal capex associated with green hydrogen is the electrolyser, with required capital investment equating to roughly £2m/MW of capacity.

Using National Grid FES projections for green hydrogen power demand, we anticipated that around 31 electrolysers would need to be deployed by 2050 with a total investment ask of £15.5 bn.

Green hydrogen production is currently more costly than blue hydrogen production. However it is noted that the scale of green hydrogen production could increase if electrolyser capital costs fall and/or there is a significant increase in windpower generation.

Our upside scenario considers higher offshore wind capacity and load factors and hydrogen production more than doubling by 2050.

Green hydrogen base case and upside scenario



Potential roll out of green hydrogen technology

	2030	2035	2040	2045	2050
Number of electrolysers[1]	2	5	16	24	31
Installed electrolyser capacity (GW)	0.4	1.3	4.0	6.0	7.8
Hydrogen produced (TWh/year)[2]	2.3	8.0	24.7	36.9	47.6
Cumulative capital investment (£bn)	0.8	2.6	8.1	12.0	15.5
Emissions abatement (Mt/CO_2/year)[3]	0.5	1.8	5.4	8.1	10.5

1 Electrolyser capacity 250 MW.
2 Process efficiency 70%, with losses arising from electrolysis and hydrogen compression.
3 Assumes green hydrogen is produced from zero carbon renewable power and substitutes for methane in the generation of heat.

Sources: EY analysis; National Grid FES data

Hydrogen supply – Green

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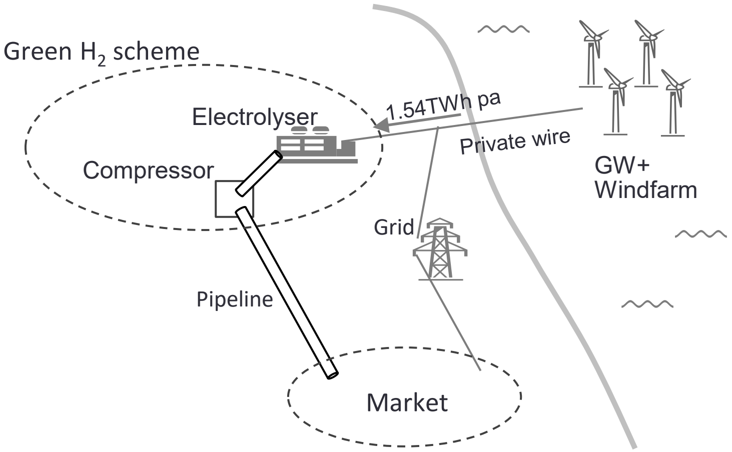
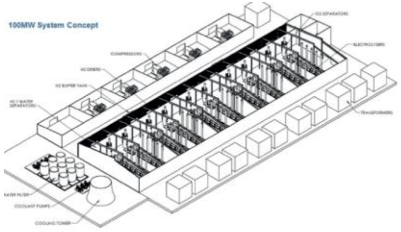
Green hydrogen schematic (illustrative)



New technology proton exchange membrane (PEM)

Gigc-scale electrolysis plant (concept)



Green hydrogen (electrolysis) economics (illustrative)	
Characteristics	Onshore electrolyser Capacity: 250MW (£2m/MW) H_2 conversion efficiency: 70-80% Project life: 31 yrs
Capex	Electrolyser £129m (£0.52m/MW) H2 compressor £38m (£1.15/KgH_2yr) Ancillaries £333m (2x equipment) Total Capex £500m
Operational	Operational hours: 8,760 / yr H_2 output (net): 1.54 TWh/yr H_2 output (net): 39.5 kt/yr Electricity consumption: 2.19 TWh/yr Electricity price: 53 £/MWh (landed from windfarm at cost) H_2 compression: 12% of H_2 gross output Opex: £16.7 / yr
H_2 levelised cost	**0.63 £/Kg (excl. electricity)** **3.60 £/Kg (incl. electricity)**

Breakeven with electricity wholesale price (5p/kWh, 2020): £1.68/KgH_2

Opportunity: Debottleneck windpower growth, leveraging ultra-low renewable electricity prices (oversupply), accelerate technology development (electrolyser cost reduction)

Green hydrogen – economics

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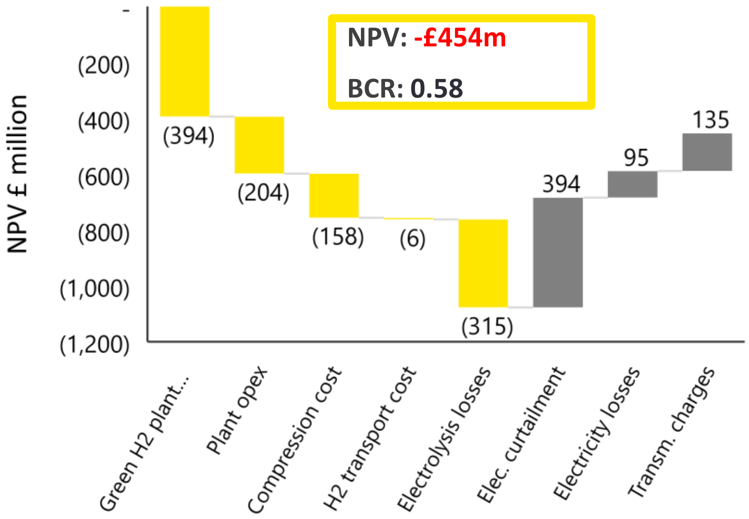
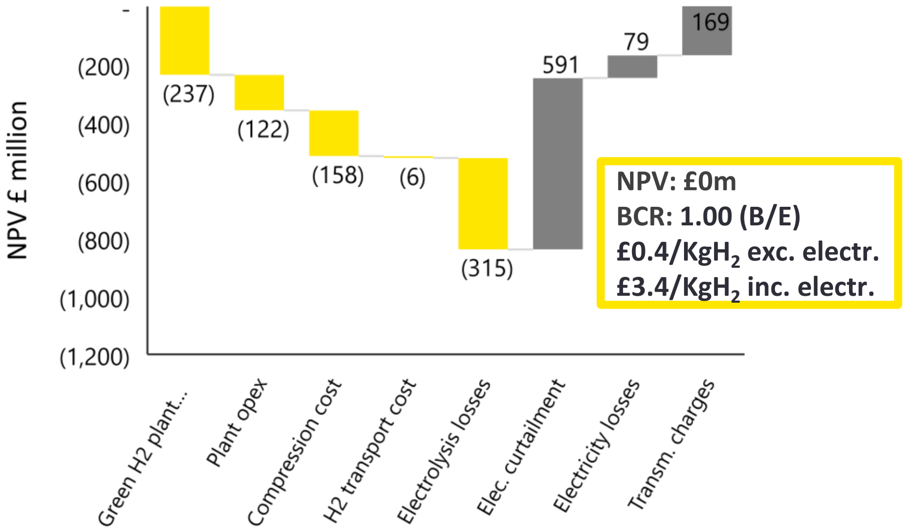
Reference case – today's technology



Sensitivity – breakeven case



- The significant benefits from avoiding a 25% curtailment (£394m levelized) are not sufficient to offset electrolysis Capex and operating costs (incl. electrolysis losses)
- When considering compression and pipeline costs, H_2 transport could be ~30% more efficient than el. transmission

- Higher curtailment levels for renewable power (~37.5%) would not be unrealistic
- Technology developers[1] are targeting ~40% cost reduction in electrolyser equipment, and plant costs overall could be reduced by reusing O&G gas plants
- These assumptions would potentially allow the green hydrogen technology to break even

1) ITM Power, Ørsted, Element Energy - Gigastack Project

Hydrogen – summary economics

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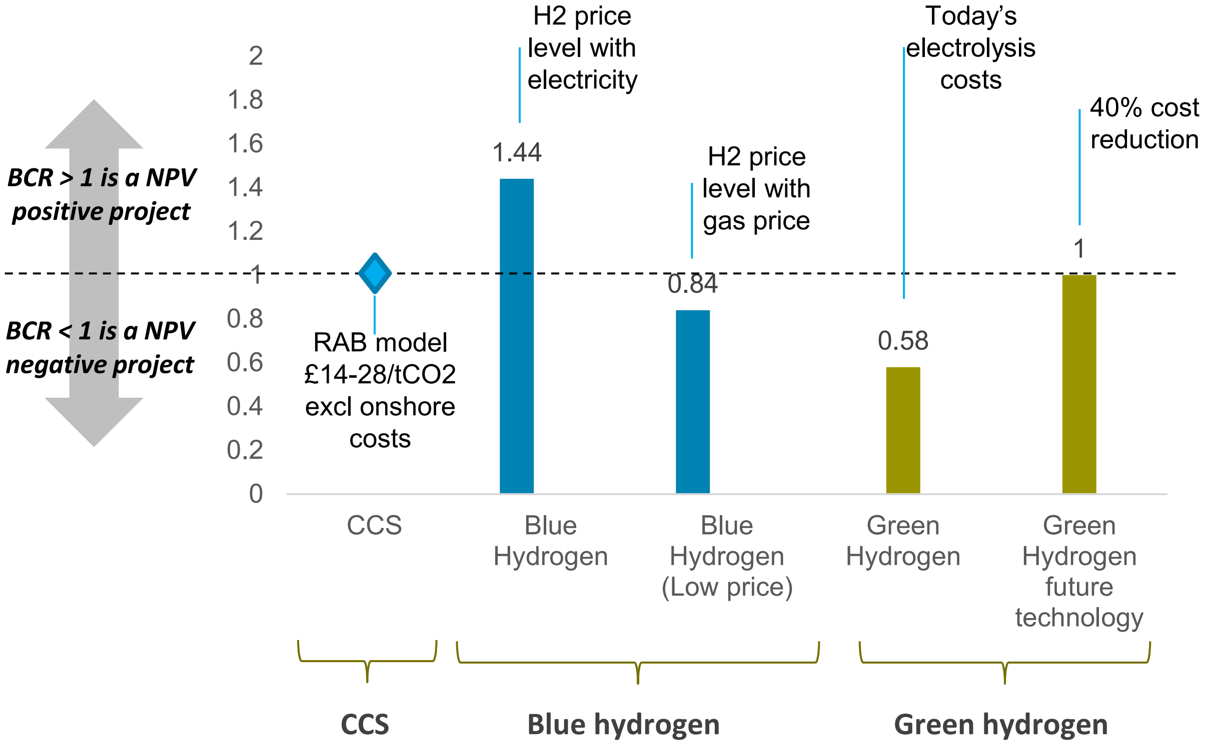
Benefit-cost ratios (BCRs) for Hydrogen models



- Hydrogen is an increasingly important energy solution to support Net Zero
- In association with CCS, hydrogen will permit a more economical decarbonisation of natural gas
- Blue hydrogen is value-enhancing when combined with CCS projects
- Green hydrogen has potential to be an efficient storage solution to deal with windpower intermittency and long-distance energy transportation
- High cost of electrolysis makes green hydrogen projects less attractive today, but costs are being reduced through technology

Regulatory analysis

Blue hydrogen regulatory findings

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Key findings:

- Blue Hydrogen production and storage principally expected to take place onshore. The principal offshore element of blue hydrogen is in the transport and storage of CO_2. The findings related to this are as per the CCUS business model.
- Blue hydrogen in combination with CCUS is an untested technology with a policy framework for deployment which is still under development. As this is developed it could affect the relevant regulatory requirements for a qualifying project
- There may be uncertainty over local planning permissions for blue and green hydrogen projects, as there is currently no guidance (eg National Planning Statements) provided for how relevant authorities should assess planning requirements or how a particular project fits within the UK's wider policy objectives. Hydrogen is prominent in the UK's industrial strategy so clarity is likely to be provided over time
- It is unclear how the threshold for nationally significant infrastructure projects (NSIP) might apply to hydrogen producers, eg whether they would be covered by definition of generating stations. The Planning Act 2008 gives power to the SoS to amend the definition of projects qualifying as a NSIP. Notional hydrogen SMR projects are expected to have a capacity equivalent of >100MW in hydrogen generation, potentially qualifying them as NSIPs.
- Similarly, in Scotland, hydrogen SMR projects will need to consider how they align with the long-term objectives and spatial plans of National Planning Framework 4
- Some requirements are shared between onshore and offshore with information that could be shared across both

Footnote: Nationally Significant Infrastructure Projects (NSIP) are major infrastructure developments in England and Wales that bypass normal local planning requirements. These include proposals for power plants, large renewable energy projects, new airports and airport extensions, and major road projects. The NSIP nomenclature began to be used in 2008, and since April 2012 these projects have been managed by the Planning Inspectorate.

Blue hydrogen – regulatory map

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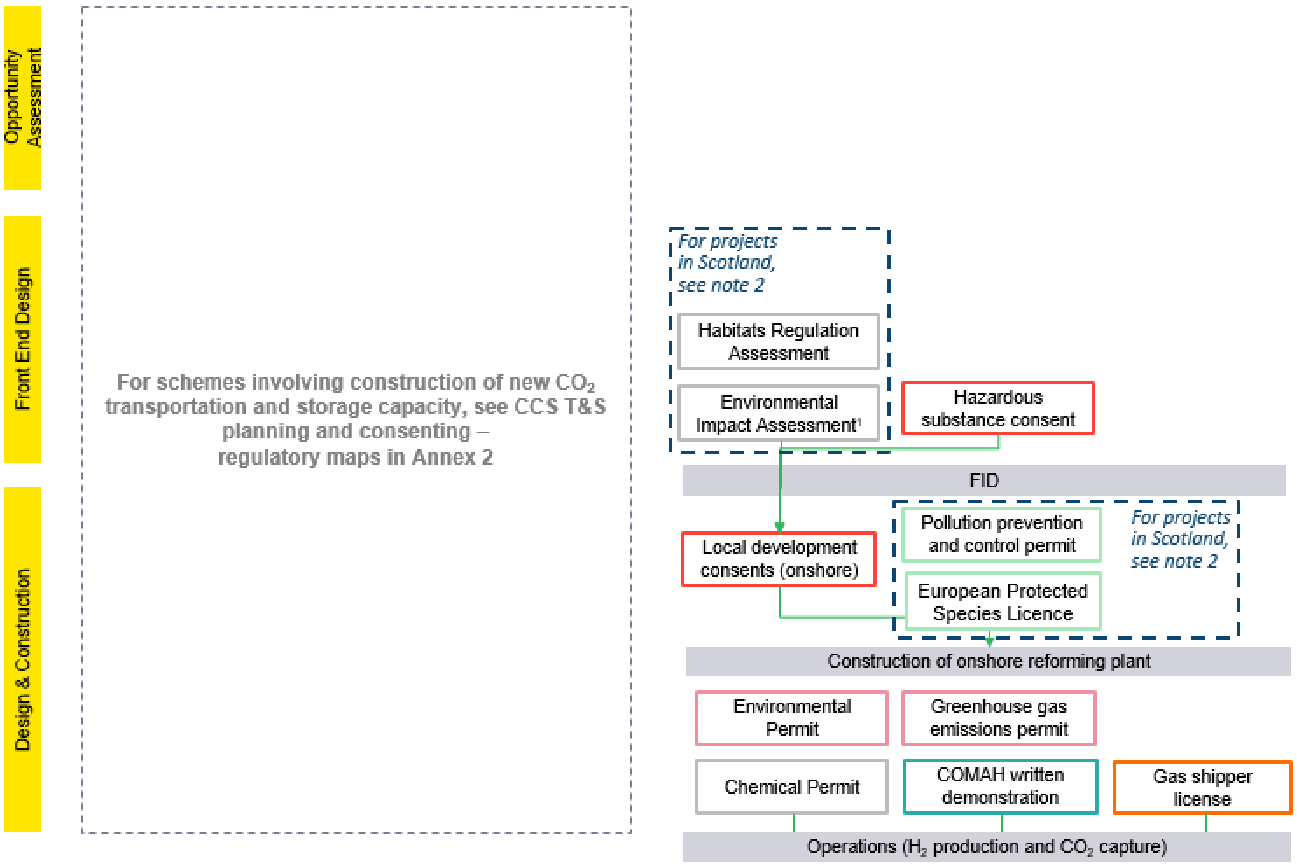

	BEIS (PINS / Welsh Ministers) In Scotland, see note 2
	Health and Safety Executive
	National Grid / SPTL / SHET
	Ofgem
	Local or Harbour Authority
	Environment Agency / SEPA
	Natural England / NRW / SNH

1 Other environmental consenting may apply if project is designated under:

- Special Areas of Conservation (SAC)
- Special Protection Areas (SPC)
- Sites of Special Scientific Interest (SSSI)
- Sites of Community Importance (SCI)
- Ramsar Sites
- Nature Conservation Marine Protected Areas (Scotland)
- Marine Conservation Zones (England and Wales)

2 Scottish Government, with statutory consultees, including:

- SEPA
- Scottish Natural Heritage (SNH)
- Local Authorities
- Maritime and coastguard agency
- Commissioners of Northern Lighthouses
- Historic Environment Scotland

Disclaimer: This map is a conceptual representation of the process for consenting and licensing a notional CCS project

Green hydrogen regulatory findings

Key findings (England / Wales):

- Green Hydrogen production and storage are principally expected to take place onshore (or on an island/hub). The principal offshore element may be in the generation of renewable electricity offshore. Projects may be developed in combination with new offshore wind.
- Green hydrogen is an emerging technology with a policy framework under development. Future policy decisions could affect the relevant regulatory requirements for a qualifying project.
- There may be uncertainty over local planning permissions, as there is currently no guidance (eg National Planning Statements) provided for how relevant authorities should assess planning requirements or how a particular project fits within the UK's wider policy objectives. Hydrogen is prominent in the UK's industrial strategy so clarity is likely to be provided over time
- The degree of regulatory complexity around green hydrogen projects may depend on whether production, transport and/or storage of the hydrogen is taking place, with greater regulatory uncertainty around how regulatory frameworks would apply to hydrogen offshore – e.g.
  - Whether a lease would be required from OGA or TCE/CES for a hydrogen pipeline
  - Whether a new hydrogen pipeline would be exempt from Marine Licence requirements, i.e. under the exemption for "gas unloading".
  - Whether O&G pipelines/terminals are being reused/repurposed for hydrogen transport, affecting safety case if converting to hydrogen, and implications for decommissioning liabilities
- It is unclear how the threshold for NSIP might apply to hydrogen producers, e.g. whether they would be covered by definition of generating stations. The Planning Act 2008 gives power to the SoS to amend the definition of projects qualifying as a NSIP. Notional hydrogen electrolyser projects are expected to have a capacity equivalent of >100MW in hydrogen generation, potentially qualifying them as NSIPs.c

Key findings (Scotland):

- Green Hydrogen production and storage are principally expected to take place onshore (or on an island/hub, such as Orkney). The principal offshore element may be in the generation of renewable electricity offshore. Projects may be developed in combination with new offshore wind.
- Green hydrogen is an emerging technology with a policy framework under development. Future policy decisions could affect the relevant regulatory requirements for a qualifying project.
- There may be uncertainty over local planning permissions, as there is currently no guidance (eg National Planning Statements) provided for how relevant authorities should assess planning requirements or how a particular project fits within the UK's wider policy objectives. Hydrogen is prominent in the UK's industrial strategy so clarity is likely to be provided over time
- The degree of regulatory complexity around green hydrogen projects may depend on whether production, transport and/or storage of the hydrogen is taking place, with greater regulatory uncertainty around how regulatory frameworks would apply to hydrogen offshore – e.g.
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  - Whether a new hydrogen pipeline would be exempt from Marine Licence requirements, i.e. under the exemption for "gas unloading".
  - Whether O&G pipelines/terminals are being reused/repurposed for hydrogen transport, affecting safety case if converting to hydrogen, and implications for decommissioning liabilities
- Hydrogen projects will need to consider how they align with the long-term objectives and spatial plans of National Planning Framework 4

Green hydrogen – regulatory map

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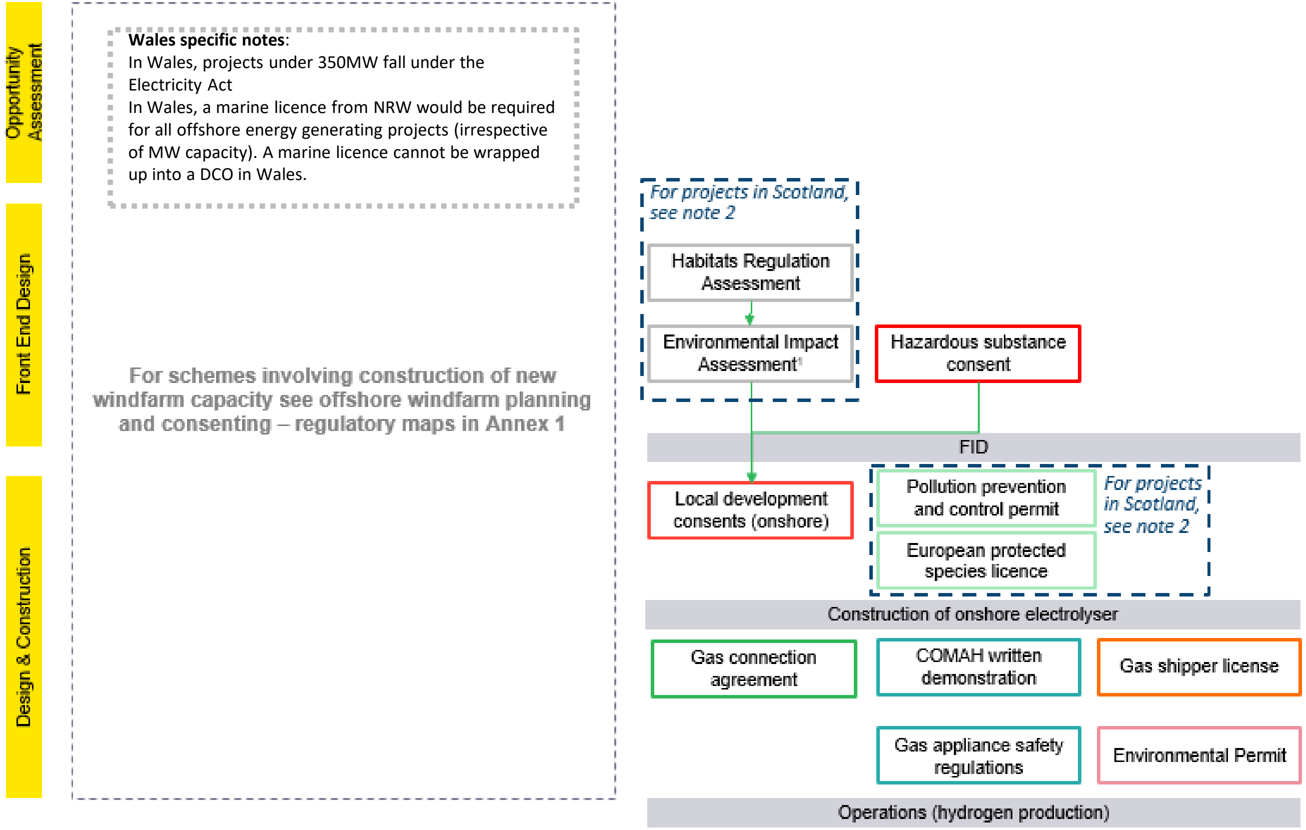

(grey)	BEIS (PINS / Welsh Ministers) In Scotland, see note 2
(teal)	Health and Safety Executive
(green)	National Grid / SPTL / SHET
(orange)	Ofgem
(red)	Local or Harbour Authority
(pink)	Environment Agency / SEPA
(light green)	Natural England / NRW / SNH

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- Historic Environment Scotland

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Appendix

Appendix – references

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UK Industrial Strategy / Clean Growth Strategy

- Industrial Strategy the Grand Challenges: Clean Growth
https://www.gov.uk/government/publications/industrial-strategy-the-grand-challenges/industrial-strategy-the-grand-challenges#clean-growth

- The UK Clean Growth Strategy
https://www.gov.uk/government/publications/clean-growth-strategy

- Industrial Strategy: Clean Growth – Industrial Clusters mission
https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/803086/industrial-clusters-mission-infographic-2019.pdf

- Industrial Strategy Challenge Fund – Industrial Decarbonisation
https://www.ukri.org/innovation/industrial-strategy-challenge-fund/industrial-decarbonisation/

Low-Carbon Hydrogen Supply

- BEIS Low-Carbon Hydrogen Supply Competition

- Phase 1 - Low carbon hydrogen could play an important role in decarbonising industry, power, heat and transport. However, for a market to grow, potential users (in any application) need to be confident in supply of sufficient amounts of low carbon hydrogen at a competitive price. The £33 million Low Carbon Hydrogen Supply competition aimed to accelerate the development of low carbon bulk hydrogen supply solutions in the above sectors. It was aimed at projects at a technology readiness level (TRL) of 4 to 7, which could result in lower capital or operating costs when compared to Steam Methane Reformation with Carbon Capture & Storage (SMR+CCS), or improve the carbon capture rates at a comparable cost.
https://www.gov.uk/government/publications/hydrogen-supply-competition

- Phase 2 of the competition aimed to accelerate the development of low carbon bulk hydrogen supply solutions by providing funding for demonstration projects - https://www.gov.uk/government/publications/hydrogen-supply-competition/hydrogen-supply-programme-successful-projects-phase-2

Appendix – references

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Industrial Fuel Switching

- BEIS Industrial Fuel Switching competition - to bring technologies switching energy-intensive processes away from current fossil fuels closer to commercial application.
- Phase 1 – Study commissioned to Element Energy and Jacobs to explore the potential for industries to switch to biomass, hydrogen and electric technologies and identify constraints and opportunities to realise this potential Ph1 report (2018)
- Phase 2 – up to £300,000 for feasibility studies looking into developing technologies (TRL 4-7) Phase 2 closed to applications in February 2019. The reports from these studies are available on this page Ph2 reports
- Phase 3 – demonstration projects which would result in the implementation and demonstration of a process or technology to switch to low carbon fuel sources. It closed to applications in October 2019. Contract values awarded of £2.8 to 7.8m to the following projects

Hydrogen Transport & Distribution

- Ofgem, National Grid Gas Transmission (NGGT), and various UK utilities are investigating ways to transport and distribute hydrogen
- NGGT has ongoing programmes to demonstrate ways to safely transport hydrogen in the National Transmission System (NTS) and potential for repurposing Hydrogen National Transmission System (HyNTS) programme including;
- Project Cavendish (slide 9) exploring ways to produce, store or import hydrogen at the Isle of Grain in Kent to get hydrogen to the South of London
- Aberdeen Vision to provide a case for constructing a hydrogen pipeline between St Fergus and Aberdeen that would initially supply the network with a hydrogen blend of up to 20%, increasing to 100%
- FutureGrid bid submitted to Ofgem as part of NIC 2020 by NGGT, Northern Gas Networks (NGN) and Fluxys Belgium to build a hydrogen test facility from decommissioned assets in Cumbria
- Other projects include hydrogen deblending that would allow feeding a mix of hydrogen and methane through the network, and then deblending the hydrogen to supply areas that are ready to switch with only hydrogen, while continuing to supply other areas with only methane or a specific blend of the two gases
- H21 , pilot project to convert UK's gas distribution networks from natural gas to 100% hydrogen. Partners include the UK gas networks (Northern Gas Networks, Cadent, SGN and Wales & West Utilities), HSL and DNV-GL. The H21 North of England, a strategic report presenting a conceptual design for converting the gas networks of the North of England to hydrogen between 2028 and 2035
- H100 Fife : pilot to create the first hydrogen heating network for domestic and business customers by SGN

Appendix – methodology & assumptions

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Methodology, assumptions and sources
Economic modelling • Technologies are compared in terms of BCRs and levelised costs • Model economics are real and pre-tax • Offshore projects' scope is discounted at 10% (real) • Hydrogen onshore processing is discounted at 5% (real) • Electricity transmission infrastructure is discounted at 2.9% (real, from recent cases)
Energy parameters and conversion factors • UK offshore windpower commercial load factors 39%-47% (2019 BEIS, DNV GL) • Hydrogen energy density 39kWh/kg (HHV) and 33kWh/kg (LHV) • Natural gas energy density 14.5kWh/kg (HHV) and 13.1kWh/kg (LHV) • Blue hydrogen (methane reforming) energy efficiency 70-75% (NG FES) • Green hydrogen (electrolysis) electricity efficiency 70-80% (Various) • H2 price: 53 £/MWh (parity with electricity wholesale price) • Equivalent to: 2.08 £/KgH2 Less transmission losses: 1% • Electricity sale price: 53 £/MWh (wholesale), Less Network charges: 6.74 £/MWh, Less Transmission losses: 8% • Windfarm capacity: GW+, able to supply 250MW continuously • Additional electricity for sale: 2.19 TWh/yr • Curtailment: 25% of the above is not sold

Acronyms and abbreviations	
BEIS	Department for Business, Energy and Industrial Strategy
BOE	Barrel of oil equivalent
BECCS	Bio-Energy Carbon Capture and Storage
CCC	Committee on Climate Change
CCS	Carbon Capture and Storage
CCUS	Carbon Capture Utilisation and Storage (in this report, same as CCS)
CES	Crown Estate Scotland
CO2e	Carbon Dioxide equivalent
EIP	Energy Integration Project
GHG	Green-house gases
HC	Hydrocarbon
HHV	High Heating Value = LHV + heat of products vaporisation
LCOT	Levelised Cost of Transport (CCS T&S)
LHV	Low Heating Value
NG ESO	National Grid Electricity System Operator
NG FES	National Grid ESO Future Energy Scenarios
OCGT	Open Cycle Gas Turbine generator
OGA	Oil and Gas Authority
OGTC	Oil and Gas Technology Centre
OGUK	Oil and Gas UK
PEM	Proton Exchange Membrane (electrolysis)
SG	Scottish Government
T&S	Transport and Storage (of CO2)
TCE[1]	The Crown Estate
tCO2	Tonnes of Carbon Dioxide
UKCS	UK Continental Shelf
UKRI	UK Research and Innovation
WACC	Weighted averaged cost of capital

1) The Crown Estate manages the seabed around England, Wales and Northern Ireland and provides leases/licences for offshore energy, marine aggregates and cables and pipelines. It is not a regulator, however, for the purpose of this report, it may be grouped together with regulators

Appendix – methodology & assumptions

Oil & Gas Authority

Methodology, assumptions and sources
UK GHG emission profile • BEIS reported 2018 UK GHG emissions of 451.5 MtCO2e used as starting point • Projected GHG emission reductions until 2032 according to the fourth and fifth UK Carbon Budgets • From 2033, GHG emissions decline linearly to net zero in 2050 • The potential contribution of individual offshore technologies to GHG abatement was modelled according to the methodology below:
CCS and Blue Hydrogen outlooks • BEIS *UK CCUS deployment pathway* (2018) estimated ca. 130MtCO2 p.a. of negative emissions technologies needed to reach net zero emissions in 2050 • CCC's report *Net Zero: The UK's contribution…* (2019) estimated up to 175 MtCO2 emissions p.a. to be abated through CCS by 2050, of which 125MtCO_2 from Blue-H2 and combustion sources (power and industrial) • NG FES *Two Degrees* case (2019) projects a conversion of 377 TWh of natural gas p.a. (or 28% of UK's demand today) to Blue-H2 by 2050, a process which generates 70MtCO2 p.a. to CCS • As a result we projected CO_2 injection rate growing to 130 MtCO2 p.a. by 2050, with a 70-60 CO_2 source split between Blue-H2 and post-combustion capture (power and industrial) • The rate of growth reflects initial pilot-scale projects deployed in the 2020s, followed by a linear progression of commercial scale plants in the 2030/40s

Methodology, assumptions and sources
Green Hydrogen outlook • Our 'Low case' considers NG FES '2 Degree' scenario of 70GW offshore windpower capacity in 2050; applying a 44% load factor, we assumed 25% of electricity would generate 47TWh p.a. of Green-H2 to mitigate intermittency • Our 'High case' considers the CCC recommendation of 75GW offshore windpower capacity in 2050; applying a 58% load factor, we assumed 40% of electricity would generate 106TWh p.a. of Green-H2 to mitigate intermittency