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North Sea
Transition
Authority

SCOPING REPORT

Bacton Energy Hub Supply SIG – Green Hydrogen Scoping Definition Report

Prepared for: **NSTA**

Prepared by: **Genesis**
One St. Paul's Churchyard, London, EC4M 8AP, UK
www.genesisenergies.com

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Contents

Figures & Tables

Figures

Tables

ABBREVIATIONS

Bbls	Barrels
BCA	Bacton Catchment Area
CAPEX	Capital expenditure
CO_2	Carbon Dioxide
CTR	Cost Time Resource
CUFT	Cubic Feet
DNO	Distribution Network Operator
GW	Giga Watt
H_2	Hydrogen
H&MB	Heat and Material Balance
HHV	Higher Heating Value
K	Thousand
LCOH	Levilised Cost of Hydrogen
MMcm	Million Cubic Meters
MW	Megawatt
MWh	Megawatt Hours
NTP	Normal Temperature and Pressure
OGA	Oil and Gas Authority
SIG	Special Interest Group
TWh	Terawatt Hours
UK	United Kingdom

HOLDS LIST

HOLD	SECTION	DESCRIPTION
01	1.1	Introduction background text template for all reports as defined by the NSTA
02	1.3	Document numbers
03		

1.0 INTRODUCTION

1.1 Background [HOLD 1]

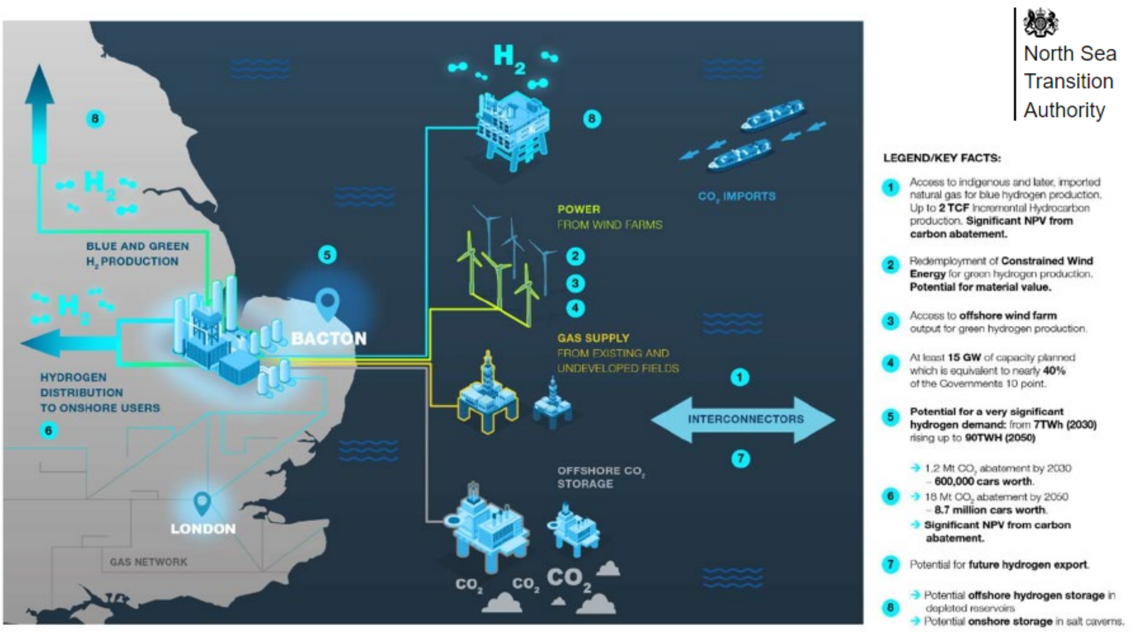
In 2021 the UK North Sea Transition Authority ("NSTA", formally known as the Oil & Gas Authority) commissioned a future vision for the Southern North Sea and Bacton considering the potential role of hydrogen in supporting the delivery of Maximising Economic Recovery and Net Zero. The study area, which is described as the Bacton Catchment Area ("BCA") comprises the Southern North Sea, and the onshore areas defined by National Grid's East of England and North Thames areas.

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 blue hydrogen production
- Access to offshore wind farm output for green hydrogen production
- Availability of offshore structures for carbon dioxide (CO_2) and hydrogen (H_2) storage
- Ample land for development of hydrogen production
- Excellent gas connections to London and the South East of England

These factors combine to make Bacton ideally situated for development as a low carbon hub.

Figure 1-1 Bacton Energy hub Potential Development Scheme



Hydrogen production at Bacton could help to decarbonise not just the study area, which comprises nearly 20% of the UK population, but also to contribute to decarbonisation in London and South East more widely.

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This development would contribute to the UK's decarbonisation targets, and to the recently published "Ten Point Plan for a Green Industrial Revolution", specifically by supporting objectives 1 ("Advancing Offshore Wind"), 2 ("Driving the Growth of Low Carbon Hydrogen") and 8 ("Investing in Carbon Capture, Usage and Storage").

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. Therefore, maturing an extensive list of scenarios at this stage of the project will add little value when considering the key objective for this phase. It is not the intention of this phase of the project to define the technical specification or detailed basis of design of the hub, but rather propose a development concept supported by a scoping level design outline to help frame the potential.

1.2 Study Objective

This study objective is to define a concept supported by a "scoping level design" for a 2.1 GW green hydrogen plant. The basis is underpinned by the "BEH Scenario Summary" (see Appendix B) as outlined:

- 2040: 1 x 2.1 GW Electrolyser
- 2050: 1 x 2.1 GW Electrolyser + 2 x 2.1 GW Electrolyser plants
- Total: 3 x 2.1 GW Electrolyser plants
- Green Hydrogen feedstock assumptions: dedicated wind/solar plus connection to (green) grid (2050)

The study work will focus on a single 2.1 GW plant with a repeated design for 2050.

Three key deliverables are part of the required scope of work (refer to the green hydrogen CTR in Appendix A) as listed below:

1. Production facility technology readiness report (Completed by Genesis *J75769A-A-TN-00002 B2-Bacton Supply SIG - Green H2 Technology Review*)
   - Review and identify Green Hydrogen technologies
   - Technology availability and anticipated development (upscaling)
   - Discussion of Bacton phasing and how the right technology may change before FID is reached or even between development phases
2. Production facility sizing/scoping
   - Phasing
   - Storage
3. Production profiles for Green Hydrogen, phased
   - Will be part of deliverable 2 above.

1.3 Document Purpose

The purpose of this report is to summarise the scoping definition for a 2.1 GW Green Hydrogen Plant to generate likely development concept including:

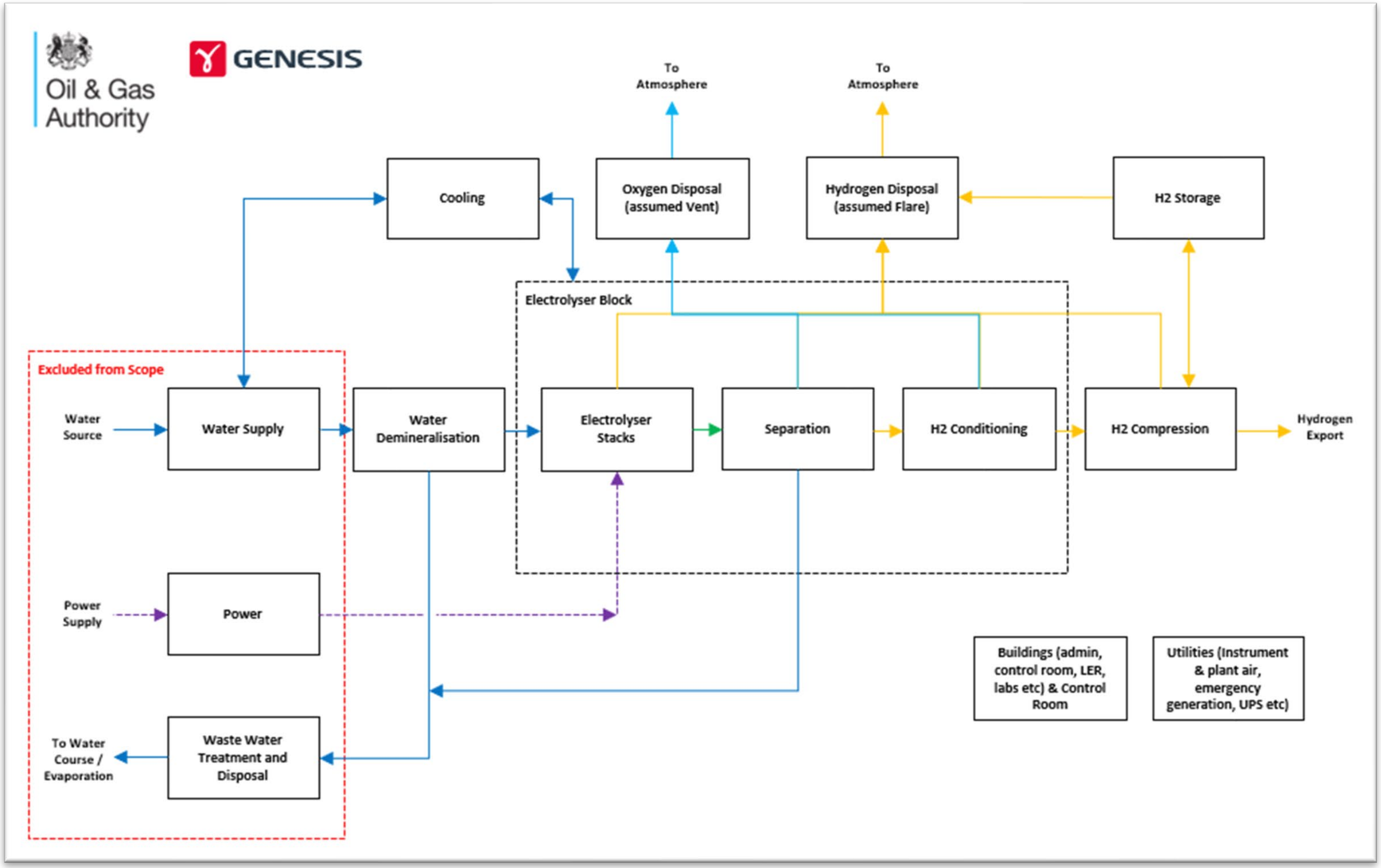
  - Sizing
  - Phasing
- Storage

This report also includes the basis underpinning the scoping definition for the plant, preliminary sizing and key areas to be focused on for the next phases of the development.

This report excludes the following:

- Costs. This will be covered in a separate report by the Supply SIG leader [Hold 2].
- Layouts. This will be covered by the Infrastructure SIG [Hold 2].
- Wind and Power Supply. This will be covered by others in the Supply SIG [Hold 2].

Figure 1-2 Bacton Green Hydrogen Plant Battery Limits


Oil & Gas Authority
GENESIS
To Atmosphere
To Atmosphere
Cooling
Oxygen Disposal (assumed Vent)
Hydrogen Disposal (assumed Flare)
H2 Storage
Electrolyser Block
Excluded from Scope
Water Source
Water Supply
Water Demineralisation
Electrolyser Stacks
Separation
H2 Conditioning
H2 Compression
Hydrogen Export
Power Supply
Power
Buildings (admin, control room, LER, labs etc) & Control Room
Utilities (Instrument & plant air, emergency generation, UPS etc)
To Water Course / Evaporation
Waste Water Treatment and Disposal

2.0 BASIS OF DESIGN & ASSUMPTIONS

The plant battery limits are defined as illustrated in Figure 1-2. The basis of design and assumptions underpinning the scoping definition of the plant are summarised below.

2.1 Conversions

The following conversions will under pin the study [Ref. 1]:

- 1 tonne of hydrogen = 39.4 MWh = 11,200 Nm^3 = 395,000 cuft (at NTP)
- 1 TWh of hydrogen = 10 billion cuft (at NTP) = 285 MMcm (at NTP)
- Based on Higher Heating Values (HHV)

2.2 Battery Limits

The battery limits are outlined below and reflected in the red box in Figure 1-2.

- **Onshore** only
  - Offshore may be considered in future development phases
- Supplied **power source** at boundary fence
- Supplied **water source** assumed water pipeline at boundary fence
- **Hydrogen export** at 80 barg at boundary fence for industry use and pipeline blending
  - Only buffer storage for fluctuation management (small scale or line packing)
- **Oxygen** is vented
  - Potential for oxygen and waste heat utilisation with the blue hydrogen plants, to be investigated in future phases

2.3 Exclusions

The following are excluded from scope:

- Large scale storage including geological onshore or offshore storage (assumed part of infrastructure SIG)
- Hydrogen for mobility (compressed to >350bar) (this market is currently undefined)
- Wind and transmission lines; grid connection (part of power scope)
- Water connection and pipeline (assumed part of infrastructure SIG)
- Hydrogen export pipeline (assumed part of infrastructure SIG)
- Battery storage (optimisation for power scope and future study phases)
- Other hydrogen vectors including but not limited to Ammonia, Liquid Organic Hydrogen Carriers (LOHC), Liquid Hydrogen (LH_2) (the markets are currently undefined by BEH)
- Wastewater treatment and disposal:

  - Wastewater from the Demineralisation Treatment System will be generated, typically 10-15% of feedwater
  - The wastewater treatment and disposal should be studied in next phase once the BEH concepts are further defined. Options for shared treatment/disposal include existing local utility company or combining with future blue hydrogen plants should be considered.
- Green Hydrogen CTR (Appendix A) indicates “blending requirements”, this is assumed not part of scope.

2.4 Assumptions

- Green Hydrogen Plant is **onshore and standalone**, separate from the Blue Hydrogen plants
  - Why? Offshore is immature, more expensive. The blue hydrogen plants have different construction timings.
  - Impact? Potential synergies with the Blue Hydrogen plants such as flare, utilities, construction etc to be assessed in following phases of development.
- **Power source** is assumed offshore wind with grid connection is configured such that the grid infeed is primary with synchronised behind the meter wind power to compliment the power source. There will be no requirement for 'switching' between power sources, there would be an input from both sources, with a reduced import from Grid when wind is high.
  - Why? Secure supply of power to the green hydrogen plants to minimise impact of intermittent supply.
  - Impact? Power / renewable supply SIG. Significant impact on grid connection requirements.
- **Water Source** is assumed to be supplied by local water authority (tap water quality, reliable supply) or from a potential desalination plant.
  - Demineralisation water treatment required for green hydrogen plant and assumed water buffer storage for 1 day only.
  - Why? Seawater with small desalination plant excluded due to cost, large power required and saline reject stream. Note, a potential desalination plant is under review by others in the Supply SIG which can supply water to the green hydrogen plant.
  - Impact? Desalination plant requirements.
- **Hydrogen produced**
  - The summary table in the “BEH Scenario” document (Appendix B) states Electrolyser capacity in GW units. This is confirmed as the electrical capacity of the electrolyser plant.
- The **technology review** will provide a view on the outlook of future technology and efficiencies. For this feasibility study, the analysis will be based on mature electrolyser technology and current sizes.

- Alkaline technology, no account for future efficiencies or technology improvements in efficiency or physical size in this study phase.
- Why? Generic design only for concept scoping including layout.

- **Flare** it is assumed the green hydrogen plant will have a flare at GW scale.
  - Not for steady state operation, emergency scenarios only.
  - A stack height and sterile area will be assumed.
  - Safety systems for green hydrogen at scale are immature industry wide. Need to consider the ignition case with a vent, therefore flare considered "worst case" design.
  - Why? Prevention of escalation in fire case at plant (see Section 4.10 for further details).
- **Cooling**: Cooling is required for electrolysers (20-35% stack load is heat generated) and for the compressors.
  - Study will be based on air cooling.
  - Why? Simpler design and excludes cooling medium.
  - Impact? Overall power or water supply, infrastructure SIG for required plot area.
- Target **Plant Availability** 95%
  - To be determined if achievable in subsequent phases and to define equipment sparing requirements.
  - Why? High availability required for hydrogen exports, particularly pipeline blending – typically by contractual obligation.
- The **green hydrogen is constructed** in 200 MW instalments
  - Phasing to be optimised in subsequent study phases
  - Why? Electrolyser stacks require replacement approximately every 10 years and developments at this scale lends itself naturally to phased development and phased electrolyser replacement.
- It is assumed **land is available** at the Bacton.
  - It also assumed areas of allocation between green, blue and CCUS will not be defined at this stage and forms part of the Infrastructure SIG scope.
  - Impact? Infrastructure SIG.
- Facility **Design Life** of 20 years [Ref. 3].

3.0 HSE – GASEOUS HYDROGEN

The fluid characteristics of Hydrogen are important to understand for design. Typical characteristics include, but are not limited to:

- Leak tendency due to:
  - Low viscosity;
  - Extremely high diffusivity;
  - High buoyancy.
- Ignition inclination:
  - Wide range of flammability;
  - Extremely low ignition energy;
  - Ability to spontaneously ignite on release to atmosphere.
- Material Compatibility:
  - Hydrogen embrittlement of high strength steels;
  - Titanium alloys and aluminium alloys resulting in cracking and catastrophic failure of the metals at stress below the yield stress.

Technical safety is relatively immature for green hydrogen plants at scale and special consideration must be given to safety design and learning from other green hydrogen plans to be built (prior to Bacton). The text below is from the *Hydrogen Tools* Website [Ref. 4].

Hydrogen is colourless, odourless, tasteless, non-toxic, and non-poisonous. It's also non-corrosive, but it can embrittle some metals. Hydrogen is the lightest and smallest element, and it is a gas under atmospheric conditions.

Hydrogen is about eight times lighter than natural gas and fourteen times lighter than air. This means that if it is released in an open environment, it will typically rise and disperse rapidly. This is a safety advantage in an outside environment.

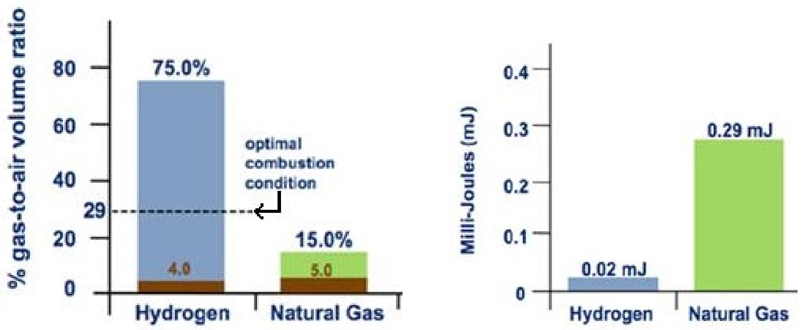
Hydrogen is a very small molecule with low viscosity, and therefore prone to leakage. In a confined space, leaking hydrogen can accumulate and reach a flammable concentration. Any gas other than oxygen is an asphyxiant in sufficient concentrations. In a closed environment, leaks of any size are a concern, since hydrogen is impossible for human senses to detect and can ignite over a wide range of concentrations in air. Proper ventilation and the use of detection sensors can mitigate these hazards.

Hydrogen has a high energy content by weight, but not by volume, which is a particular challenge for storage. In order to store sufficient quantities of hydrogen gas, it's compressed and stored at high pressures. For safety, hydrogen tanks are equipped with pressure relief devices that will prevent the pressures in the tanks from becoming too high.

The auto-ignition temperature of a substance is the lowest temperature at which it will spontaneously ignite without the presence of a flame or spark. The auto-ignition temperatures of hydrogen is ~538 Degrees C (very similar to natural gas).

Hydrogen's flammability range (between 4% and 75% in air) is very wide compared to other fuels. Under the optimal combustion condition (a 29% hydrogen-to-air volume ratio), the energy required to initiate hydrogen combustion is much lower than that required for other common fuels (e.g., a small spark will ignite it) but at low concentrations of hydrogen in air, the energy required to initiate combustion is similar to that of other fuels.

Figure 3-1 Flammability Range and Minimum Ignition Energy



Hydrogen burns with a pale blue flame that is nearly invisible in daylight, so it is almost impossible to detect by the human senses. Detection sensors are almost always installed with hydrogen systems to quickly identify any leak and minimize the potential for undetected flames. The hydrogen flame is almost invisible, but it can be seen with the thermal imaging camera shown in the foreground. At night, hydrogen flames are visible.

In addition, hydrogen flames radiate little infrared (IR) heat, but substantial ultraviolet (UV) radiation. This means that when someone is very close to a hydrogen flame, there is little sensation of heat, making inadvertent contact with the flame a significant concern. UV overexposure is also a concern, as it can result in sunburn-like effects.

If a large hydrogen cloud comes into contact with an ignition source, ignition will result in the flame flashing back to the source of the hydrogen. In open spaces with no confinement, flames will propagate through a flammable hydrogen-air cloud at several meters per second, and even more rapidly if the cloud is above ambient temperature. The result is a rapid release of heat, but little overpressure, and the combustion product is steam. It should be noted that hydrogen combustion is more rapid than combustion of other fuels. A hydrogen cloud will burn within seconds, and all of the energy of the cloud will be released.

However, if hydrogen gas mixtures enter confined regions, ignition is very likely and can result in flame acceleration and generation of high pressures capable of exploding buildings and throwing shrapnel. Flammable mixtures of hydrogen in confinements such as pipes or ducts, if ignited, will readily result in accelerated flames and conditions that can lead to transition to detonation. Detonation does not occur in unconfined hydrogen-air mixtures without strong shockwaves (i.e., explosives).

A leak in a pressurized (>14 bara) hydrogen storage system will result in a jet that may extend for some meters. If ignited, the jet flame can cause serious damage to anything it encounters.

These characteristics of hydrogen must be considered in the plant design, particularly at scale. The minimum safety requirements, assessments, and considerations for ensuring that the risks associated with the design are to be reduced to a level which is as low as reasonably practicable (ALARP).

4.0 GREEN HYDROGEN PLANT - SCOPING DEFINITION

The following sub sections define a concept for a 2.1 GW green hydrogen plant, supported by a scoping level design. Many aspects will need further developing following basis decisions and further understanding of the Bacton hydrogen markets.

4.1 2.1 GW Green Hydrogen Plant Rates

The table below presents an overview of feedstock and production rates of the 2.1 GW Plant.

Table 4-1 Material Balance Overview

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	-

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/kgH_2.

The water feedstock includes typical wastewater treatment loss of ~10%.

4.2 Power Source

The power source for the first 2.1 GW green hydrogen plant is assumed to be from offshore wind with grid connection, configured such that the grid infeed is considered as primary as grid power is the reliable source of power, with synchronised behind the meter wind power to compliment the power source. There will be no requirement for 'switching' between power sources, there would be an input from both sources, with a reduced import from Grid when wind is high.

The details of the power source will be covered in a separate report [HOLD 2], and it has been assumed that any infrastructure upgrades to support the green hydrogen plants will be in place by 2040 and pre-invested by the development. It is estimated (using a generous value based on future improvements to technology) that the wind farm would have a capacity factor (load factor) of circa 60% using IEC class 3 offshore fixed wind turbines. Therefore, with an installed nameplate capacity rating of 2.2 GW, there would be a requirement to import circa 880 MW on average from the Grid. During periods with high wind speeds available the output would be higher and much closer to the installed capacity, but over the year, the actual power output would average a much lower value. Therefore, the design team on the project would need to investigate the maximum installed capacity of wind turbine to optimise CAPEX investment for offshore power generation infrastructure compared with the power import costs over the life of the facility.

4.3 Electrolysers

The design chosen for this 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.

It is expected that in due course, separation trains larger than 20MW will be available and different projects are considering how to scale up. Investigation of options to scale further is recommended in future phases of this project and also a robust electrolyser technology selection process (Refer to Genesis Report J75769A-A-TN-00002 for details on criteria used to screen technology and vendor selection).

For 2.1 GW plant, 105 off 20MW modules would be required. This is not optimised and must be further assessed in future stages of work. The layout requirements are further discussed in Section 4.16.

4.4 Plant Electrical Load List

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

Table 4-2 Electrical Load List

ITEM	Quantity	Rating	Total Load (MW)
1st & 2nd Stg Compressor & Coolers	4	33%	33
Electrolyser Coolers	65	2%	7.3
Chilled Water & Dehyd. Regen Air Coolers	11	11%	1.1
Dehydration Heater	1	100%	3.2
Alkaline Electrolysers	420	0.2%	2,100
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**

Note: majority of the buildings power is required for the Electrolyser HVAC requirements.

For study design purposes, the following voltage levels are assumed:

- Consumers 10 MW to 50 MW — 33/11 kV AC, 50 Hz, 3-phase
- Consumers 150 kW to 10 MW — 11 kV VAC, 50 Hz, 3-phase
- Consumers 2 to 150 kW — 400 VAC, 50 Hz, 3-phase
- Consumers below 2 kW — 230 VAC, 50 Hz, 1-phase

It should be noted that vendors accept an import voltage of either 11 kV or 33 kV for each electrolyser package. It has been assumed for this study that the electrolysers have an import voltage of 33 kV to optimise the quantity of switchgear.

4.5 Electrical Import & Power Distribution

Power Import will be from an offshore wind farm which should be designed and optimised to support the facility the majority of the time, based on average wind speed and power densities in the area. Although the intention should be for all power to be taken form the wind source, the grid will be considered as the primary source of power as it is considered as reliable. Wind power will inherently have peaks and troughs of power availability, which reduces the reliability of the source. The wind power source should be connected behind the meter in parallel with the grid source to ensure maximum power availability and reliability is optimised.

To support a 2.2 GW (see Table 4-2) power import feed, grid import voltage level will be in the region of 400 kV based on a practical current carry capacity of the busbars. Therefore, a grid connection at 400 kV would be required to support the facility full load. If it were proposed that the grid only to support the facility at a turned down loading, when offshore wind was unavailable, then this tie in voltage level may be decrease, depending on the agreed maximum load during this period.

Power distribution has been considered at 33 kV, 11 kV and 0.4 V to support he proposed users. It would be assumed that a dual feed distribution power philosophy would be adopted to ensure a high available and reliability throughout the facility. To support power distribution, it has been assumed that there would be a main import 400 kV GIS switchboard which would feed into circa 10 numbers of 33 kV switchgear to support the main electrolyser packages and larger facility loads. The 400 kV switchboard would also feed the 11 kV switchboards which would in turn support the lower rated MV package loads. The LV switchboards would be fed from the 11 kV network. It would be proposed that the electrical distribution be split across several substations to allow for optimal LV distribution throughout the site. Power transformation between voltage levels would be proposed with 2 x 100% power transformers to each switchboard to allow for high reliability and availability throughout the power network.

Although it has been proposed that the grid and wind power source are available in parallel, a concept where wind power source only could be considered, but there are several challenges that would need to be considered during the design phase of this project. Typical challenges include turndown of facility during low wind/ no wind periods, smoothing of the power available as it fluctuates, support for starting any large dynamic loads that are connected direct on line and general energisation of the facility from a black start scenario. Several of these challenges would also be present with the grid backed concept, with the additional of large power factor correction and power conditioning to meet minimum electrical tolerances stipulated by the grid DNO at the point of common coupling. And off grid concept would need to consider a significant amount of energy storage (technology maturity under development) within the facility to assist in smoothing the power availability and to support any sudden changes to power import levels.

It is recommended that the project consider full pre-investment for the key electrical equipment for each stage of the project, e.g. for the 2.2 GW phase 1 concept, all main switchgear (400 kV switchyard/ 400 kV GIS Switchgear) and main site distribution transformers are rated for full load based on the philosophy for the 2.2 GW facility and have sufficient panels to support full facility site distribution. It is assumed future phase 2 phase would follow a similar distribution philosophy as phase 1, but would consider a separate import supply and distribution network per 2.2 GW block, and in each case the key equipment should be pre-invested for the 2.2 GW loading.

The full study for these concepts would need to include a detailed side study into the efficiencies of the equipment throughout the plant as there will be compounded losses throughout he system as you step up the voltage levels, for example, the 5 MW electrolyser stack requires 4,800 kW of DC power at full capacity. The conversion from AC/DC and the stepping down of the high distribution voltages incur losses that increase the power requirement at the plant boundary.

There are several high level risks around the power aspects of these concepts. A key risk is related to whether the grid would be capable of supporting the levels of connected loads for this project. The loads for this project are relatively large and would require significant electrical infrastructure (Generation and Transmission) to be installed by the power grid company to support this project. These costs would be passed onto the project. Another key risk that would need to be considered during the engineering is how the windfarm would tie in to the facility, and at what voltage level. The electrical infrastructure to accommodate the power import form the wind farm would significantly increase the area required in or around the facility to support the Wind Farm collector substations, and power connections between the wind farm collector substations and facility import switching yard/ substation. It has been assumed that the wind power would be stepped up to tie in to the facility at 400 kV to simplify the connection at the battery limits.

4.6 Compression

To date, reciprocating compressors have generally been preferred for hydrogen applications. For centrifugal compressors the low molecular weight of hydrogen results in low compression ratios per stage for centrifugal compressors. For proven centrifugal compressor designs, this lower pressure rise per stage, requires compressors to have a significant number of stages, and if the discharge pressure is high, multiple casings are required, hence the preference for reciprocating compressors. Refer to Genesis *J75769A-A-TN-00002 B2-Bacton Supply SIG - Green H2 Technology Review* for more details on technology.

Reciprocating compressors have been assumed for robustness though emerging centrifugal compressor technology presents an optimisation for future phases.

4.7 Demin Water

The electrolysers require a supply of demineralised (demin) water for electrolysis. The demin technology will depend on the feed water quality, i.e. desalinated water only needs ion exchange, whilst raw/potable water will need Reverse Osmosis (RO) and ion exchange technology.

For Bacton, it has been assumed the demineralised water package will be supplied with potable water. A demineralised water tank has also been included and sized for one day storage in case of any disruption to the potable water supply. The source water connection and storage requirements will need to be confirmed with the local authority.

4.8 Effluent Disposal

The main liquid effluent from the green hydorgen plant is the demin reject water. It is recommedned that the disposal of the efflucent is assessed holistically with other developments within the Baction Energy Hub.

For the green hydrogen plant, the demin water produces reject water stream which is roughly 10-15% of the incoming water (~40-60 m^3/h) and will be concentrated in dissolved salts. This will require treatment prior to disposal.

A study will be required to determine best approach for treatment and disposal of all effluent streams resulting from the blue, green hydrogen and CCUS Bacton developments. The study should consider local disposal options.

4.9 Cooling

A cooling system is required to cool the electrolyser converters. Air Cooling has been assumed for Bacton.

- The cooling duty can be as much as ~25-30% of the electrolyser duty. i.e 25% of electrical power is lost to heat (25% of 2.1 GW ~500MW heat)
- Air cooling was tested to alleviate the significant demand on water required for the Bacton Energy Hub

High level analysis has indicated over 70 air coolers required for a 2.1 GW green hydrogen plant. Although air cooling for compression is simple and effective, the cooling requirements for electrolysers is significant and will require significant plot space to locate the air cooler farm. Installation of air coolers above piperacks could be considered for optimising plot space (e.g., as adopted by LNG plants which require large numbers of air coolers).

A techno-economic study is required to evaluate the requirements for a desalination plant versus air cooling, including an evaluation of the overall plot requirements, CAPEX, OPEX, power requirements, effluent disposal, carbon footprint etc.

4.10 Flare & Vents

Hydrogen is not considered a greenhouse gas; however, it is thought to be an indirect contributor. Hydrogen may be vented in small quantities though larger quantities may require to be flared for both environmental reasons and the safety of the plant and personnel. The impact of NOx should also be considered.

An elevated flare system has been assumed for the relief of hydrogen for safe disposal under emergency plant conditions. A flare is required for disposal of combustible gasses either during start-up or shutdown operations, or because of a plant upset or emergency. <u>Continuous flaring is not required or expected during normal operation.</u> A single flare is proposed for all combustible gases; however no design work has been performed at this time to verify green hydrogen flare systems (or vent systems) at scale for Bacton. Study work will be required to verify whether separate flares are required for low pressure/ high pressure/ hot/ cold streams.

The key function of the flare is to:

- Prevent overpressure and potential uncontrolled release of hazardous fluids.

- Depressurise sections of the hydrogen generation plant in an emergency situation.
- Allow maintenance and commissioning activities to be completed safely.
- Minimise any domino effects on adjacent sites or facilities.

The NASA Safety Standard for Hydrogen and Hydrogen Systems [Ref. 5] states:

The allowable quantities of hydrogen that may be vented are subject to conditions such as wind direction, wind velocity, proximity of inhabited buildings, vent stack height, local discharge limitations, or other environmental restrictions. Quantities of hydrogen of 0.113 to 0.226 kg/s (0.25 to 0.50 lb/s) have been successfully vented from a single vent 5 m (16 ft) high (NASA TMX-52454 1968). Multiple roof vents at least 5 m (16 ft) apart across the prevailing wind may be used. The use of multiple vents is preferred rather than using a collection header and a single vent stack for multiple sources requiring venting.

Larger quantities of hydrogen that cannot be safely handled by roof vent systems are best disposed of in a burn-off system in which the liquid or the gas is piped to a remote area and burned with air in a multiple burner arrangement. Such systems shall have pilot ignition, warning systems in case of flameout, and means for purging the vent line. The design of a hydrogen disposal system also must provide sufficient assurances of the following:

(a) Hydrogen issuing from the flare stack will be disposed of safely.

(b) The flare stack system will prevent explosions within the stack.

(c) The radiation flux levels from burning hydrogen will not harm personnel or damage the facility.

Diffusion flames are most frequently used in flare stack operations. Combustion air comes from the open atmosphere round the downstream end of the stack and is not mixed with the hydrogen within the stack. Although disposing of hydrogen by flaring is essentially safe, hazards do exist. The hazards are flame stability, flame blowoff, and flame blowout.

The flare system shall be designed to cater for the worst foreseeable combination of the following types of release:

- Single largest pressure relief.
- Largest combined fire relief case.
- Pressure controlled vent valves provided at strategic points in the process to allow the process gas flow to be sent to flare, in the event of high system pressure.
- Emergency Depressurising. The peak blowdown flowrate shall be considered. It is anticipated that the peak blowdown load will not exceed the blocked outlet flow.

The disposal system shall be designed to ensure thermal radiation generated does not pose a risk to personnel and the environment and comply with established thermal radiation criteria. The design (height and location of the flare tip) should ensure that account is taken of wind direction, wind strength, the topography of the location. Dispersion modelling should be carried out in future phases to ensure the hydrogen is safely released. This is a very immature aspect of green hydrogen plants at scale, in general.

4.10.1.1 Vents

The electrolysis of water will produce oxygen as a by-product. At this project phase, it is assumed the oxygen will be vented at the point source (oxygen separator). Oxygen could be monetised as an input for metal refining, chemicals, pharmaceutical and petroleum processing, and this, also integration with the blue hydrogen plant and should be explored in the following phases of development.

Hydrogen is also lost in low pressure vents located on the hydrogen/water separation section and the de-oxidiser condensate vent at the electrolysers. This can vary from 0.5-2% of total Hydrogen production.

4.11 Other Utilities

Instrument air is supplied to users including valve actuators, positioners and controllers. An instrument air receiver is included to provide hold up for package trips and compressor changeover, as well as providing hold up during emergency shutdown.

A nitrogen receiver is included to provide nitrogen for start-up, purging of the electrolysers and as a seal gas for the hydrogen compressors.

The drains system includes a closed drain system and non-hazardous open drains systems consisting of tanks and pumps.

Emergency power generation is required for life support systems e.g., in an event electrical power is lost for emergency lighting, nitrogen purging etc. It has been assumed that an emergency diesel generator will provide this. However, hydrogen power generation could also be considered to ensure no emissions.

Other minor utilities include potable water for safety showers and other consumptions and sanitary waste system etc.

4.12 Pipeline sizes

High level pipeline sizes have been estimated for a single 2.1 GW plant as shown in the table below.

Table 4-3 Material Balance Overview

PIPELINE	2.1 GW PLANT	2.1 GW PLANT
Water Feedstock Pipeline	380 m^3/h	10-12”
Hydrogen Export Pipeline	36, T/hr	14-16”

Notes

- Should the pipeline be used for line pack, the hydrogen export line will need to be larger in diameter than indicated above to provide the storage capacity.
- The preinvestment strategy may consider preinvestment of the pipelines for the future green hydrogen plants.

4.13 Materials

Materials of construction for both the plant, storage and the hydrogen export pipeline are very important considerations.

Long distance and high-pressure pipelines are at risk of hydrogen permeability due to the "small molecules", particularly if cycling pressure for line pack. In general, pipelines for hydrogen transportation are traditionally carbon steel with grade X52 widely used and pipeline design and qualification of the pipeline usually to ASME B31.12. The key requirement is to prevent water condensation within the pipeline.

4.14 Storage

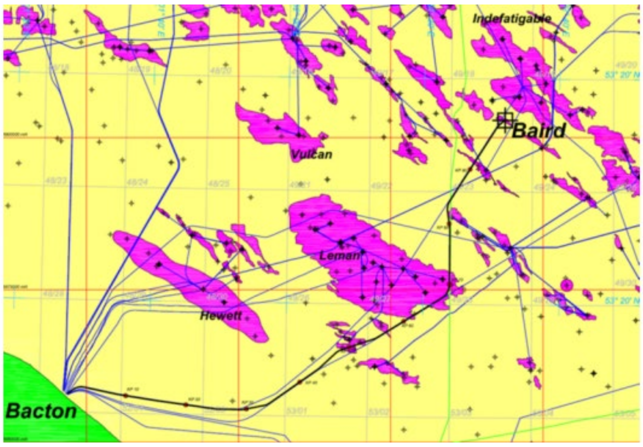
Hydrogen has a very low density, potentially requiring very large storage that could comprise a significant proportion of the total overall plant costs and plot space. Storage is required to provide a buffer for supply, owing to the intermittency of the hydrogen generation from renewables, and due to the periodic offtake of some supply chains.

Various options for storage have been considered as discussed in the Genesis *J75769A-A-TN-00002 B2-Bacton Supply SIG - Green H2 Technology Review* and outlined below:

- **Line pack** method for storage is widely used in the current natural gas network for the compensation of small daily variations. For Bacton, the line pack requirements for daily fluctuations for first plant only have been evaluated (at a high level):
  - Based on 6 hours storage requirements, a storage capacity of 216 Te is required.
  - To pack a pipeline from 80 bar and assuming a 100 km pipeline then:
    - A pipeline diameter of 16” requires a very high compression pressure of ~350 bar or
    - A pipeline diameter of 24” requires a compression pressure of 195 bar.
  - A cost-benefit analysis is recommended to determine the benefits of a smaller pipeline diameter, higher compression requirements compared to larger pipeline diameter, lower compression requirements.
- **Compressed gas cylinders** are a well-established technology and have been used in hydrogen for many years. Vendors have varying storage solutions to store such as storage of 1 Te of hydrogen at 350 barg in a 40' shipping container with multiple cylinders stacked. For 6 hours of storage, Bacton would require 216 x 40’ containers.
- Larger typically steel **pressure vessels** can also be used for storage of hydrogen (small scale) however, they are limited by the trade-off between high pressure (gives more hydrogen storage) and steel mass (increase cost and makes transportation and installation more complicated). Use of such vessels is underway on projects in Spain with tanks capable of storing ~0.5 tonnes each. These vessels are 23m x 2.8m (OD) each. For Bacton’s first green hydrogen plant, 432 containers would be required.
- **Vertical shaft storage** technology an emerging storage option adapted from proven drilling techniques to store a vessel in an underground cavity. This allows the surrounding rock to bear the stress of the compressed hydrogen and has a smaller topsides footprint. Shafts have a storage capacity of 50-500 tonnes of hydrogen per shaft.

- For seasonal storage, **geological storage** could be an option for Bacton. Immediate screening did not identify local salt caverns. However, depleted hydrocarbon reservoirs and aquifers offshore maybe an alternative option such as Rough or Baird. It is currently unclear whether storage in the gas fields is feasible.
  - The Baird field is located offshore, approximately 86 kilometres northeast of Bacton and also offers a transport route of hydrogen to Europe.
  - The Rough reservoir, located offshore in Humberside, stored natural gas safely for over three decades. A repurposed Rough has the potential to provide around half of the UK's hydrogen storage requirements [Ref.6] and is currently being assessed by Centrica.

Figure 4-1 Area Map Showing the Location of the Baird Reservoir [Ref. 7]



Storage requirements for Bacton will need to be optimised with power requirements (wind, grid vs power storage) and the required markets (contractually obliged for continuous supply).

4.15 Equipment Packages

The major equipment packages are summarised in the table below:

Equipment Packages & Major Package Dimensions

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

System	Equipment Details	Approx. Area Required (m^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 General Distribution Boards	Estimated that substation buildings will require a total area of circa 5000m^2 It is recommended multiple substation buildings are used (2 or 3 depending on overall layout) to optimise LV distribution throughout the site
Outdoor Switchyard	Transmission line end disconnectors, breakers, isolators, HV instruments and transmission related VAR compensation	Assumed to be Circa 100m x 85m
Instrument Air & Nitrogen Packages	Instrument & Plant Air Inert Gas Generation Package	70m^2
Drains	Closed drains vessel & pump Hazardous Drains and Pump	7m^2
Fire Protection	Pumps and Water Storage (topped up from main)	1200m^2
Demin Package & Storage	RO unit, Demin unit, Storage Tanks and Pumps	3000m^2
Hydrogen Storage		
Buildings:	(See above for electrolyser & LER Buildings)	
	Control Room	500m^2
	Workshop	1000m^2
	Admin Building	4000m^2
	Gate House	200m^2

Notes:

- If HP electrolyser type was selected (~30 bar discharge pressure), significant compression (~10 MW) and Cooling (~10 MW) and footprint (~250m^2) can be saved. The energy required to compress 2.1 GW of Hydrogen from ~18 bar to ~ 30 bar is significant due to hydrogens low molecular weight.
- Sparing is not optimised. The development will require a RAM study to ensure required availability is met (based in export routes and commercial agreements) and the sparing philosophy is suitable for required availability target.

4.16 Layout

Detailed plot plans have not been developed at this stage of the scoping study. High level layouts will be developed by the Infrastructure SIG using the high-level package dimensions indicated in Section 4.15 to ascertain if there is sufficient plot space available to locate the three green hydrogen plants at Bacton.

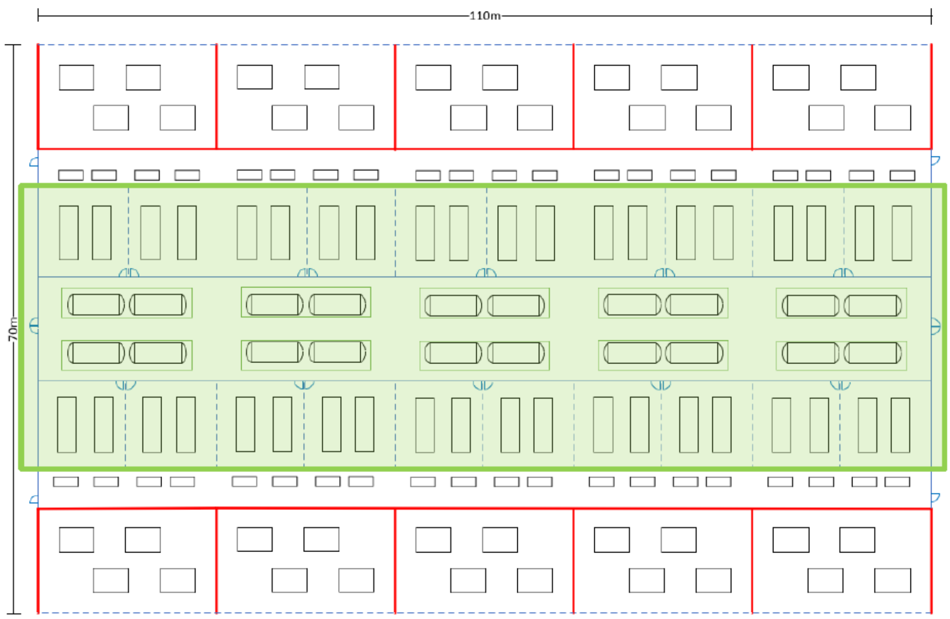
In the next phases of the Bacton development, site layouts should be generated based on more detailed assessments: allowing for typical safety distances, and layout principles for construction and plant operational requirements, as well as industry guidance layout requirements. Ignited hydrogen release 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 4-2 Layout for 10 x 20 MW Trains into a 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 are:

- 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.

Moreover, the process safeguarding and emergency response philosophies for the proposed concept shall require development, taking into consideration industry guidance and local regulatory framework considerations.

4.17 Turndown

Managing daily and seasonal fluctuations is a very important aspect of hydrogen export.

- An important point is to differentiate the overall plant turndown from individual stack or module turndown. Stack turndown does not necessarily dictate the overall plant turndown.
- Deoxygenation vessels, or dehydration media (molecular sieves/ membranes), have a limited ability to operate at low flow rates due to distribution and mal-operation issues.

Similarly, compressor configuration and individual compressor turndown will determine to what extent the production can respond to a varying source power supply.

- Pressure cycles can adversely impact the electrolyser design life (i.e. depressurising the system and then re-pressurising) and hence operatbilty is very important.

4.18 Phasing

Currently, typical for vendors to provide electrolyser plants in 100MW to 250 MW arrays. This is expected to improve as technology innovates. Phasing should consider:

- Optimisation of stack replacement (every 10 years depending on vendor)
- Installation
- Turndown
- To be designed further once the hydrogen markets and power source are further defined.

For Bacton, it has been assumed that the development will be phased by installation of 200 MW arrays (10 x 200MW + 1 x 100MW arrays) over approximately 4-6 months (assuming suppliers can manufactory and ship as required for the project).

4.19 Preinvestment

Preinvestment for green hydrogen development (total 3 x 2.1 GW plants) may include the following areas of the plant and will be dependent on location of the three green hydrogen plants:

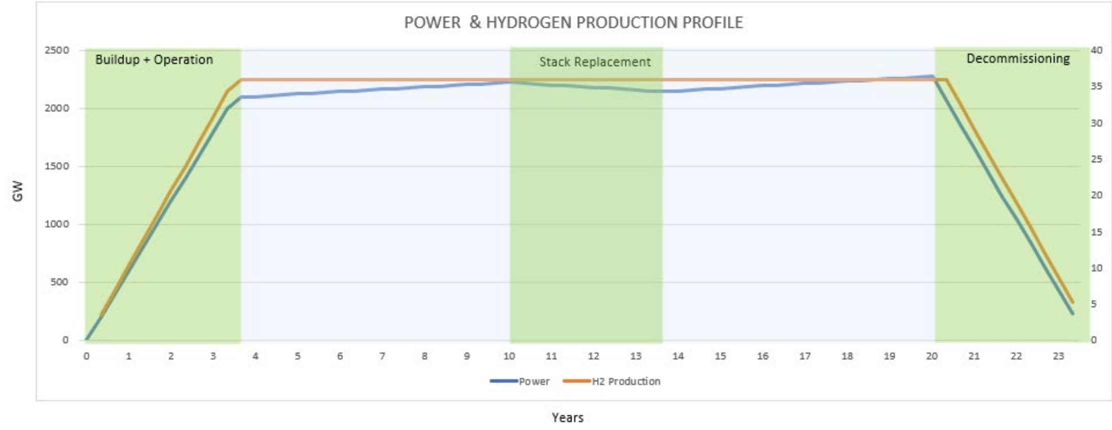
- Electrical & power source requirements – assumed a given for preinvestment.
- Utilities – demin water, control rooms, building rooms etc
- Pipeline. This can be decided once the offtakers and markets are better understood – may be more economical to preinvest.

A cost benefit analysis will need to be performed to understand the economics of preinvestment.

4.20 Production vs Electrolyser Power Profiles

To maintain a constant hydrogen production throughout design life of the electrolysers (20 years), an increased power is required to substitute for power degradation of the electrolyser over time. The plant will also require more cooling as electrolyser power degrades. The profile below illustrates power and production increasing over 3.5 years as 200 MW arrays are installed every 4 months to a total of 2.1 GW. In year 10, the stacks will require replacement and again, it has been assumed 200 MW electrolyser arrays will be replaced at a time. It has also been assumed this will take 4 months, however, it may be less depending on like for like replacement or new technology.

Figure 4-3 Power and Hydrogen Production Profile – 2.1 GW Green Hydrogen Plant


POWER & HYDROGEN PRODUCTION PROFILE
Buildup + Operation
Stack Replacement
Decommissioning
GW
Years
Power
H2 Production
0
500
1000
1500
2000
2500
0
5
10
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5.0 KEY RISKS & OPPORTUNITIES

5.1 Risks

The key risks for the 2.1 GW green hydrogen production plant are summarised below:

- **Power Source**
  - Risk: renewable power and grid capacity cannot supply required power to Bacton.
  - Risk: power supply is unstable impacting plant performance and ability to deliver hydrogen to market.
- **Electrolyser costs**
  - Risk: cost of electrolysers increase in future (and not decrease as predicted). Recent price of noble metals like iridium, platinum, as well as other metals like copper and aluminium have been fluctuating significantly.
  - Risk: Supply chain constraints due to demand for green hydrogen technology outstripping manufacturing capability.
- **Safety Design**
  - Risk: plant design is immature for green hydrogen plants at scale and may impact design, cost estimates, required plot space etc.
  - Risk: technical or safety design Standards for hydrogen generation, storage or use may change, or new standards may be introduced.
- **Uncertain markets**
  - Risk: Bacton markets are not fully defined or secure. This will impact plant size, power source and storage requirements, costs etc.
- **Regulatory approvals**
  - Risk: environmental, health and safety regulations, permits and licences are not obtained.

5.2 Opportunities

- Explore other **options for hydrogen usages** including mobility and other hydrogen derivatives such as ammonia.
- **Target Market:** Defined export routes may allow for optimisation of compression and storage requirements.
- **Technology innovation** including electrolyser pressure, stack/module/array size, technology (see technology review report on electrolyser and storage).
- **Integration with the Blue Hydrogen plants** including construction, utilities, waste disposal etc.
- **Optimising layout** including electrolyser plant and cooling, this will significantly benefit land requirements.

6.0 RECOMMENDATIONS

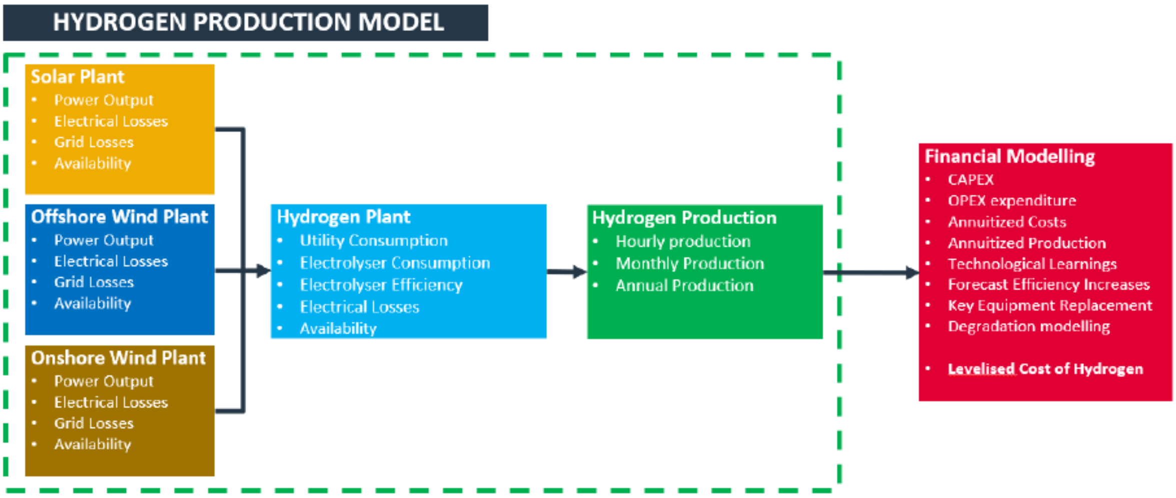
6.1 Recommendations

The following recommendations are for the green hydrogen production at Bacton –Genesis has the capability to perform:

- Understanding the hydrogen market and size of market:
  - Consider hydrogen for mobility and other derivatives of hydrogen in addition to pipeline blending
- Power supply requirements:
  - Renewables mix – significant renewable energy required for 3 x 2.1 GW green hydrogen plants
  - Transmission losses
  - Grid connection requirements (often critical path)
  - Costs of new infrastructure, upgrades and connection (typically significant cost of green hydrogen).
- Vendor and technology selection:
  - See Genesis Report (J75769A-A-TN-00002 B2-Bacton Supply SIG - Green H2 Technology Review) for details on technology and criteria to be considered
  - Compression technology type (recip, axial, centrifugal etc)
  - Electrolyser technology type (PEM, alkaline etc), scaling of stacks/modules/arrays and operating pressure e.g., benefits of high pressure to save on compression duty etc
  - Storage technology type (geological, line pack reusing existing infrastructure etc).
- Cooling study and cooling technology selection:
  - Seawater cooling (and desalination plant) vs air coolers.
- Water feedstock requirements:
  - Connection to local water supply, upgrades and cost
- Effluent and wastewater treatment requirements including disposal routes
- Safety Studies:
  - Flare vs vent requirements for green hydrogen production at scale
  - Safety reviews, HAZIDS etc
  - Emissions & carbon footprint assessments (scope 1, 2 and 3), particularly understanding the CO_2 abated or to be targeted.
- Overall plant optimisation with power sources

  - Holistic modelling of renewable energy and grid connection with hydrogen plant to optimise power, production and storage requirements to minimise life cycle costs and levelised cost of hydrogen and to meet market demands.
  - See figure below for Genesis Green Hydrogen model.
- RAM study to meet export obligations & to determine storage and sparing requirements
- Environmental impact assessments
- Land acquisition, Planning and Consent applications (often critical path activities)
- Detailed layouts including optimisation of equipment and required safety distances
- Synergies between blue and green hydrogen production plants to reduce costs:
  - Including but not limited to utilities, flare, construction, effluent and wastewater treatment
- Offshore green hydrogen production
  - Value to project compared to onshore green hydrogen production
- Learn from other green hydrogen developments at scale and incorporate advancements in technology
  - Safety systems design
  - Technology selection

Figure 6-1 Green Hydrogen Modelling including Renewables – Optmisation of Plant Design & LCOH



7.0 REFERENCES

REFERENCES	
Ref 1	Progressive energy, SNS-Bacton Energy Hub A Vision for the Future Redacted for Commercial Sensitivity, 2021
Ref 2	Position Paper ROTTERDAM HYDROGEN HUB, https://smartport.nl/wp-content/uploads/2019/09/SmartPort-Position-paper-Rotterdam-Hydrogen-Hub-1.pdf
Ref 3	Hydrogen Supply SIG – Project Execution Plan, SUP-PLA-001, Rev 1, March 2022
Ref 4	https://h2tools.org/bestpractices/hydrogen-compared-other-fuels
Ref 5	NASA SAFETY STANDARD FOR HYDROGEN AND HYDROGEN SYSTEMS Guidelines for Hydrogen System Design, Materials Selection, Operations, Storage, and Transportation
Ref 6	https://www.centrica.com/sustainability/net-zero-together/let-s-make-hydrogen-happen/
Ref 7	https://www.eib.org/attachments/pipeline/20100001_nts1_en.pdf

APPENDIX A- GREEN HYDROGEN CTR

CTR Cost, Time, Resource

Project: BEH Supply SIG	Contract No.:	Work Order No.:
Planned Start:	Planned Finish:	Duration:
CTR No.: 002b	Title: Green Hydrogen Production	Date: Rev: By:

Objective:
Review Green Hydrogen Technology availability, scalability and demand requirements
Activity Description:
Review Green Hydrogen technologies. Determine sizing requirements and phasing of different technology solutions and current technology providers. Generate likely development concepts: - Sizing - Phasing Blending requirements Storage Technology availability and anticipated development (upscaling)
Input Requirements:
Demand SIG production requirements (use OOM for early screening) Supplier engagement and data Existing public domain data and studies
Output/Deliverables:
Production facility sizing/scoping Production facility technology readiness report Production profiles for Green Hydrogen, phased
Notes/Assumptions:
Must consider the output and interfaces with CTR’s 002a and 002c
Prepared By:
Name:………………………………………….. Signature:…………………………………..

Date:…………………………………………
Checked By:
Name:………………………………………. Signature:……………………………….. Date:…………………………………………

APPENDIX B – BEH SCENARIOS

Bacton Energy Hub Area Plan Grounding Scenarios

Context

As set out in the Bacton Energy Hub (BEH) vision statement, the overarching goal is to 'Establish a sustainable hydrogen system to ensure Bacton remains a key regional Energy Hub with a low carbon future '. The first stage in doing this is to demonstrate that a credible project exists that presents a value-add opportunity worth the investment to take the hub concept forward to execution.

The objective of this phase of the project and the SIGs is to work towards **building a foundation on which a credible project can emerge**. The basis of this will be the work scopes as set out in each of the SIG TORs. The work scopes will be matured to frame the value proposition and develop a business opportunity document to articulate the potential that the BEH could unlock.

It is recognised that there are a multitude of scenarios that are credible, however detail scenarios will ultimately be required to be explored by the consortium in the future phases of the project. Therefore, maturing an extensive list of scenarios at this stage of the project will add little value when considering the key objective for this phase. It is **NOT** the intention of this phase of the project to define the technical specification or detailed basis of design of the hub. But rather propose a development concept supported by a scoping level design outline to help frame the potential.

The decision has 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 analogous with a P50 development case.

The intent of the scenarios as defined below is to provide a framework to help prioritise work scopes and make best use of available resource and time to complete them to a meaningful conclusion. Also, to concentrate activity on areas which deliver on reducing the key uncertainties around the core case and therefore present a basis for the BEH vision that carries a high confidence supporting the credibility of the project to a future consortium.

Note:

1. There has been discussion on whether an early green hydrogen production scheme could be incorporated in the scenario. To avoid over complicating and distracting from the key objective it has been decided that although this is potential value opportunity it will be considered in parallel rather as a core component to the grounding scenarios.
2. The expectation is that the key information in the table below which details the base assumptions for the scenarios is a first pass and the SIGS will work to validate and refine and or expand the key assumptions as appropriate as the studies and assessment progress.
3. Key Assumptions / Critical Givens below demonstrate some of the potential areas of uncertainty however it will be critical for each SIG to consider the key uncertainties further, that need addressing to inform their prioritisation of work scopes.

North Sea Transition Authority

		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)
	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)
	Maximum Blend %	Assumed 20% blend in 2030 increasing to 100% hydrogen in some parts of region in 2040, all 100% hydrogen in 2050	
	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 (Blue, Green, Blue + Green)	Blue Only*	Blue + Green
	Blue / Green 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)
	Maximum Supply from Blue 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)
	Maximum Supply from Green Hydrogen (TWH / %?)	Zero	0 TWh – 0% of demand (2030) 18 TWh – 46% of demand (2040) 54 TWh – 80% of demand (2050)
	Blue Hydrogen Feedstock Assumptions	Producing and Reserves (Requires approx. 30 mmscf/d). Availability of indigenous supply to be confirmed by SIG	Producing and Reserves + Undeveloped discoveries for Hydrogen with possible import 2040 onwards. Estimated hydrocarbon feedstock: 82 mmscf/d (2030) 356 mmscfd (2040) 274 mmscfd (2050) NB All figures to be verified by SIG, and assessment of indigenous vs imported supply
	Green Hydrogen Feedstock Assumptions	N/A	Dedicated wind/solar plus connection to (green) grid (2050)
	Export Yes / No?	No	No
	CS Yes / No?	Yes	Yes
	Hydrogen Storage Yes / No?	No	Yes
	Land requirement	Within existing plant	Blue hydrogen within existing plant boundary with potential re-use of

GENESIS