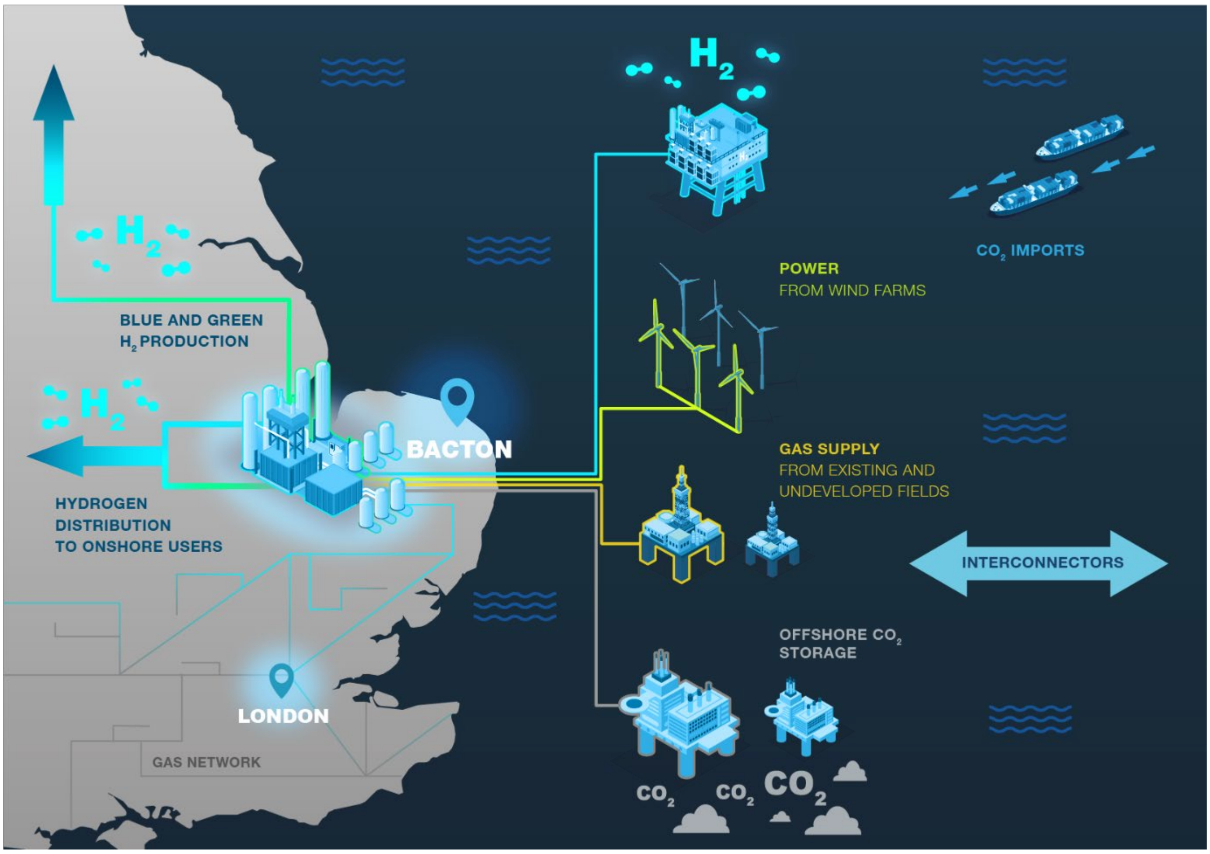
Bacton Energy Hub

Hydrogen Supply SIG – Summary Report



Summit Energy Evolution Ltd

Rev	Date issued	Reason for issue	Prepared	Checked	Approved
A	30/09/2022	First Draft	S J Palmer	P Lafferty	P Lafferty
0	07/10/22	SEEL Commented	S J Palmer	P Lafferty	P Lafferty
1	12/10/22	SIG Comments Added	S J Palmer	P Lafferty	P Lafferty

Date:

This page is intentionally left blank.

Contents

1 Executive Summary 4

2 Introduction and Objectives 5

2.1 Introduction 5

2.2 Objectives (Supply SIG) 6

2.3 Base Case Development Scenario 6

3 Work summary 7

3.1 Production Profiles 7

3.2 Production Phasing 8

3.3 Power Demand Strategy 9

3.4 Electrolytic Hydrogen Facility Scoping Design 14

3.5 Water Supply and Desalination Requirements 19

3.6 Production Technology Review 21

3.7 CCS Feasibility 26

4 Costs and Economics 28

5 Risks Assessment 30

6 Conclusions and Recommendations 32

1 Executive Summary

Bacton is ideally positioned to become a significant hydrogen production facility for London and the South East primarily due to its access to natural gas for blue hydrogen production, its access to offshore wind farms for green hydrogen production, good regional gas connections and access to offshore structures for carbon dioxide and hydrogen injection and storage. The Bacton Energy Hub (BEH) study incorporates a number of work streams to undertake an initial technical and commercial feasibility assessment of the scheme based upon a number of development scenarios. The work has been divided into a number of Special Interest Groups (SIGs) covering Demand, Supply, Infrastructure, Supply Chain and Technology and Regulatory. The Supply SIG work has been further sub-divided as indicated hereunder with specialist companies providing the assessment:

- Gas production (TotalEnergies/Woodmac)
- Hydrogen production phasing (Fluor)
- Blue Hydrogen Technology Review (Progressive Energy)
- Green Hydrogen Scoping Definition Report (Genesis)
- Green Hydrogen Technology Review (Genesis)
- Power demand (Saipem)
- Water Supply and Desalination (Goal7/Neptune Energy)
- CCS Feasibility (OPC/Neptune Energy)
- Cost Estimating and Economic Modelling (IO/SEEL)

The high level timeline assumptions for the BEH are as follows:

- 2025 FID, 2030 first hydrogen (CCS enabled) production;
- 2040 build-out initial phase complete including first electrolytic hydrogen production;
- 2050 build-out final phase complete with 100% electrolytic hydrogen.

Some of the key findings from the work undertaken within the Supply SIG include the following:

- Forecast SNS gas supply for CCS enabled hydrogen production will be sufficient to service a plant capacity of c. 1GW (3 x 355MW SMR/ATR plant assumption) to around 2040 and provide the earliest means of supporting carbon sequestration, after this imported gas or LNG will be required to supplement/replace supply;
- Legislative and regulatory support may be required to realise CCS enabled hydrogen economies of scale from the large capacity projects as these can be offset by the increased feed gas requirements. The increased cost of feed gas at scale is exacerbated at higher natural gas prices and interconnector price premiums if domestic natural gas supply is insufficient by 2040;
- The key uncertainties that impact the CCS enabled hydrogen levelised cost are feed gas cost, CCS pricing and the cost of grid electricity;
- Energy supply pricing for the electrolytic hydrogen options also requires further review and sensitivity modelling; adopting alternative assumptions to reflect future techno-commercial advancements could have a significant positive effect on LCOH;
- Methods of addressing the intermittency of offshore wind power require further review, hydrogen storage and the potential of CCS enabled hydrogen supplementary production should be included;
- A new desalinated water supply will be required and there may be synergies to supply water to East Anglian Water due to forecast supply issues;
- There is possibly sufficient space at the Bacton terminal for at least 1 x 355 MW CCS enabled hydrogen facility. Terminal rationalisation and/or extension is likely to be required for larger deployment of CCS enabled and/or electrolytic hydrogen facilities
- The possible provision of alternative offshore facilities for electrolytic hydrogen production tied back to Bacton via an existing unused pipeline system should be reviewed;

The development of CCS facilities to support CCS enabled hydrogen production appears likely to be available in region and generally progressing within the required timeline.

2 Introduction and Objectives

2.1 Introduction

In 2021 the UK Oil & Gas Authority (OGA), now the UK North Sea Transition Authority (NSTA) commissioned Progressive Energy to develop a future vision for the Southern North Sea and Bacton considering the role of hydrogen in supporting the delivery of Maximising Economic Recovery (MER UK) and Net Zero. The study and report identified the directional value-add that hydrogen could unlock and the potential to create a Bacton Energy Hub centred around CCS enabled and electrolytic hydrogen production in the Bacton Area.

Bacton is ideally positioned to become a significant hydrogen production facility for London and the South East. It has a number of critical advantages:

- Access to indigenous and, later, imported natural gas for CCS enabled hydrogen production
- Access to offshore wind farm output for electrolytic hydrogen production
- Availability of offshore structures for carbon dioxide (CO2) and hydrogen (H2) storage
- Land for development of hydrogen production
- Excellent gas connections to London and the South East of England
- Interconnectors (import and export services)

The overriding key driver for the project has been determined to be:

"Establish a sustainable hydrogen system to ensure Bacton remains a key regional Energy Hub with a low carbon future"

This driver for the overall development of the hub is supplemented by the following statement for this feasibility phase of the project:

"To work towards building a foundation on which a credible project can emerge"

In addition, the following need to be considered as key factors for the project:

- To design, build and operate facilities that are safe and reliable, that have minimal emissions and respect all stakeholders associated with the project
- Minimising cost in CAPEX, OPEX and ABEX to ensure the project economics are as attractive as possible
- Maintaining a schedule that is timely and opportune for delivering hydrogen production and CCS facilities in a reasonable timescale to fulfil market requirements and government commitments
- To be scalable and allow maximum growth over the lifetime of the development to help meet the energy transition needs for hydrogen production in the South and East of England

The scope of work for the feasibility phase of the project has been divided into 5 no. SIG's as presented in the organisation chart below.

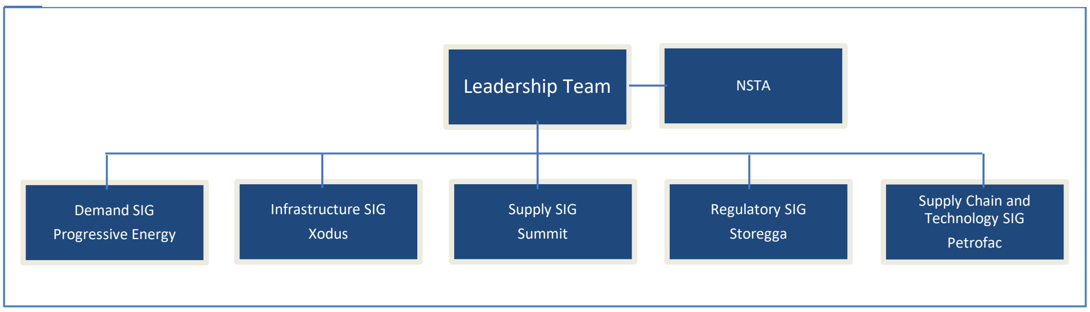


Figure 2.1 - BEH SIG Organisation Chart

2.2 Objectives (Supply SIG)

A Project Execution Plan has been prepared for the Supply SIG feasibility work, this includes a Terms of Reference which summarises the objectives and goals as presented hereunder.

For these feasibility studies the Supply SIG considered both CCS enabled and electrolytic and hydrogen and addressed the following key aspects and objectives:

- Principle technologies to deliver a cost competitive hydrogen fuel at scale from Bacton by at least 2030;
- Hydrocarbon feedstock for CCS enabled hydrogen production and power requirements;
- Feedstock for electrolytic hydrogen (incl. renewable power supply and desalinated water);
- CCS storage for hydrogen production;
- Hydrogen storage (requirements determined by Demand SIG);
- Blending (requirements defined under Demand SIG);
- Phasing and timing for CCS enabled and electrolytic hydrogen.
- Identifying the optimum cost competitive hydrogen production technologies to meet the hydrogen demand forecast;
- Identifying key technology providers;
- Generating a set of assumptions to take forward into subsequent project phases;
- Developing an economic model for the hydrogen production concepts and LCOH.

2.3 Base Case Development Scenario

It is recognised that there are a multitude of scenarios that are credible, however detailed scenarios will ultimately be required to be explored by the consortium in the future phases of the project. The decision has therefore been taken to focus this phase of the project on two key grounding scenarios:

- **Core Project**: which aims to represent the minimum potential / minimum value proposition of a hydrogen hub at Bacton.
- **Build Out:** which aims to represent how you would build from the minimum potential to a hub which delivers what we believe is a base case analogous with a P50 development case.

The general assumptions, requirements and key technical data for the Core Project and Build Out scenarios relevant to the Supply SIG activities are presented in Table 2.1 below, a more comprehensive table including Demand and Infrastructure details is included within Appendix 1.

Description	Core Project	Build-out
Supply Base Assumption	CCS Enabled hydrogen	CCS Enabled & Electrolytic H2
CCS Enabled & Electrolytic H2 Phasing	1 or 3 (depending upon demand) x 355MW SMR/ATR plants	2030 – 3 x 355MW SMR/ATR plants
		2040 - 3 x 355MW SMR/ATR plants 2 x 1.8GW upscaled SMR/ATR plants + 1 x 2.1 GW Electroliser
		2050 - 2 x 1.8GW upscaled SMR/ATR plants 1 x 2.1 GW Electroliser + 2 x 2.1 GW Electroliser (3 x 355MW plants retired)
Max. supply from CCS enabled hydrogen TWh & (% of demand)	1 plant - 3 TWh – (100% of demand)	2030 – 9 TWh (100%) 2040 – 39 TWh (54%) 2050 – 30 TWh (33%)
Max. supply from Electrolytic hydrogen TWh & (% of demand)	Zero	2030 – 0 TWh (0%) 2040 – 18 TWh (46%) 2050 – 54 TWh (80%)

Table 2.1 – Supply Assumptions for Development Scenarios

3 Work summary

3.1 Production Profiles

Wood Mackenzie were commissioned to carry out a short study to assess gas supply through Bacton to support the broader BEH analysis. The study developed Low, Base Case, and Incremental Case forecasts as presented in Figure 3.1:

- Low Case: A ‘minimum’ case considering production onstream and under development
- Base Case: The Low Case with the addition of commercial discoveries
- Incremental Case: The Base Case with the addition of reserves growth and Yet To Find volumes

It should be noted that these estimates exclude Interconnector gas volumes.

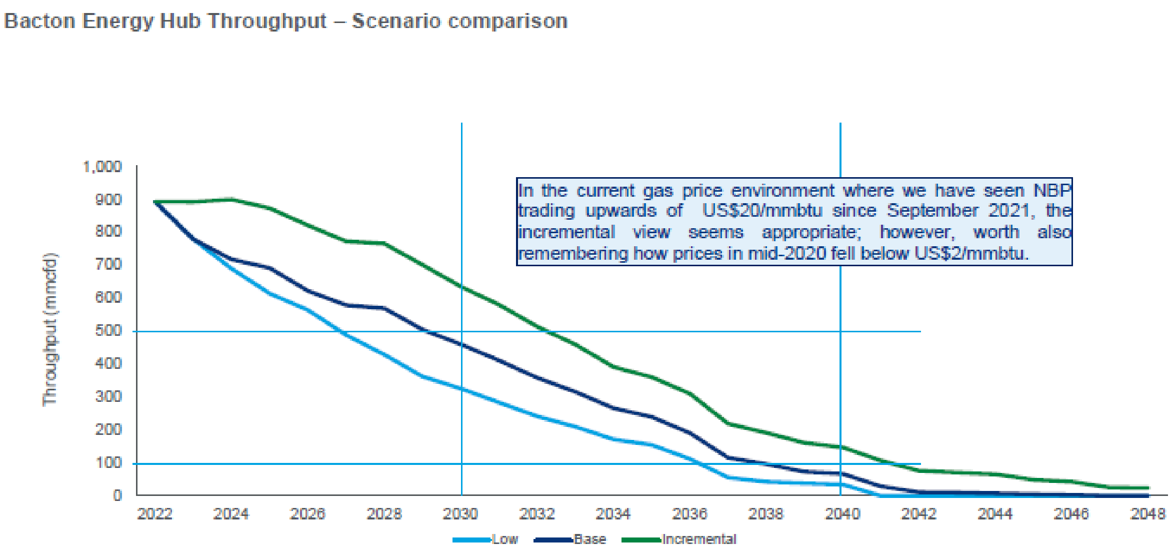


Figure 3.1 – Bacton Gas Supply Forecasts (excl. Interconnectors)

The Incremental Case is presented in Figure 3.2 over and although it the most optimistic of the three cases, it is considered by Wood Mac to be the most representative for future domestic supply into Bacton especially given the current gas price outlook. It should be noted that during 2022 there were approximately 30 no. fields on stream but that 6 no. were contributing over 60% of production; gas supply is therefore somewhat sensitive to the latter.

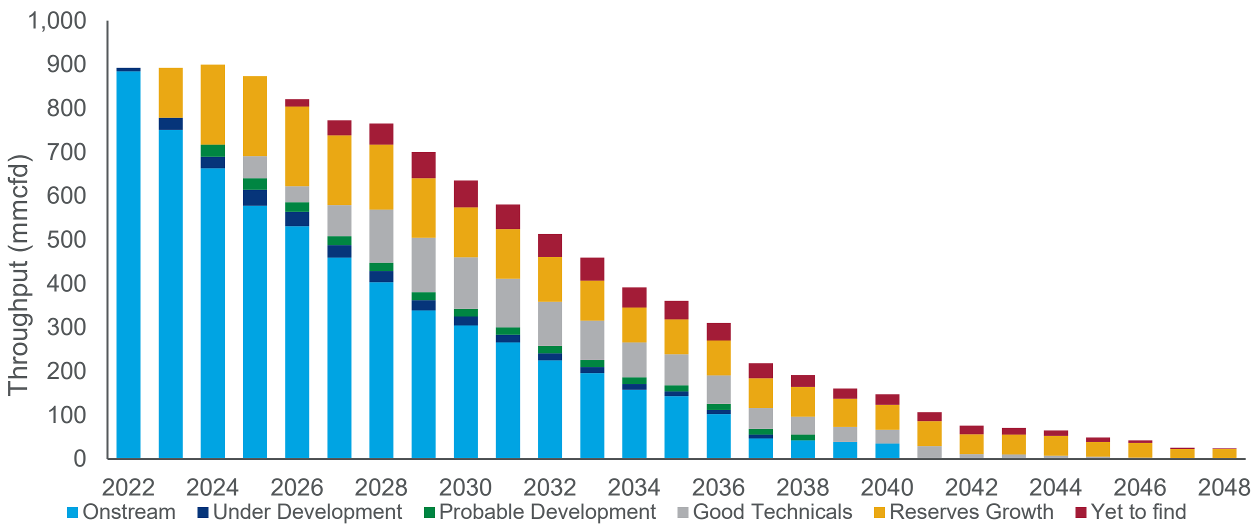


Figure 3.2 – Bacton Gas Throughput (Incremental Case)

The base case development scenarios consider 355 MW CCS enabled plants, 1 no. for the Core Project in 2030 and 3 no. for the Build-out case in 2030. For the CCS enabled hydrogen option gas supply requirements are of the order of 30mmcfd per plant. Based upon the profiles within Figure 3.1, gas supply will drop below 100mmscfd for the Low Case in c. 2037 but extended out to c. 2042 for the Incremental Case. For the Build-out Case therefore, CCS enabled hydrogen plant can rely on domestic gas supply through Bacton up until c. 2040, thereafter imported gas would be required from, for example, the interconnector(s) or LNG. This also assumes that the hydrogen plant is commercially competitive through for example a CfD structure or takes priority over gas supply.

It should be noted that changes in gas demand by major consumers that may have completed an energy transition process could supplement gas supply. Additionally, by 2030 it may be that some levelling of the production profile could be achieved through capping of production outputs but there is no mechanism currently in place to achieve this so this concept has not been considered.

3.2 Production Phasing

There are several elements to project phasing which need be considered and further work is required to assess the dynamic nature of some of the schedule drivers to better determine potential development scenarios. The initial development is focused on CCS enabled hydrogen and depending upon a number of factors, there may be a case for considering a lower capacity early production scenario transitioning to a phased electrolytic hydrogen development. If it were possible to extend/constrain the profiles presented in 3.1 above there could be a role for blue hydrogen to assist in addressing the intermittency of offshore wind powered electrolytic hydrogen production. Supply chain engagement is key in any further review of production phasing, in particular for offshore wind developments.

The study has identified one of the most significant phasing factors to be layout requirements for future build out cases. If the development is constrained to the use of the existing Eni plot, this will ultimately limit the scale of the facilities. It should also be noted that although the Eni site is relatively clear, this is a brownfield site and no assessment has been made or is available at present to understand any underground systems that may still be remaining from the abandoned plant. A further consideration is the proposed location(s) for future CCS facilities and any competition this may present for land in the Bacton area.

The study has shown that the Core Project could potentially be sited in the existing Bacton area. Footprints were matched against the source data by Supply SIG members in terms of CCS-Enabled H2, electrolytic hydrogen production, power infrastructure and desalination using the existing plot area as a basis. Lay down area for plant construction has been considered but additional space would need to be acquired for the period of construction, this has yet to be determined and remains to be addressed.

The map and plot overlay overleaf show the core project. It is clear that any project Build-out case will require additional real estate. A major issue therefore for any of the build-out scope is the requirement for additional land and the associated land permitting and acquisition requirements.

Figure 3.3 – Core Project Location

A SIMOPS Review was undertaken which included representatives from Bacton plant operations and engineering construction companies. A premise to the SimOps was that to achieve execution of the Core Project and Build-Out, the BEH development will require extensive assessment (Safety, Planning, Engineering, Construction) of the existing facilities and associated interfaces, optimization of plant and processes, determination of execution methodology and must seek and obtain the requisite planning consents. A key element will be simultaneous construction and existing plant operations. A further observation is that site constraints related to personnel numbers, laydown requirements and logistics may require a more modularized approach is required for the execution methodology.

3.3 Power Demand Strategy

3.3.1 Power Demand

The work scope required a review of the power demand requirements for CCS enabled and electrolytic hydrogen facilities and onshore CCS facilities, and then determine a suitable source of power including grid supply and dedicated renewable power.

- Power consumption inputs were taken from the relevant reports and used to establish power demands for the different development scenarios, these are summarised in Table 3.1 over.

Facility	Process	Electrical Consumption	Reference
CCS enabled H2 (Inc. CCS)	CCS Enabled	79 kWe/MWth	CCS enabled Hydrogen Report [Ref 1], 25-30MW net grid import for a 350MWth unit. Note (1).
Desalination	SWRO (2-stage)	4.4 kWhe/m^3	Desalination Report [Ref 3], Table 5-2. Note (2).
Electrolytic H2	Alkaline Electrolyser	2,100 Mwe	Electrolytic Hydrogen Report [Ref 2], Table 4-2

Table 3.1 - Facilities Power Consumption Duties

The tables presented hereunder provide estimated power demand lists broken down by process and development scenario.

COD	PROCESS	SUB-PROCESS	PLANT	NAMEPLATE	Demand [Mwe]
2030	CCS enabled H2	Production & CCS	CCS enabled PLANT 1	355 MWth	28
2030	CCS enabled H2	Desalination	SWRO PLANT 1	45 m^3/h	0.20

Table 3.2– Total Core Project electrical demand list

COD	PROCESS	SUB-PROCESS	PLANT	NAMEPLATE	Demand [Mwe]
2030	CCS enabled H2	Production & CCS	CCS enabled Plant 1	355 MWth	28
2030	CCS enabled H2	Production & CCS	CCS enabled Plant 2	355 MWth	28
2030	CCS enabled H2	Production & CCS	CCS enabled Plant 3	355 MWth	28
2030	CCS enabled H2	Desalination	SWRO PLANT 1	45 m^3/h	0.20
2030	CCS enabled H2	Desalination	SWRO PLANT 2	45 m^3/h	0.20
2030	CCS enabled H2	Desalination	SWRO PLANT 3	45 m^3/h	0.20

Table 3.3– Total Build-out 2030 electrical demand list

2030	CCS enabled H2	Production & CCS	CCS enabled Plant 1	355 MWth	28
2030	CCS enabled H2	Production & CCS	CCS enabled Plant 2	355 MWth	28
2030	CCS enabled H2	Production & CCS	CCS enabled Plant 3	355 MWth	28
2030	CCS enabled H2	Desalination	SWRO PLANT 1	45 m^3/h	0.2
2030	CCS enabled H2	Desalination	SWRO PLANT 2	45 m^3/h	0.2
2030	CCS enabled H2	Desalination	SWRO PLANT 3	45 m^3/h	0.2
COD	**PROCESS**	**SUB-PROCESS**	**PLANT**	**NAMEPLATE**	**Demand [Mwe]**
2040	CCS enabled H2	Production & CCS	CCS enabled Plant 4	1800 MWth	141
2040	CCS enabled H2	Production & CCS	CCS enabled Plant 5	1800 MWth	141
2040	CCS enabled H2	Desalination	SWRO PLANT 4	228 m^3/h	1.0
2040	CCS enabled H2	Desalination	SWRO PLANT 5	228 m^3/h	1.0
2040	Electrolytic H2	Production	ALKALINE ELECTROLYSER 1	2100 Mwe	2100
2040	Electrolytic H2	Desalination	SWRO PLANT 6	378 m^3/h	1.7

Table 3.4 – Total Build-out 2040 electrical demand list

COD	PROCESS	SUB-PROCESS	PLANT	NAMEPLATE	Demand [Mwe]
2030	CCS enabled H2	Production & CCS	CCS enabled Plant 1	355 MWth	*0 (RETIRED)*
2030	CCS enabled H2	Production & CCS	CCS enabled Plant 2	355 MWth	*0 (RETIRED)*
2030	CCS enabled H2	Production & CCS	CCS enabled Plant 3	355 MWth	*0 (RETIRED)*

2030	CCS enabled H2	Desalination	SWRO PLANT 1	45 m^3/h	*0 (RETIRED)*
2030	CCS enabled H2	Desalination	SWRO PLANT 2	45 m^3/h	*0 (RETIRED)*
2030	CCS enabled H2	Desalination	SWRO PLANT 3	45 m^3/h	*0 (RETIRED)*
COD	**PROCESS**	**SUB-PROCESS**	**PLANT**	**NAMEPLATE**	**Demand [Mwe]**
2040	CCS enabled H2	Production & CCS	CCS enabled Plant 4	1800	141
2040	CCS enabled H2	Production & CCS	CCS enabled Plant 5	1800	141
2040	CCS enabled H2	Desalination	SWRO PLANT 4	228 m^3/h	1.0
2040	CCS enabled H2	Desalination	SWRO PLANT 5	228 m^3/h	1.0
2040	Electrolytic H2	Production	ALKALINE ELECTROLYSER 1	2100 Mwe	2100
2040	Electrolytic H2	Desalination	SWRO PLANT 6	378 m^3/h	1.7
COD	**PROCESS**	**SUB-PROCESS**	**PLANT**	**NAMEPLATE**	**Demand [Mwe]**
2050	Electrolytic H2	Production	ALKALINE ELECTROLYSER 2	2100 Mwe	2100
2050	Electrolytic H2	Production	ALKALINE ELECTROLYSER 3	2100 Mwe	2100
2050	Electrolytic H2	Desalination	SWRO PLANT 7	378 m^3/h	1.7
2050	Electrolytic H2	Desalination	SWRO PLANT 8	378 m^3/h	1.7

Table 3.5 – Total Build-out 2050 electrical demand list

3.3.2 Power Supply

It is assumed that the supply of power would be split between the regional power grid supplying BEH requirements except for the electrolytic hydrogen electrolysers, the latter would be supplied from a dedicated offshore wind resource based upon the following:

Once power has entered the grid it is generally considered more economical and efficient to be consumed by grid users than converted to hydrogen;

The large power requirement of the electrolysers (c. 6.6GW by 2050) may make total supply from the grid unfeasible;

Offshore wind is probably the best means of meeting large scale power demands and Bacton's location is advantaged by being near existing and likely future offshore wind developments;

Power supply to the grid from wind farm connections may also be a consideration depending upon the supply and demand profiles.

An overview of the power supply allocation is presented in the table below.

COD	PROCESS	PLANT	Demand [MWe]	SUPPLY SOURCE
2030	CCS enabled H2	CCS enabled Plant 1 [355MWth]	28	GRID
2030	CCS enabled H2	CCS enabled Plant 2 [355MWth]	28	GRID
2030	CCS enabled H2	CCS enabled Plant 3 [355MWth]	28	GRID
2030	CCS enabled H2	SWRO PLANT 1 [45m^3/h]	0.2 0	GRID
2030	CCS enabled H2	SWRO PLANT 2 [45m^3/h]	0.2 0	GRID
2030	CCS enabled H2	SWRO PLANT 3 [45m^3/h]	0.2 0	GRID
2040	CCS enabled H2	CCS enabled PLANT 4 [1800MWth]	14 1	GRID
2040	CCS enabled H2	CCS enabled PLANT 5 [1800MWth]	14 1	GRID
2040	CCS enabled H2	SWRO PLANT 4 [230m^3/h]	1.0	GRID
2040	CCS enabled H2	SWRO PLANT 5 [230m^3/h]	1.0	GRID
2040	Electrolytic H2	ALKALINE ELECTROLYSER 1 [2100MWe]	22 00	OFFSHORE WIND + GRID
2040	Electrolytic H2	SWRO PLANT 6 [380m^3/h]	1.7	GRID
2050	Electrolytic H2	ALKALINE ELECTROLYSER 2 [2100MWe]	22 00	OFFSHORE WIND + GRID
2050	Electrolytic H2	ALKALINE ELECTROLYSER 3 [2100MWe]	22 00	OFFSHORE WIND + GRID
2050	Electrolytic H2	SWRO PLANT 7 [380m^3/h]	1.7	GRID
2050	Electrolytic H2	SWRO PLANT 8 [380m^3/h]	1.7	GRID

Table 3.6 – Power Supply List

A number of grid and offshore wind power supply scenarios were considered. A base case for grid power to the H_2 electrolysers was derived where 130MW and 400MW connections are made between the grid and the electrolysers for the 2040 and 2050 build-out phases respectively. This scenario is foreseen to allow for a nominal supply of power from the grid to help stabilise the operations of the electrolysers. This is c.10% of the average power anticipated from offshore wind farms, based on a 60% capacity factor.

The connection capacities (130MW by 2040 and 400MW by 2050), are considered to be feasible in terms of grid power availability and local infrastructure capacity.

Power connections for the different development phases were considered but are indicative pending further work including capacities, voltage levels, sub-station locations, network upgrades etc. It can be assumed that a significant proportion of the UK's renewable energy generation would originate from offshore wind in the southern North Sea and would therefore be available for the Bacton Energy Hub.

For the core project and 30MW connection, a connection request was made to UK Power Networks; the nominated point of connection substation is Earlham Grid (132kV) located about 38km from the BEH site and the cost of this connection is estimated to be around £37.4m.

There are apparently short- and long-term plans to upgrade and reinforce the national grid network in East Anglia. The current export capacity of the grid in East Anglia is around 3.5GW, and the network operator plans to expand this to between 10-17GW in the coming ten years. This is primarily due to the anticipated increase in power generation that will connect into the grid at this region. The increased generation would come from offshore wind, nuclear and interconnections.

The significant increase in offshore wind power capacity in the SNS and associated grid upgrade work may provide the BEH with a robust power supply foundation provided its integration within third party development plans is progressed. However, this needs further detailed review as infrastructure upgrades may be critical and the cost and schedule implications would be key considerations.

The intermittency of supply from offshore wind farms for the electrolytic hydrogen scenarios needs careful consideration and by what means this will be mitigated; grid connected power will need to be part of this assessment.

3.4 Electrolytic Hydrogen Facility Scoping Design

3.4.1 Overview

Genesis has provided a 'scoping level design' for a 2.1 GW electrolytic hydrogen facility. This provides scoping definition for the build-out cases for the BEH development scenarios and provides input for other SIG work. A system flow diagram indicating facility battery limits is presented over.

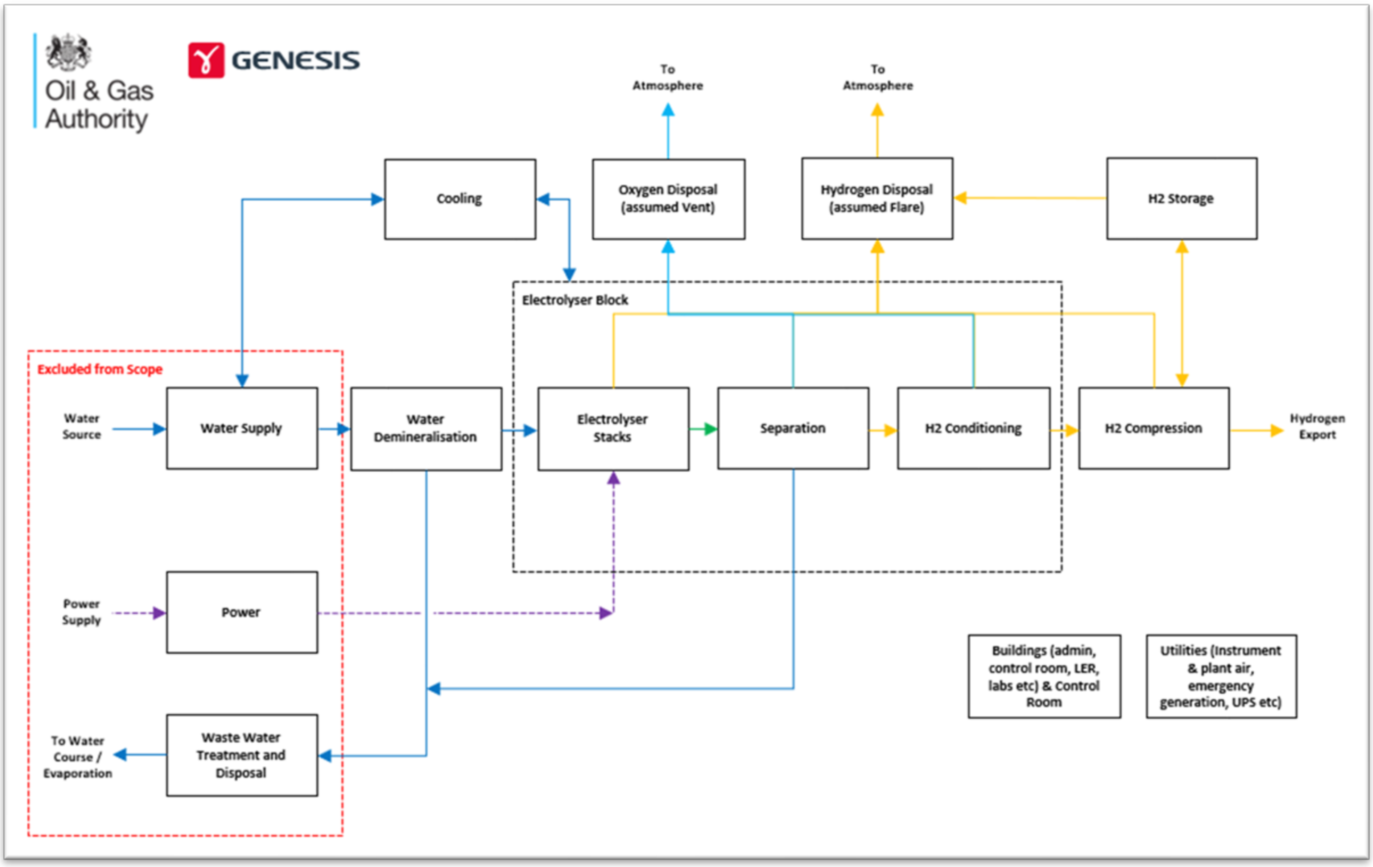


Figure 3.4 – Electrolytic Facility Flow Diagram & Battery Limits

The scoping basis of design includes the following assumptions:

- Onshore plant
- Hydrogen export at 80 barg for industry use and pipeline blending (only buffer storage for fluctuation management)
- Oxygen is vented
- Power source (offshore wind with grid connection) and water source supplied at boundary fence
- Facility constructed in 200MW packages
- Design life of 20 years with facility availability of 95%
- Safety design requires review as part of future work, an emergency flare is assumed at this stage

3.4.2 Scoping Definition

The table below presents the feedstock and production rates for the 2.1 GW facility.

PARAMETER	2.1 GW PLANT	2.1 GW PLANT
Water Feedstock	378,000 kg/h	380 m^3/h
H2 Production	36,000 kg/hr	2.1 GW
O2 Production	288,000 kg/hr	-

Table 3.7 – Facility Feedstock & Production Rates

Hydrogen production is based on stack efficiency of 75% (typical for current alkaline technology) and an overall of 67.5% efficiency (minus electrical losses and expected AC loads), corresponding to rate of 58.37 kWh/kgH2.

The power source for the 2.1 GW green hydrogen plant is assumed to be from offshore wind with grid connection; there would be an input from both sources, with a reduced import from the grid when wind speeds are high. Further future work is required to consider optimization of installed wind farm capacity, power intermittency issues and grid supplied power requirements; this should include storage and facility turndown and black start scenarios if considering a wind power source only.

The design chosen for the scoping definition is a standard 20MW alkaline electrolyser module which contains the following equipment:

- 4 x 5MW transformers
- 4 x 5MW rectifiers
- 4 x 5MW electrolysers
- 1 x separation package (including liquid/gas separators, pump, heat exchangers, etc), sized for a 20MW of electrolysers

The table below indicates the key equipment estimated electrical loads for the 2.1 GW plant.

ITEM	Quantity	Rating	Total Load (MW)
1st & 2nd Stg Compressor & Coolers	4	33%	33
Electrolyser Coolers	6 5	2 %	7.3
Chilled Water & Dehyd. Regen Air Coolers	1 1	11%	1.1
Dehydration Heater	1	100%	3.2
Alkaline Electrolysers	420	0.2%	2,10 0
Instrument Air & Nitrogen Packages	2	100%	0.7
Drains Pumps (Hazardous & Nonhazardous)	4	100%	<1
Demin System	1	100%	2.0
Fire Water Pumps	4	100%	<1
Buildings: Admin, Gate House, Electrolyser HVAC, control room, workshop	-	-	~43
Other minor pumps and axillaries	-	-	<1
		Total	**~2190 MW**

Table 3.8 – Electrical Load List

Details of the major equipment packages resulting from the scoping definition work are summarised in the table over.

System	Equipment Details	Approx. Area Required (m^2)
Compression & Cooling	- 2 stages compression, each stage includes scrubber, compressor, air cooler - 3x33% assumed - ~30 MW total compression duty	850m^2
Electrolyser Air Coolers	65 x Electrolyser Air coolers 10 x Chilled Water Coolers 1 dehydration Regen Cooler	11,000 m^2

Electrolysers & BoP Enclosed in Electrolyser Buildings (with HVAC)	Electrolysers, tanks and pumps, Buffer vessels, rectifiers, separation skids, transformers, Hydrogen purification	$48m^2/MW$ = $101{,}000m^2$
Flare & Vent	Flare, KO drum, pump	75-100m sterile radius assumed
Metering	Required for hydrogen export 2x50% assumed	$100m^2$
Emergency Diesel Generator & Storage	Generator & Diesel storage for life support services	$15m^2$
Power distribution in Substation / LER Building/s	400 kV Outdoor Switch yard, 400/33kV Distribution Transformers, 33/11kV Distribution Transformers, 11/ 0.4kV Distribution Transformers, 400 kV GIS SWGR, 33kV and 11kV Switchgear, Utilities LV Switchboards/ MCCs, Emergency MCC, Power Factor Correction, UPS systems and distribution boards	Estimated t hat substation buildings will require a total area of circa $5000m^2$ It is recommended Multiple substation buildings are used (2 or 3 depending upon layout) to optimize LV distribution
Outdoor Switchyard	Transmission, line end disconnectors, breakers, isolators, HV instruments and transmission related VAR compensation	Assumed c. 100m x 85m
Instrument Air & Nitrogen Packages	Instrument & Plant Air, Inert Gas Generation Package	$70m^2$
Drains	Closed drains vessel & pump Hazardous drains & pump	$7m^2$
Fire Protection	Pumps & water storage	$1200m^2$
Demin Package & Storage	RO unit, Demin unit, storage tanks & pumps	$3000m^2$
Buildings	Control room Workshop Admin Gate House	$500m^2$ $1000m^2$ $4000m^2$ $200m^2$

Table 3.9 – Equipment Packages and Estimated Dimensions

3.4.3 Layouts

Detailed plot plans have not been developed at this stage. The next phase of work for the BEH should consider preparation of site layouts based on more detailed assessments: allowing for typical safety distances, and layout principles for construction and plant operational requirements. Ignited hydrogen release consequence analysis assessments should also be undertaken in future project phases.

To provide context for this scoping assessment, the figure below is based on a 20MW single train where 4 x 5MW electrolysers feed into a single separation train. These 20 MW trains are then replicated into 200 MW "arrays" to make the required overall capacity. The auxiliary equipment is common for the plant.

The layout below was designed with the following criteria:

- Transformers & Rectifiers are usually located outside.

- The electrolysers are typically located in a building with natural or, if required, forced ventilation (which is defined by ATEX code requirements and operating pressure of electrolysers etc).
- The distance between the transformer, rectifier and electrolyser should be minimised to reduce electrical losses but within limits allowed by hydrogen equipment safety distances.
- Minimise footprint as much as practical.

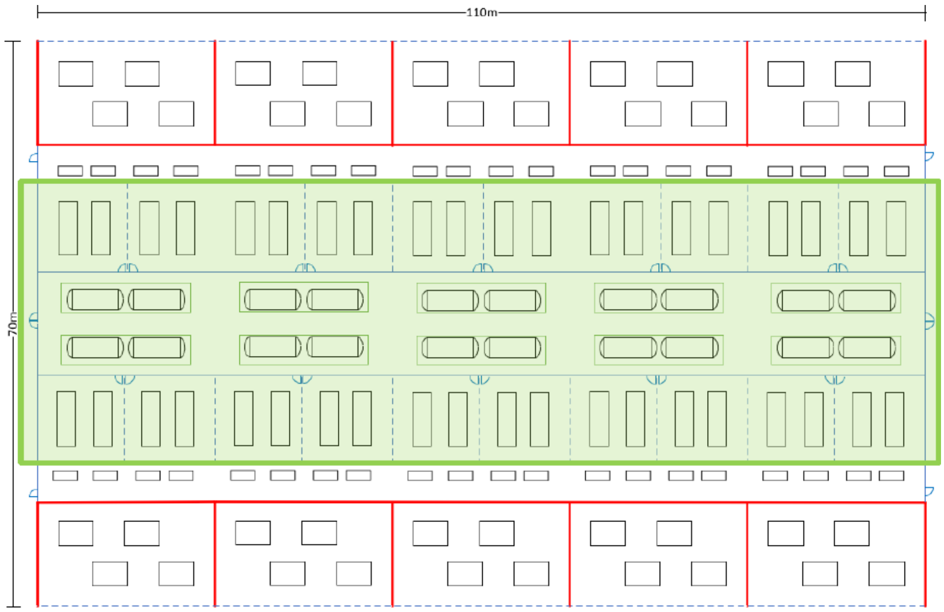


Figure 3.5 – Layout for 200MW Array

The indicative electrolyser layout (electrolysers and separators highlighted in green) above can vary depending on many factors including electrolyser vendor design, pipeline access, power source access, prevailing winds, plot space available, proximity to existing infrastructure including underground pipelines etc.

Key principles & factors to be considered when optimising the layout include:

- Existing site constraints such as underground pipelines & cables, overhead power lines, fences, roads, other assets and public walking routes etc
- Grouping of equipment sources of similar hazards together
- Separation distance from occupied areas should increase with increasing equipment hazard levels
- Prevailing wind - recognising that hydrogen is a light gas that can be expected to disperse much more rapidly utilising the prevailing wind direction
- Location of the hydrogen flare and oxygen vents relative to prevailing wind and other hazardous areas
- Hazardous process units and process conditions (pressures) to be located furthest from the areas where people (and vehicles) will be present and where emergency services may be required to access/ egress site
- High pressure hydrogen operations (e.g. compression) and its associated pipeline corridor to be located furthest from locations where people are most likely to be present (i.e. occupied buildings)
- Lower pressure hydrogen sources (e.g. electrolysers) located in a corridor between the higher pressure hydrogen sources and the area where no hydrogen hazard exists
- Electrical hazard sources (apart from those directly associated with electrolysis operations)

separated from hydrogen process operations

- Vents and safety relief equipment shall be routed to a safe location, where they do not generate a hazard to personnel, electrical sources and other ignition sources, neighbouring structures (e.g. building openings or overhangs)
- The layout shall also ensure processing efficiency, and shall, as far as reasonably practicable, minimise pipe runs transporting hazardous fluids.

3.4.4 Turndown and Phasing

There are a number of considerations related to turn down and management of hydrogen production, these include:

- Differentiation between overall facility and individual stack turndown
- Operability of deoxygenation equipment and dehydration media at low flow rates
- Compressor configuration and individual compressor turndown
- Pressure cycles and the impact on electrolyser design life

At present suppliers are delivering electrolyser plants in 100MW-250MW arrays. Whist this is expected to improve in the future issues such as stack replacement, installation and turndown. The current assumption for the BEH is that a 2.1GW facility would be phased with the installation of 200MW arrays over a 4-6 months period. Stack replacement is assumed to be required around year 10.

3.4.5 Risks and Opportunities

The key risks identified for the electrolytic production facility during the scoping design include:

- Power source (stability/intermittency and grid capacity)
- Electrolyser costs and supply
- Market uncertainty
- Safety design
- Regulatory approvals

There are however opportunities that may address some of these risks and others, these include:

- Technology innovation (electrolyser sizing, cost reductions etc)
- Layout optimisation
- Integrated development schemes with CCS enabled hydrogen production (construction, utilities etc)
- Targeted markets for optimising development and facilities design

Recommendations for further work to address some of the risks identified and optimise the design basis are provided in the Genesis report.

3.5 Water Supply and Desalination Requirements

A study was carried out by Goal7 on behalf of Neptune Energy for the BEH. An outline technology review was undertaken for seawater desalination to provide the water feedstock for electrolytic and CCS enabled hydrogen production, for BEH core and build out scenarios.

An initial screening (based on suitability for site, scale, technology readiness level (TRL) and water quality required for electrolysis) identified four suitable technologies, and following a more detailed review including cost, footprint and water quality, SWRO was carried forward as the base case.

Discussions were held with Anglian Water to establish if a local potable water supply could be provided to negate the need for desalination. It was quickly established that this would not be possible due to supply constraints and licensing restrictions, in fact Anglian Water was considering desalination as one option to mitigate supply shortages and a co-development scenario should be pursued further to address the demand for both the BEH and local domestic and agricultural uses.

The study developed a base case for the BEH development scenarios to satisfy capacity and product quality requirements together with consideration of facility sizing, costs and site location (including inlet and outlet pipelines routing); a summary of the results is presented in Table 3.10.

Parameters	Core Project	Build out 2030	Build out 2040	Build out 2050
H2 Capacity	1 x 355MW CCE enabled	3 x 355 MW CCS enabled	3 x 355 MW CCS enabled + 2 x 1.8 GW upscaled SMR/ATR + 1 x 2.1 GW Electrolyser	2 x 1.8 GW upscaled CCS enabled + 3 x 2.1 GW Electrolyser plants (NB 3 x 355MW CCS enabled retired)
Total	355MW CCS enabled	1GW CCS enabled	4.7 GW CCS enabled 2.1 GW Electrolyser	3.6GW CCS enabled 6.3GW Electrolyser
Maximum supply from H2 per year	CCS enabled: 3TWh – 100% of demand	CCS enabled: 9TWh – 100% of demand Electrolytic: 0 TWh – 0% of demand	CCS enabled: 39TWh – 54% of demand Electrolytic: 18 TWh – 46% of demand	CCS enabled: 30 TWh – 33% of demand Electrolytic: 54 TWh – 80% of demand
H2O input required (m^3/hr)	45	135	1,527	3,264
Seawater intake (m^3/hr)	126	378	4,277	9,140
Electricity requirement (kW) (1)	198	594	6,720	14,363
Capacity (m^3/day)	1,080	3,240	36,656	78,344
Estimated CAPEX ($m)	2.5	7.5	84	180
Estimated OPEX ($m/yr)	0.15	0.45	5	11
Typical Plant footprint (m^2)	1,233	2,124	19,729	27,066

Water Storage (m^3) (2)	1,080	3,240	36,656	78,344
Water Storage Footprint (m^2) (2)	150	300	2,000	4,000

Table 3.10 – Desalination Plant Sizing

It is assumed that, particularly given the significant area required for the facilities for later build-out scenarios, the water processing and treatment facilities are located adjacent to the existing Eni site where the production processing facilities have been assumed to be located. Other considerations will influence final site locations such as:

- Proximity from saline water source and discharge points (c. 1km);
- Proximity from delivery points of desalinated water and electrical supply (c. 8km);
- Environmental;
- Topography;
- Accessibility;
- Etc.

An estimate of the dimensional requirements for the various development scenarios is presented in Table 3.11 below.

Case	Footprint (m^2)	Rough Dimensions (m)
Core	1,200	44 x 28
Build out (2030)	2,100	57 x 36
Build out (2040)	19,700	176 x 112
Build out (2050)	27,000	206 x 131

Table 3.11 – Desalination Plant Dimensions

The following main conclusions and observations result from the work completed to date:

Desalinated water is required as freshwater is becoming increasingly scarce in this region;

Site proximity to seawater feed stock is very good;

Suitable desalination technology exists, an optimised assessment should be undertaken later;

Synergies with the future plans of Anglian Water should be explored, benefits for the security/supply of local water and therefore the residents may be possible from a co-ordinated approach.

3.6 Production Technology Review

3.6.1 CCS Enabled Hydrogen

Progressive Energy Ltd has provided a review of CCS-enabled hydrogen production technology and concluded the most suitable technologies for the commercial scale production of hydrogen from natural gas feedstocks in this context are the Gas Heated Reformer + Autothermal Reformer (GHR+ATR), and the Non-Catalytic Partial Oxidation (POX) processes. Both technologies are deployed or planned to be deployed in various industrial clusters and provide high thermal efficiency in the conversion of methane to hydrogen, and facilitate the near complete (95%+) capture of CO_2 generated as a by-product for permanent offshore geological storage.

The technical readiness level (TRL) was subjectively assessed for each of the main steps/operations in producing CCS-enabled hydrogen from methane, the table below provides a summary of the assessment for each of the operations.

Process	TRL	Comments
Air Compression/ O2 Production	Mature	TRL for process using ceramic membranes considered Low
Feed Gas Pre-treatment	Mature	Mature technologies exist for treatment of sulphur, mercury and chlorides
Re-forming/ Hydrogen Production	Generally mature but new technology evolving at a Low TRL.	New technologies generally at pilot scale evolution but in time could reduce LCOH and increase CC rates.
CO Shift	Mature	Proven technology
CO2 Capture	Mature	New as yet unproven at scale technologies evolving
CO2 Conditioning & Compression	Mature	
Hydrogen Conditioning & Compression	Mature	

Table 3.12 – TRL Assessment for Production Systems/Facilities

The appropriate technologies for deployment at the Bacton Energy Hub are considered to be the coupled GHR + ATR or Non-Catalytic Partial Oxidation as these technologies are mature, demonstrated and well optimised at the scale required in the study. However, the final selection will also need to consider LCOH and environmental considerations and other participant's drivers.

3.6.2 Electrolytic (Green) Hydrogen

Genesis has provided a review of electrolytic hydrogen production technology focusing on the key elements relevant for the BEH development scenarios as follows:

- Electrolyser technology;
- Hydrogen compression;
- Water demineralisation;
- Hydrogen storage.

3.6.2.1 Electrolyser Technology

There are three main types of electrolysers based on the electrolyte material involved:

- Alkaline Water Exchange (AWE)
- Polymer electrolyte membrane (PEM)
- Solid-oxide electrolysers cell (SOEC)

In addition, there are the less mature technologies including:

- Anion exchange membrane (AEM)
- Electrochemical Thermally Activated Chemical (E-TAC)
- Supercritical.

Figure 3.6 – Electrolyser Type Assemblies

The criteria for selection of technology or supplier have been identified and selected key criteria are presented in the table below.

Selection Criteria	Description
TRL	Technical Readiness Level and ability to be reliably deployed
Efficiency	Power to hydrogen efficiency, critical to the business case for large scale projects
Turndown	Ability to operate at low load and manage the intermittency of renewable power sources
Start-up & Ramp-up/down	Time taken to bring electrolyser stacks back on line and resistance to cyclical operations which may result from a varying power source
Hydrogen production pressure	Production pressure and need for costly compression equipment

Feedwater & product purity	Tolerance of feedwater impurities typically extends equipment life and reduces cost. Product purification steps impact costs/efficiency.
Stack Design	Larger and fewer stacks are generally more cost effective and a longer operational life will equally reduce intervention costs.

Table 3.13 – Electrolyser Selection Criteria

A comparison of the three main types of electrolysers and current suppliers is presented in the table below.

	Alkaline	PEM	SOEC
Manufacturers	Cockerill, McPhy, Hydrogen Pro, Thyssenkrupp, Sunfire, NEL Hydrogen, GHS, Cummins	H-Tec, NEL Hydrogen, Cummins, H-Tec (MAN), Siemens, ITM, Ohmium, Plug Power, Elogen	Sunfire, Haldor Topsoe, Bloom
Efficiency	70-75% (Typical)	70-75% (Typical), 75% (Siemens)	90% (Haldor), 90%+ (Bloom)
TRL	9	9	7
Start Time (Warm/Cold)	5 min / 60 min (Typical)	30s / 5min (Plug)	6min / 15hr (Bloom)
Operational Flexibility	40-100% (Cummins)	10-100% (Siemens) 5-125% (Cummins)	10-100% (H-T)
Product Pressure	30barg (Cockerill) 30barg (McPhy) Atm (Thyssenkrupp, Nel)	20-30barg (ITM) 40barg (Plug)	Atm (Bloom) 2barg (H-T)
Lifetime / Stack Replacement	10yr (Sunfire)	10yr (Siemens)	5yr (Bloom)
Purity	99.8 (Cockerill) 99.99 (after drying)	99.999 (ITM), 99.999 (Plug)	99.99 (after drying)
Capital Cost ($/kW)	Moderate	High	High
Feedwater Quality Requirement	Flexible	High	High
Size / Weight	$45m^2$/MW	25-$30m^2$/MW	~$45m^2$/MW

Table 3.14 – Electrolyser Technology Comparison

The electrolyser market is moving quickly with two currently dominant technologies: Alkaline and PEM. These technologies offer different benefits with PEM more expensive but offering more operational flexibility (very important if power source is not stable) and higher product quality (without conditioning). At present both technologies have a significant global manufacturing capability with plans for a number of “giga-factories” for both technologies. It is clear that at present, for projects looking for sanction in the next 2-3 years the choice will be between flexibility and efficiency. Many players are making claims of increases in efficiency within the decade, particularly PEM.

SOEC is likely to offer the only major disruption to this duopoly in the near future with the offer of significant further efficiency gains at the cost of reduced flexibility with some manufacturers claiming 10-30% increase in efficiency compared to PEM/Alkaline systems already on the market. SOEC could start to displace Alkaline systems providing relatively inflexible “base load” production, particularly where other derivatives of hydrogen are produced such as ammonia and synthetic fuels as SOEC works well with other industrial processes where waste heat is available.

Towards the end of the decade, and subject to overcoming challenges with cell durability, AEM has the potential to displace both PEM and Alkaline as it is claimed to offer the operational flexibility of PEM, cheaper materials than PEM and the efficiency of Alkaline. It also has the side benefit of much higher tolerance to feedwater specification with some manufacturers claiming that even brines could be used as feedwater. Current commercialisation plans by the AEM suppliers talk about delivering at commercial scale by mid-2020s however full-scale manufacturing capability at the level required to service multiple GW scale projects would likely not be until the early 2030s. This technology could be a game changer for developments with water quality challenges.

It should be noted that other factors require consideration for the BEH development plan, for example a robust hydrogen storage concept for BEH could negate the need for electrolyser flexibility.

3.6.2.2 Hydrogen Compression

Following hydrogen production through electrolysis, and depending on the electrolyser technology in use, hydrogen needs to be compressed for either supply or storage, depending on the end user application. The majority of current technologies currently produce hydrogen at around 30barg and the compression requirements could be generally as follows:

- Highly compressed for mobility (fuel cell) use: typically 300-700barg
- Moderately compressed for delivery by pipeline: typically 60-100barg
- For hydrogen compression there are a number of different factors which have to be considered:
- Flow rates & compression ratios
- Load variations and turndown
- Power and cooling requirements
- Molecular weight of hydrogen and acceleration difficulties
- Diffusivity of hydrogen

Currently it is envisaged that centrifugal compressor designs will be market leaders for hydrogen applications into the 2030s. Should pipeline delivery system capacities become sufficiently large then it is possible that axial compressors may provide advantages.

3.6.2.3 Water Demineralisation

Electrolysers require a supply of demineralised water for electrolysis (typically 10.5 kg/ Kg hydrogen produced). Water quality is a central factor to ensure long-life operation of an electrolyser, for PEM electrolysers poor water quality is one of the main reasons for stack failure

The dominant technology for the production of demineralised water is Reverse Osmosis (RO). These packages are considered to be technologically mature due to their application in a range of other industrial sectors including power generation (for boiler feed water), waste water treatment and generation of high specification feedwater.

3.6.2.4 Hydrogen Storage

Due to its low density, any significant hydrogen storage will require very large storage volumes that could comprise a significant proportion of the total overall plant costs. Storage may be required to provide a buffer for supply, owing either to the intermittency of the hydrogen generation from renewables or to variations in demand.

The key technologies for hydrogen storage are considered to be:

- Cylinders
- Pressure vessels
- Underground pipelines
- Line pack
- Underground caverns
- Liquid storage

A summary overview of the potential storage options for hydrogen is presented in the table below.

Storage Type	Typical Pressure (barg)	Typical Volume (m^3)	Hydrogen Stored (kg)
Cylinder	350 - 750	1 - 10	10 - 50
Pressure Vessels	Up to 199 / Up to 799 (Note 2)	10- 70	1,000
Underground Pipes	40 to 85	800 – 3,000	10,000
Bored Shafts	199 - 299	1,500 -15,000	50 – 500
Caverns (Note 3)	50 - 200	5,000 – 500,000	1,000 – 50,000
Liquefied[1]	10 - 30	3 – 100	200 – 7,000

Notes:

1. There is a significant energy penalty associated with hydrogen liquefaction.
2. Up to 200 bar for steel cylinders and up to 800 bar for composite tanks.
3. Storage is based on the geological structure of the cavern, values presented are typical.
4. Underground pipelines can be stored in pressures up to 140 bar in specific cases.

Table 3.15 – Hydrogen storage options

3.7 CCS Feasibility

A high-level assessment of the potential CCS storage options was undertaken by Neptune Energy and Oilfield Production Consultants (OPC), this also considered the potential pipeline transportation options through existing infrastructure. The assessment was derived from public domain data and criteria included the following:

- Timing re: CoP dates compatible with BEH operational in 2030
- Sufficient storage capacity until 2050
- Limited leak paths (well count)
- Existing pipeline infrastructure

A summary of the Bacton pipeline data with a simplified 'traffic light' assessment for BEH applicability is presented in the table below.

Pipeline	Operator	Key fields	Traffic Light	Likelihood of availability in 2030	Connection to Store	Pipeline Condition	Pipeline size (")	Pipeline Age in 2030	MAOP (barg)
SEAN P TO BACTON TERMINAL TRUNKLINE	ONE-DYAS	**Sean**		CoP ~ 2025	Yes / Maybe		NA	NA	NA
Leman BT to Bacton A2	Perenco Oil and Gas	**Leman**		Currently producing	Yes / Maybe		30	60	99.3
Leman 49/27 AP to Bacton A1	Perenco Oil and Gas	**Leman**		Currently producing	Yes / Maybe		30	62	93.1
Lancelot to Bacton	Perenco Oil and Gas			Currently producing	Yes / Maybe		20	38	103.5
Indefatigable 49/23 AT to 49/27 BT	Perenco Oil and Gas	**Indefatigable**		Currently producing	Yes / Maybe		30	59	110
Clipper PT to Bacton	Shell	**Clipper South, Galleon**		Currently producing	Yes / Maybe		24	40	112
Leman AP to Bacton	Shell	**Leman**		Currently producing	Yes / Maybe		30	63	99.3
Bacton to Clipper PT	Shell	Clipper South, Galleon		Currently producing	Yes / Maybe		3	36	150
Bacton to Leman AP	Shell	Leman		Currently producing	Yes / Maybe		4	63	45
LEMAN 49/26-BT TO BACTON	Shell	Leman		Currently producing	Yes / Maybe	Poor	30	57	Mothballed
Trent tie-in to Bacton	Perenco Oil and Gas	Cygnus		Unlikely CoP to mid 2030s	No		24	46	131
BACTON TO THAMES	IOG PLC	Elgood		Unlikely CoP to mid 2030s	No		24	44	129
HEWETT SOUTHERN EXPORT A-LINE TO BACTON	ENI UK LIMITED	Hewett		CoP now	Yes / Maybe	Poor	30" external	62	N/A following pipeline failure*
HEWETT NORTHERN EXPORT B-LINE TO BACTON	ENI UK LIMITED	Hewett		CoP now	Yes / Maybe	Poor	30" external	57	26.89**
SHEARWATER TO BACTON (SEAL)	Shell	Elgin Franklin		Unlikely CoP to 2040s	No		34	31	153

Table 3.16 – Bacton Pipeline Data

A summary of the estimated CO2 storage requirements for the respective development scenarios is presented in the table below.

2030 - 2050 Capacity Requirments (MT CO_2)						
Scenario	Core			Build Out		
Case	Low	Mid	High	Low	Mid	High
Storage Capacity (Cum. 2050)	21	**42**	63	63	**84**	105
Injection Rate (MT/yr)	1	2	3	3	4	5
Wells Required	1	1	1	1	2	2

Table 3.17 – Estimated CO2 Storage Volumes

Over 20 no. potential gas storage fields were considered and screened with the existing dataset. The interim conclusions are that there are a number of potential CCS fields including Hewett, Leman and Indefatigable but further work is required to confirm their technical and commercial viability for CCS applications. Concerns to be addressed include compartmentalisation and adequate sealing where a high number of wells have been drilled and the costs/schedule associated with developing a viable CCS field. Existing pipeline integrity and the need for new pipeline(s) and injection facilities requires a detailed review for the CCS duty.

It is worth noting that the recent CCS licensing round has had a reasonably high number of applications and it is expected that this has included fields in the Southern North Sea with potential to service the BEH.

4 Costs and Economics

IO Consulting has prepared AACEi Class 5 cost estimates for the respective development scenarios with inputs provided by representatives of the SIG work streams. The cost estimates have been used to generate economics analyses and estimates for the levelized cost of hydrogen (LCOH). Table 4.1 presents the capital cost summary:

Capital cost (GBP mm real)	2030 core	2030 build-out	2040 build-out	2050 build-out
National grid upgrades	49	100	150	-
Desalination plant	2	7	73	99
CCS enabled hydrogen plant	350	998	2,757	35
Electrolytic hydrogen plant	-	-	1,283	2,356
NTS modifications	5	10	20	20
CO_2 export pipelines	5	5	88	-
CO_2 export power cable	-	-	28	-
CO_2 sequestration (facility)	50	50	136	-
CO_2 sequestration (wells)	60	120	300	-
Land acquisition	-	4	18	33
Capital cost (incremental)	**521**	**1,294**	**4,853**	**2,543**
Capital cost (cumulative)1	**521**	**1,294**	**6,147**	**8,690**
CCS enabled hydrogen plant (% total)	67%	77%	57%	1%
Electrolytic hydrogen plant (% total)	-	-	26%	93%

Note 1 The 2040 and 2050 build-out cumulative costs are incremental to the 2030 build-out cost

Table 4.1– Capital Cost Summary

The annual operating expenditure estimate is summarised in Table 4.2:

Operating cost (GBP mm p.a. real)	2030 core	2030 build-out	2040 build-out	2050 build out
National grid upgrades	1.5	3.0	4.5	-
Desalination plant	0.1	0.4	4.2	9.2
CCS enabled hydrogen plant	10.5	29.9	82.7	-
Electrolytic hydrogen plant	-	-	25.7	47.1
NTS modifications	0.2	0.4	0.8	0.8
CO_2 export pipelines	1.8	1.8	1.8	-
CO_2 export power cable	-	-	0.9	-
CO_2 sequestration (facility)	2.0	2.0	5.4	-
CO_2 sequestration (wells)	2.6	2.6	5.4	-
Operating cost (incremental)	**18.6**	**40.1**	**131.3**	**57.1**
Operating cost (cumulative)1	**18.6**	**40.1**	**171.4**	**228.4**

1 The 2040 and 2050 build-out cumulative costs are incremental to the 2030 build-out cost

Table 4.2– Operating Expenditure Summary pa

In an effort to provide consistency and some means of comparative assessment, the LCOH analyses uses cost assumptions, such as electricity and gas pricing, from the BEIS 2021 hydrogen production cost report. Figure 4.1 presents a summary of the LCOH analyses for the different development scenarios.

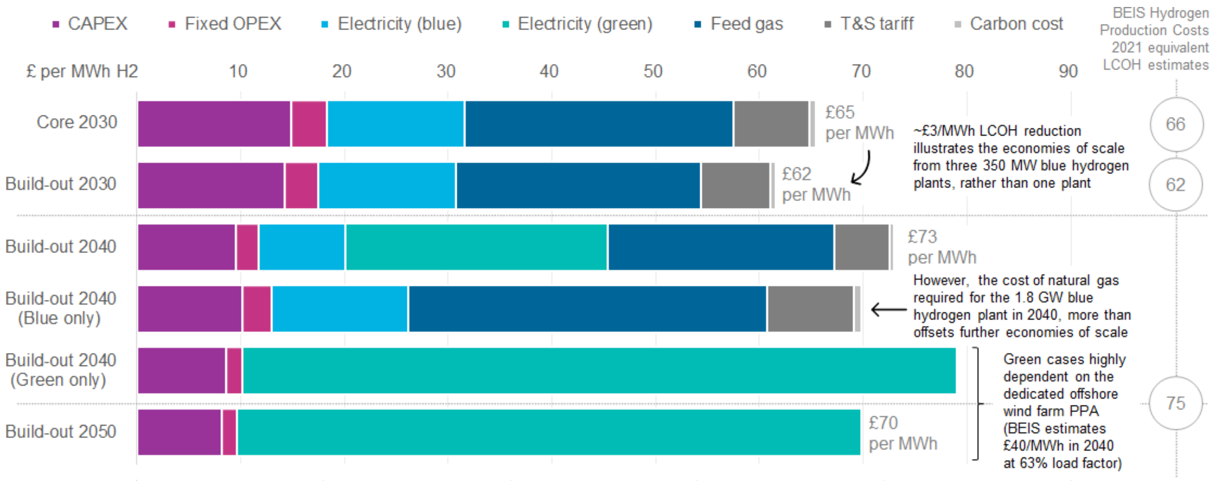


Figure 4.1– LCOH Summary

The feasibility level analyses highlight the sensitivity of the CCS enabled hydrogen 2040 build-out case to feed gas supply volumes and pricing. Regulatory and Governmental support is a likely requirement to address this issue and the indicative absence of economies of scale.

The analyses also highlight the impact of current assumptions relating to energy supply pricing for the electrolytic hydrogen cases, further sensitivity analyses would be beneficial in addressing some of the key uncertainties. Alternative operating modes, sources of power and advances in electrolyser and energy storage technologies could significantly alter the LCOH for electrolytic hydrogen.

Figure 4.2 illustrates the impact of key uncertainties on the central case levelised cost estimates (shown for reference on the vertical axis) for the 2030 core project and the 2050 build-out scenario.

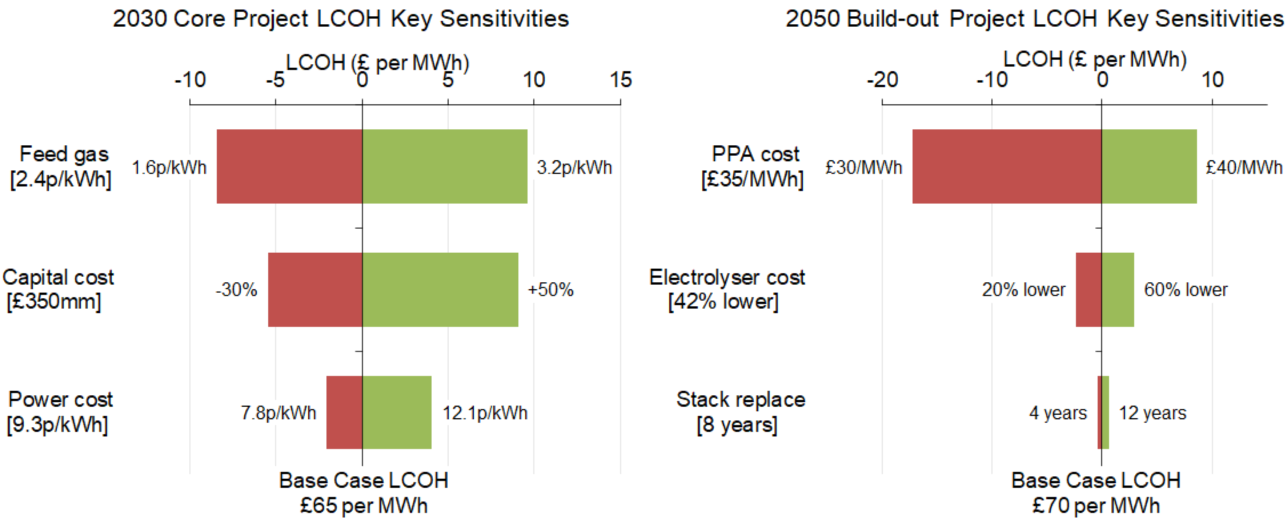


Figure 4.2 – LCOH Sensitivities

The 2030 core project, which is exclusively CCS Enabled hydrogen production, central case LCOH of £65/MWh is most sensitive to the feed gas price and capital cost estimate. The natural gas price high case increases the LCOH by +£10/MWh and a 50% capital cost growth increases the LCOH by +£9/MWh. The high gas grid electricity prices increase the LCOH by +£4/MWh.

The 2050 build-out, which is exclusively electrolytic hydrogen production, central case LCOH of £65/MWh is most sensitive to the dedicated offshore wind electricity price. A £5/MWh lower PPA price reduces the LCOH by -£17/MWh, highlighting the high uncertainty of future electrolytic hydrogen cost.

5 Risks Assessment

A simplified risk assessment is presented in the table below based on the primary findings from the BEH study Supply SIG terms of reference. This assessment is not comprehensive and provides only a subjective 'traffic light' assessment at this stage; it may not fully reflect current progress and finding of other work streams and should be developed further with a quantitative assessment during the next phase of work for the BEH. The majority of post-mitigation risks are indicated as amber, this is considered a likely outcome given the feasibility level of the work at this stage.

Risk/Description	Risk Pre-Mitigation	**Possible Mitigation**	Risk Post-Mitigation
CCS Enabled Hydrocarbon Production			
Lack of domestic supply		Further review of reserves estimates. Option to use imported gas via Interconnectors. Earlier electrolytic hydrogen	
High gas price		Government (CFD) support likely required. Consider dedicated supply option.	
Facilities footprint exceeds available space		Further work required particularly for build-out phases. Commence consents/planning process early.	
Electrolytic Hydrogen Production			
TRL for production at scale is too late for BEH		Current pace of technical development is focused on production at scale	
Facilities footprint exceeds available space		Further work required particularly for build-out phases. Commence consents/planning process early. Assess offshore option.	
OWF power supply intermittent, back up required		CCS Enabled hydrogen, hydrogen storage & grid connected power supply offer potential solutions	
Construction & Schedule			
Complex construction adjacent to operational facilities (SIMOPs)		Similar construction projects at COMAH sites have been successfully executed before	
Phasing of CCS Enabled & electrolytic hydrogen mismatched with demand requirements.		Demand requires continual assessment up to FID and beyond. Early contractual commitments.	
Supply chain constraints particularly with electrolytic hydrogen supply chain causes delays		Early engagement/assessments & detailed planning. Possible early commitments with key suppliers.	

CCS			
Lack of suitable sites delays CCS Enabled hydrogen development		CCS progress to be monitored closely for alignment with BEH. Recent licensing round appears encouraging	
Cost to access CCS infrastructure is too high		SNS offers good CCS opportunity. CCS is a Gvt/industry commitment & will require an 'acceptable' commercial model. BEH could access a larger regional CCS scheme.	
Power Supply			
Inadequate local grid connection capacity for BEH facilities		Supply for initial CCS enabled hydrogen requirements appears possible. Evaluate alternatives (grid upgrade, renewables etc)	
Desalination Facilities			
Brine discharge & dispersal		Use of existing pipelines for distant offshore disposal, blending, etc	
Facilities footprint & location		Further work required particularly for build-out phases. Commence consents/planning process early.	
General			
Project economics are a challenge		Detailed modelling & facilities optimisation. Gvt incentives. Macro pressure to make energy transition successful, Gvy CfD arrtangements for the hydrogen economy	
Insufficient demand for hydrogen		Detailed demand modelling. Focus on key consumers ie power stations. Gvt incentivisation and blending into the grid	
Delays in regulatory processes adversely impacts schedule		Early applications & stakeholder engagement. Energy transition a national priority	
Public perception/relations issues and resistance to BEH especially blue hydrogen development		Stakeholder engagement & PR process. CCS Enabled hydrogen an enabler for energy transition	
Possibility of CCS & BEH competing for same land/space		Future co-ordinated & detailed assessment with Gvt support following recent CCS licensing applications	

6 Conclusions and Recommendations

The initial conclusions and observations resulting from the respective work streams within the Supply SIG are summarised below. Although the work undertaken to date is considered as at a feasibility level of definition, it nonetheless supports the original premise that Bacton is well positioned to become a significant hydrogen production and distribution facility together with associated carbon dioxide and potential hydrogen storage capabilities.

Gas supply for the CCS enabled hydrogen option requires further more detailed review. A base case development with a 355MW CCS enabled plant would require approximately 30mmscfd of feed gas. For the build-out case sufficient gas supply is available until around 2040 when imported gas or LNG would be required with an associated impact on CCS enabled hydrogen LCOH under current assumptions. The commercial model for prioritising gas for hydrogen production would also need further review. It is recommended that the next phase of study work for the BEH should include optimisation work where alternative development cases assessing differing plant capacities and feed gas volumes with other demand scenarios is performed to firm up the final plant configuration.

Energy supply pricing for the electrolytic hydrogen options also requires further review and sensitivity modelling; adopting alternative assumptions to reflect future techno-commercial advancements could have a significant positive effect on LCOH.

Technical readiness levels for both CCS enabled hydrogen and electrolytic hydrogen production facilities are considered to be at an adequate level of maturity to support the BEH current schedule assumptions. It is anticipated that further advancements will be realised, particularly with electrolyser technology which will provide economies of scale and pricing benefits. Supply chain engagement is recommended to obtain further information and forecast data for project critical resource equipment and activities.

Dedicated water production and discharge facilities should be considered as a base case requirement for BEH development scenarios. Anglian Water has confirmed there are potable water supply constraints particularly for the volumes being considered for the BEH. Furthermore, there may be synergies in oversizing the facilities for BEH and providing a supply for domestic consumers; such an approach may provide cost benefits and assist planning issues where applicable.

Layout requirements, in particular for the Build-out phases will require significant additional land acquisition which will result in some planning and permitting challenges. It appears that the core project can be accommodated largely within the current Bacton area but a more detailed review of the construction methodology regarding laydown areas, personnel numbers, logistics and simultaneous plant operations is needed to confirm this. The candidate CCS scheme may also need consideration in defining final layout requirements.

Electrolytic hydrogen production which is likely to be supplied by offshore wind generated electrical power is central to the energy transition aspirations. As such, methods of addressing the intermittency of offshore wind power require further review. This could include extending blue hydrogen production beyond the current assumption for its CoP date. Hydrogen storage would be fundamental in this review and the existing Bacton pipeline infrastructure would provide significant storage volumes if suitability were confirmed.

It is considered that the next phase of work for the BEH should include the following as a minimum:

- Additional CCS enabled hydrogen/ electrolytic hydrogen production scenarios with different capacity assumptions and timings;
- Supply chain engagement to better define critical equipment and activity expectations and schedules;
- Detailed schedule work to identify critical path activities for delivering the BEH, this would include the planning and consents timelines and offshore wind deliverability;
- An assessment of the provision of offshore wind power for BEH and how the existing consents process impacts this, new wind farm with private wire connection or extension to an existing wind farm etc;
- A review of potential CCS schemes relevant to the Bacton region from the recent licensing round;
- Potential solution for offshore wind farm production intermittency;
- Further economics analyses for alternative development scenarios;
- Consideration of offshore hydrogen production facilities as a potential solution for spatial and layout constraints.

Appendix 1 Development Scenario Assumptions and Key Data

		Core Project	Build-out
Demand	**Demand Base Assumption**	Supply Driven Domestic Only	Balanced supply / demand scenario Domestic Only 70% of current domestic gas demand is met with hydrogen (by 2040)
Demand	**Maximum Demand (TWh)**	7.9 TWh (2030), 58.2 TWh (2040), 90.3 TWh (2050)	7.9 TWh (2030), 58.2 TWh (2040), 90.3 TWh (2050)
Demand	**Maximum Blend %**		Assumed 20% blend in 2030 increasing to 100% hydrogen in some parts of region in 2040, all 100% hydrogen in 2050
Demand	**Phasing Description**		Assumes blending into NTS by 2030. 2030 demand dominated by blend into NTS/LDZ supply for domestic/commercial; full conversion to 100% hydrogen over time
Supply	**Supply Base Assumption (CCS Enabled, Electrolytic, CCS Enabled + Electrolytic)**	CCS enabled Only*	CCS enabled + Electrolytic
Supply	**CCS Enabled / Electrolytic Phasing Description**	1 (or 3 depending on demand at the time) x 355MW SMR/ATR Plant, no additional investment	2030: 3 x 355 MW SMR/ATR plants 2040: 3 x 355 MW SMR/ATR + 2 x 1.8 GW upscaled SMR/ATR + 1 x 2.1 GW Electroliser 2050: 2 x 1.8 GW upscaled SMR/ATR + 1 x 2.1 GW Electroliser + 2 x 2.1 GW Electroliser plants (NB 3 x 355MW SMR/ATR retired)
Supply	**Maximum Supply from CCS Enabled Hydrogen (TWH / %?)**	3 TWh – 100% of demand	9 TWh – 100% of Demand (2030), 39 TWh – 54% of demand (2040) 30 TWh – 33% of demand (2050)
Supply	**Maximum Supply from Electrolytic Hydrogen (TWH/ %?)**	Zero	0 TWh – 0% of demand (2030) 18 TWh – 46% of demand (2040) 54 TWh – 80% of demand (2050)
Supply	**CCS Enabled Hydrogen Feedstock Assumptions**	Producing and Reserves (Requires approx. 30 mmscf/d). Availability of indigenous	Producing and Reserves + Undeveloped discoveries for Hydrogen with possible import 2040 onwards. Estimated hydrocarbon feedstock: 82 mmscf/d (2030) 356 mmscfd (2040)

		supply to be confirmed by SIG	274 mmscfd (2050) NB All figures to be verified by SIG, and assessment of indigenous vs imported supply
Supply	**Electrolytic Hydrogen Feedstock Assumptions**	N/A	Redeployment of constrained wind power + connection to (green) grid (2040), Dedicated wind/solar plus connection to (green) grid (2050)
Supply	**Export Yes / No?**	No	No
Supply	**CS Yes / No?**	Yes	Yes
Supply	**Hydrogen Storage Yes / No?**	No	Yes
Infrastructure	**Land requirement**	Within existing plant boundary	CCS enabled hydrogen within existing plant boundary with potential re-use of existing plants as part of consolidate of terminals [to confirm as part of study] Expansion of plant likely required for electrolytic hydrogen [to be confirmed as part of the study]
Infrastructure	**CCS Enabled Hydrogen Base Assumptions**	Existing upstream gas pipelines available to supply natural gas to terminal over life of project. Electricity supplied from the grid for H2 generation + CO2 capture plant [to confirm no grid constraints]. Depending on technology steam / oxygen generation Desalination plant [to be confirmed]	Existing upstream gas pipelines available to supply natural gas to terminal over life of project [to be confirmed as part of study]. May require import of natural gas from Europe. Electricity supplied from the grid for H2 generation + CO2 capture plant [to confirm no grid constraints]. Depending on technology steam / oxygen generation Desalination plant [to be confirmed]
Infrastructure	**Electrolytic Hydrogen Base Assumptions**	N/A, unless local supply	Electricity supplied from green source (offshore wind). New desalination plant required. New water handling plant.
Infrastructure	**Hydrogen Evacuation Base Assumptions**	To be agreed as sensitivity on Base Case. Assume some blend of NTS + others	Current NTS (heating) – blend TBC. Transport (local) Ports Power station

Infrastructure	**CO2 Transport and Storage Assumptions**	Green field or re-use existing pipelines / storage or route to existing storage site [to be confirmed as part of study] with required injection rate of 0.8 mtpa. Assume transport of CO2 to already approved CCS (Northern Endurance) projects unlikely due to consenting issues for new onshore CO2 pipeline	New storage site and pipeline required [to be confirmed as part of study] with required injection capacity of: 2030: 2.4 mtpa 2040: 10.4 mtpa 2050: 8 mtpa
Infrastructure	**Hydrogen Storage Base Assumption**	N/A	To identify potential suitable Hydrogen storage sites (if available) – new salt caverns, existing salt caverns (e.g. Teesside) depleted hydrocarbon fields, line pack
Infrastructure	**Export Base Assumptions**	N/A	N/A
Key Assumptions /Critical Givens?		CO2 licence application Viability of H2 plant @ Bacton Supply chain capacity building Ability to blend into grid at X%	CO2 licence application Viability of H2 plant @ Bacton Supply chain capacity building Offshore wind connection electrolytic H2 plant Ability to blend into grid at X%

*Excludes (for now) the possibility of an "Early Production System" for Electrolytic Hydrogen
Facility retirement assumed after 20 years from first hydrogen

Appendix 2 Supply SIG Report References

Supply SIG Document Register

BEH Document Number	Prefix	Document type	Sequential number	Document Name	CTR No.	Revision (A,B,C, 0, 1, etc)	Status	CTR Lead	Supplier Doc No.	Date issued	Doc Type	Comments
Estimate												
SUP-EST-002	SUP	EST	001	Class V Cost Estimate & Levelised Cost Analysis Summary Report	006	0	Comment	SEEL	J-000907-PM-REP-00001	16/09/2022	pdf (doc)	
List												
SUP-LST-001	SUP	LST	001	List of Potential SNS CCS Sites	003	A	Final	Netune	CO2 Store Locations	05/05/2022	ppt	
Model												
SUP-MOD-001	SUP	MOD	001	LCOH Model	006	A	Comment	SEEL	BEH LCOH 15082022	15/05/2022	xls	
Plan												
SUP-PLA-001	SUP	PLA	001	Project Execution Plan	010	A	Final	SEEL				
Profile												
SUP-PRF-001	SUP	PRF	001	Bacton Long Term Gas Lookahead	001	A	Final	Total	Bacton Long Term Gas Lookahead		pdf	
SUP-PRF-002	SUP	PRF	002	Bacton Long Term Gas Lookahead Data 9 Aug 2022	001	A	Final	Total	Bacton Long Term Gas Lookahead Data 9 Aug 2022		xls	
Presentation												
SUP-PST-001	SUP	PST	001	Bacton Enegy Hub Initial Results	006	A	Final	SEEL	Bacton Energy Hub Initial Results (01 Sep 2022)	01/09/2022	pdf (ppt)	
SUP-PST-002	SUP	PST	002	Bacton Energy Hub LCOH Analysis	006	A	Final	SEEL	Bacton Energy Hub LCOH Analysis (08 Sep 2022)	08/09/2022	pdf (ppt)	
SUP-PST-003	SUP	PST	003	BEH Desalination Base Case	005	A	Final	Neptune	NEP-005-SD-002-B1 -	01/02/2022	pdf (ppt)	
SUP-PST-004	SUP	PST	004	Bacton SNS CCS Screening	003	A	Final	Neptune	OPC - Bacton SNS Screening - Neptune - Final	27/09/2022	ppt	
Registers												
SUP-REG-001	SUP	REG	001	Master Document Register	010	A	Final	SEEL			xls	This document
Report												
SUP-REP-001	SUP	REP	001	Blue Hydrogen Technology Review Report	002a	V03	Final	PEL	PEL_Blue_Hydrogen_Technology_Review_20-09-22_v3	31/05/2022	pdf (doc)	
SUP-REP-002	SUP	REP	002	Bacton Supply SIG - Green Hydrogen Scoping Report	002a	0.2	Final	Genesis	J75769A-A-TN-00001 B1-	04/05/2022	pdf (doc)	
SUP-REP-003	SUP	REP	003	Bacton Supply SIG - Green H2 Technology Review	002a	A	Final	Genesis	J75769A-A-TN-00002 B2-	27/04/2022	pdf (doc)	
SUP-REP-004	SUP	REP	004	BEH Supply SIG - Desalination Summary Report	005	B4	Final	Neptune	NEP-005-RP-001-B4 -	08/08/2022	pdf (doc)	
SUP-REP-005	SUP	PST	005	BEH Desalination Site Selection	005	A	Final	Neptune	NEP-005-SD-003-BD -	01/03/2022	pdf (ppt)	
SUP-REP-006	SUP	REP	006	Power Supply Technical Note	004	0	Final	Saipem	Power Supply Technical Note CTR4	23/08/2022	pdf (doc)	
SUP-REP-007	SUP	REP	007	Bacton Supply SIG Project Development Phasing	003	A	Final	Fluor	J75769A-A-TN-000XX-B1-	02/09/2022	pdf (doc)	
SUP-REP-008	SUP	REP	008	Supply SIG Consolidated Report	011	A	Comment	SEEL				
Schedules												
SUP-SCH-001	SUP	SCH	001	BEH Development Schedule	007	A	Comment	SEEL				