Phase 1 Project Report

Delivery of an offshore hydrogen supply programme via industrial trials at the Flotta Terminal

HOP Project – HS413

The Oil & Gas Technology Centre
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1. Executive Summary

The UK in line with the International Energy Agency (IEA) has stated that we need to move faster to achieve the desired level of integration for a hydrogen-based economy. According to the IEA today's Hydrogen is almost entirely supplied from natural gas and coal across the globe. However, its production is responsible for annual CO_2 emissions equivalent to those of Indonesia and the United Kingdom combined. To achieve the increase in production we need to address these disadvantages in situ by capturing emissions and storing in close proximity to where we produce them or by seeking cleaner energy supplies.

Our project proposes to reuse existing infrastructure as much as possible to minimize environmental impact and gain a time advantage for deployment of Hydrogen production equipment at scale. The Hydrogen Hub Orkney will allow Hydrogen production equipment to be installed, tested and then redeployed offshore on demonstrator projects in the shortest possible time frame. This will position the UK as market leader in the development of Hydrogen production technology for use in the offshore marine environment utilising our existing Oil and Gas infrastructure for lower-cost, lower-carbon hydrogen.

The project yielded the following key conclusions:

- **Market for Offshore Hydrogen:** Addressing future energy requirements will be challenging and the UK should make the most of all available infrastructure. Considerable opportunity exists to re-purpose offshore assets for hydrogen service upon cessation of production of oil and / or gas.
- **Hydrogen Production Technologies:** Four technologies have been identified as suitable for hydrogen production offshore. Those are Steam Methane Reforming with Carbon Capture and Storage, Gas to Graphene technology, PEM electrolysis and Alkaline Electrolysis. Common to all is the need for further containerisation and certification for unmanned offshore deployment.
- **Scenarios for Offshore Hydrogen:** Utilisation of offshore assets has resulted in four scenarios being identified for hydrogen production. These include full re-purposing of asset topsides (large and small), retrofitting to operational assets and harnessing wind and wave resources for electrolysis. A large offshore asset completely re-purposed for hydrogen could produce circa 20,000kg per day of hydrogen.
- **Pipeline Re-Use for Hydrogen Service:** The Phase 1 project suggests that approximately 30% of the existing pipelines could be repurposed for the transportation of hydrogen. The initial study also found that a small subset of the pipelines could be used to transport CO_2. Both of these findings require further work.
- **Financial Analysis for HOP:** Deferment in decommissioning cost provides an attractive mechanism to support the financial case for offshore hydrogen production. Hydrogen production using the G2G process produces the lowest LCOH for offshore application. There is additional opportunity to reduce the LCOH for offshore by circa 25% through learning by doing.
- **Hydrogen Hub Orkney:** The cost for construction of the H^2O will be circa £6.3m. The H^2O is expected to be operational in 2021 and could be profitable within one year of operation. It will support the development of all hydrogen technologies, in addition to those specifically identified in this project.

Re-use of offshore infrastructure generates several commercial opportunities to both produce hydrogen at scale and potentially at lower cost. Part of the cost saving includes extension of asset life, deferment of decommissioning costs and the provision a low cost, medium volume hydrogen storage mechanism.

The HOP project demonstrates that there is a viable pathway to produce hydrogen at scale, utilising existing offshore infrastructure at a cost competitive with existing technologies. This can be done without the need for the additional investment required for CO_2 transportation and sequestration.

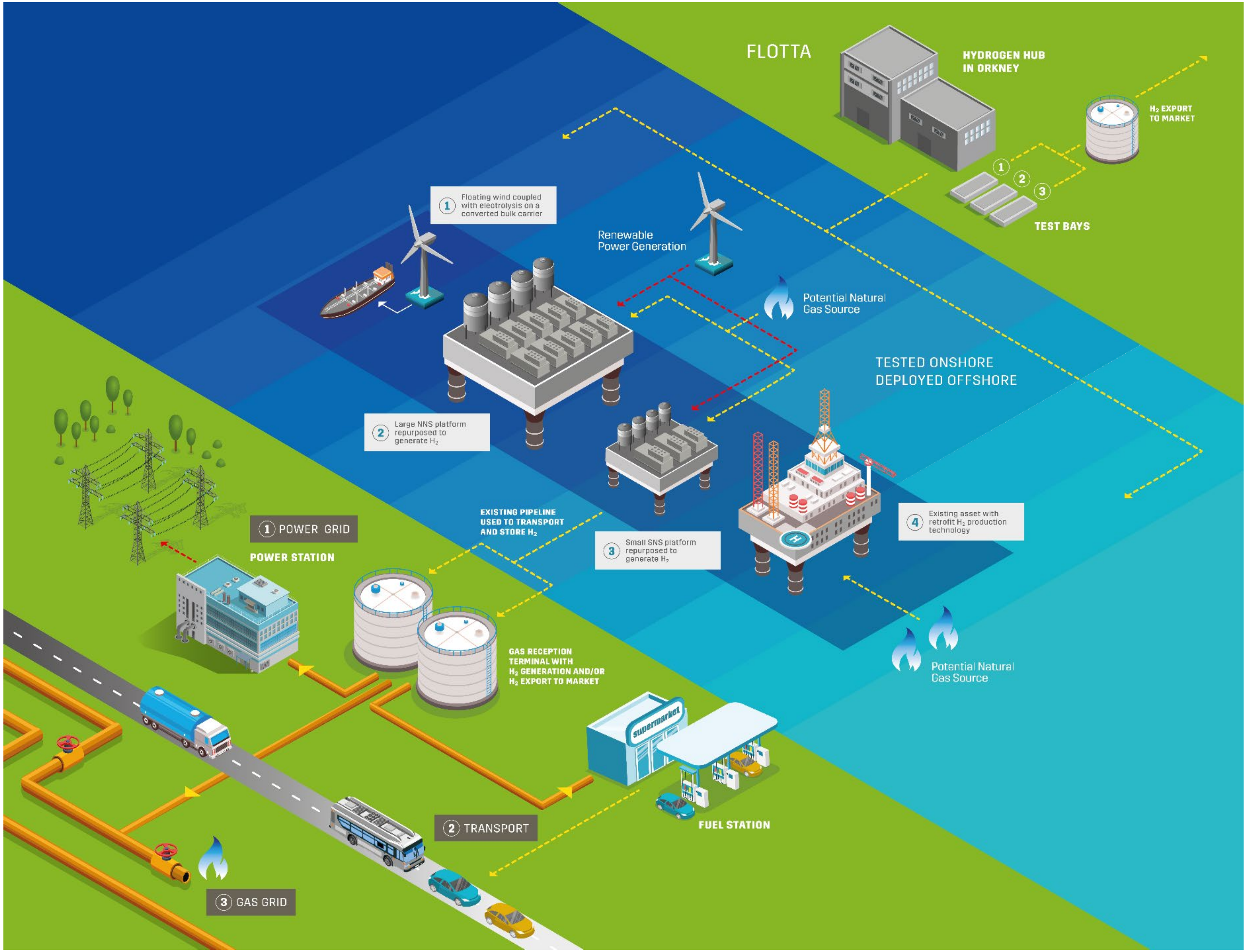

Figure 1 – HOP Scope Diagram

2. Introduction

2.1 Background

The UK and the international community are committed to realise the benefits of a hydrogen-based energy economy; the Hydrogen Council estimate the market for hydrogen and hydrogen technologies will reach revenues of more than $2.5 trillion per year and create jobs for more than 30 million people by 2050 [1].

Given the stated climate emergency, the emerging technologies for producing hydrogen are increasingly focused on becoming carbon-neutral and potentially carbon negative. To create a hydrogen-based economy and move towards an energy system based on clean technologies, bulk hydrogen production is required.

Recognising this need and as part of the BEIS Hydrogen Supply Programme the project partners of Aquatera, Cranfield University, Doosan Babcock, European Marine Energy Centre (EMEC), National Oilwell Varco (NOV) and The Oil and Gas Technology Centre (OGTC) have delivered a project titled "Delivery of an offshore hydrogen supply programme via industrial trials at the Flotta Terminal" or the Hydrogen Offshore Production (HOP) project. The project will address the opportunity of offshore hydrogen production by re-using existing oil & gas infrastructure across the United Kingdom Continental Shelf (UKCS).

The UK has over 250 platforms and 45,000 kilometers of pipeline installed within the UKCS. As these assets near the end of their economic life oil and gas operators are planning to decommission these facilities in an efficient and cost-effective manner. Current cost forecasts for this activity exceed £56bn [2] with approximately 50% borne by the operators and 50% borne by UK taxpayers.

This project will prove the feasibility of several decentralised hydrogen generation, storage and distribution options that collectively provide a scalable offshore hydrogen production solution. HOP identifies an alternative by providing re-use options for offshore infrastructure while addressing the national challenge of a low carbon energy supply.

2.2 Project Overview

The HOP project will tackle the challenge of bulk hydrogen production by:

1. Proposing viable environmental and economic technology solutions
2. Developing a new Industrial Hydrogen Production test facility (Hydrogen Hub Orkney (H^2O)) to both prove the industrial benefits and to aid commercialisation of emerging technology
3. Producing the business case for transformation of the existing offshore infrastructure, re-purposing assets and demonstrating the viability for decentralised generation of hydrogen

This will enable bulk hydrogen production using decentralised offshore platforms and infrastructure, offsetting a portion of forecast decommissioning costs that are currently estimated for all offshore assets and infrastructure.

To meet the project objectives, the scope was fundamentally delivered across three areas; Technology Analysis, Market Analysis and Flotta Test Site Development. Each activity area will be discussed further in this document.

2.3 Objective of Document

The objective of this document is to summarise the work completed as part of the "Delivery of an offshore hydrogen supply programme via industrial trials at the Flotta Terminal" (the HOP project).

The summary document will outline the key findings from each activity undertaken as part of this project, providing conclusions and recommendations for further development in order to facilitate an offshore hydrogen production solution. A flowchart to depict the key activities is shown in Figure 2.

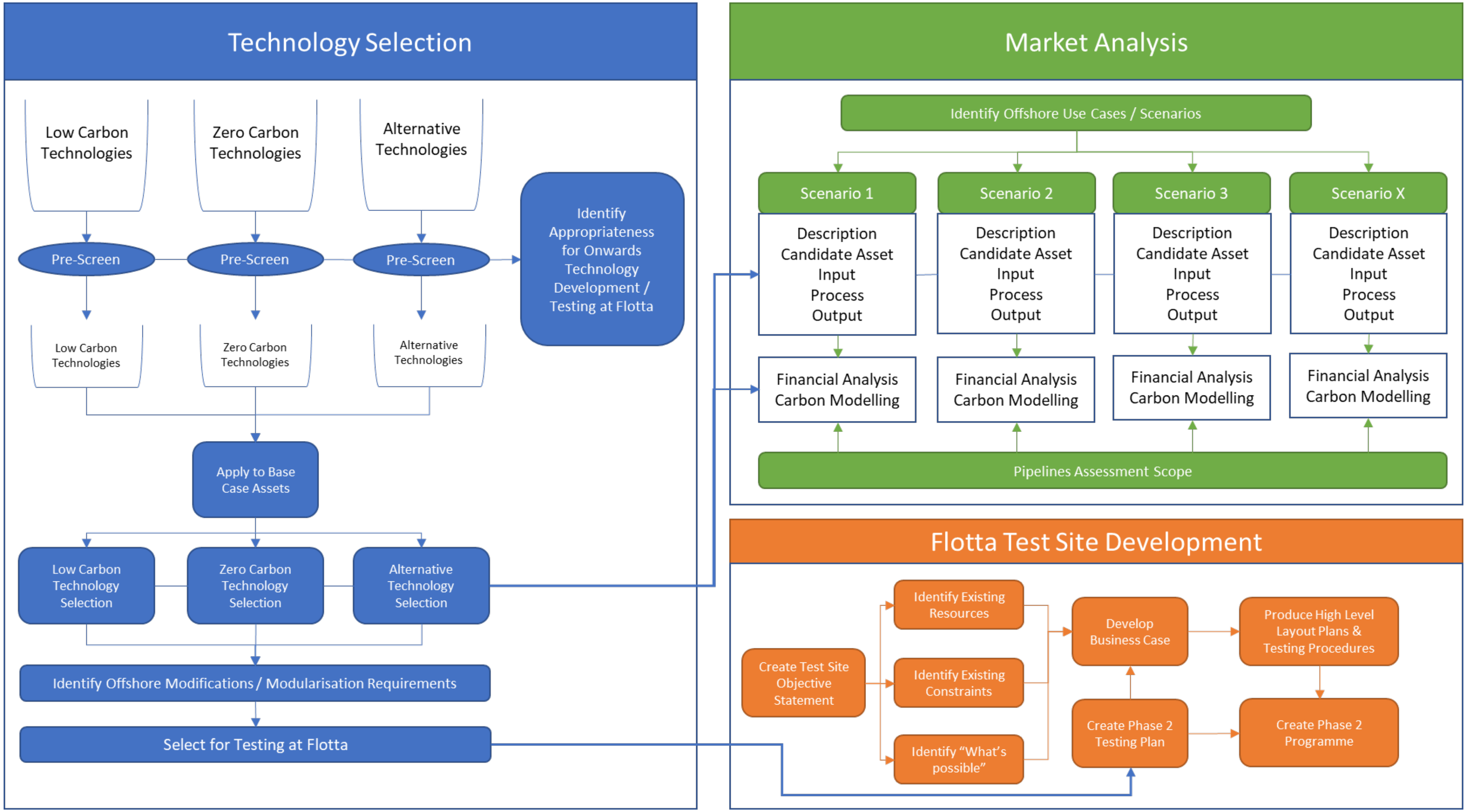

Figure 2 – HOP Project Scope Summary

3. Market Analysis

3.1 Industrial Change & Decarbonisation

The UK has recently committed to achieving net zero carbon emissions by 2050 following recommendations by the Committee on Climate Change [3]. This commitment means that we need to find solutions to decarbonise our current energy system. There are several proposed pathways to achieve this, but the dominant pathways include electrification of our energy system and the development of a hydrogen economy.

Low carbon hydrogen, and the development of a hydrogen economy, is attractive for a number of reasons and could play a key role in decarbonising the UKs power, heat and transport systems. To achieve our net zero targets, a large amount of renewable resources will be required within the UK grid. However, technologies such as wind and solar power are intermittent and need to be coupled with storage solutions to provide adequate baseload and respond to daily and seasonal fluctuations in energy demand. Hydrogen could provide a storage solution for renewable energy technologies to become a reliable baseload energy vector through electrolysis coupled with storage.

Additionally, hydrogen produced from large industrial processes such as steam methane reforming (SMR) coupled with carbon capture and storage (CCS) could provide bulk low carbon hydrogen for blending or pure service through the National Gas Grid. Despite this requirement, there is still not a consensus on how we best support the UKs transition to a net zero future.

Greater confidence in the ability to produce bulk low carbon hydrogen is required, at a cost which is more acceptable and / or comparable to current systems. Policy change, legislation and regulation to support this change / transition is also required to support a transition driven by the energy industry and supply chain.

If this can be achieved, there is significant opportunity for the UK supply chain to build new skills, transition currently skilled workers and create a new export market for the country.

3.2 Hydrogen End Users

Low carbon hydrogen could play an important role in decarbonising the power, heat and transport requirements for the UK. Figure 3 to the right shows the breakdown of energy use in these areas [4]; although heat is the dominant energy usage area, it is clear that any hydrogen solution must have the flexibility to supply energy across all these energy usage areas.

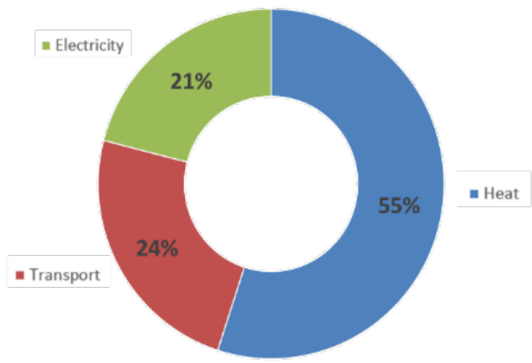

Figure 3 – Breakdown of Energy Use in UK

The hydrogen economy is still emerging and there is not currently large scale demand for hydrogen in the UK. However, there are a number of projects ongoing to prove hydrogen concepts with the aspiration of accelerating the acceptance of the hydrogen economy.

For the market to grow, the supply chain needs confidence in security of supply at a sustainable price point.

Hydrogen for Heat

The national transmission system in the UK (national gas grid) comprises of over 4,700 km of high pressure gas pipelines [5]. At present, the natural gas distributed within these pipelines is the primary source of heat for the country. Given heat is the predominant energy usage area, it is important that we find a decarbonisation solution. There is an opportunity to use hydrogen gas as an alternative low carbon gas for heating.

Trials have shown that hydrogen can readily be injected into existing onshore natural gas pipelines without any requirement for pipeline modifications, providing a stepping stone to a full hydrogen heat system. With up to 20% of hydrogen content, the mixture can also be burned in conventional boilers and gas cookers without modification [6].

Hydrogen for Power

Excess electricity, such as that generated by renewable devices, can be used to produce hydrogen via an electrolyser and the hydrogen can then be used to power a hydrogen fuel cell. The efficiency of this process is significantly less than using electricity to charge a battery for energy use, so the market application may seem limited.

There are, however, applications where batteries are not the best solution and hydrogen can fill the void. For example, it could be possible to use this technology to supply power for hydrocarbon extraction for subsea oil & gas fields. Specifically, smaller reservoirs where a fuel cell could be used as an alternative to a traditional umbilical that supplies power from a host. With over 363 small pools within the UKCS, this could represent a significant opportunity for hydrogen with an electrical power application.

Hydrogen for Transport

The net zero target also requires the transport industry to move to alternative fuels. Hydrogen fuel cells are a proven technology for trains, buses and cars. In terms of vehicles a recent scenario put forward by the IEA suggests that 30% of vehicles could be fueled by hydrogen by 2050 [7]. Commercial vehicles and buses are subject to pilot projects and the technology is rapidly growing with significant future potential.

The use of hydrogen to power ferries is at an early stage. The UK's first hydrogen powered passenger ferry is to be built in Scotland by 2021 under the HySEAS III project. The initial objective of the project is to construct and test parts of the vessel for stress and durability in real-world conditions. If that proves successful, then the ferry will be constructed with a view to operate in and around Orkney – where green hydrogen is already being produced due to both the Surf n' Turf and BIG HIT project.

3.2 Offshore Market for Hydrogen

As global energy companies seek to address an increasing energy demand with low carbon solutions, they are now looking to alternative energy sources.

In addition, the offshore sector is looking to decarbonise their existing operations, as well as considering cleaner ways to extract remaining oil & gas reserves across the UKCS. The OGTC have worked with industry to develop the following roadmap for decarbonised offshore operations and driving towards a net zero basin:

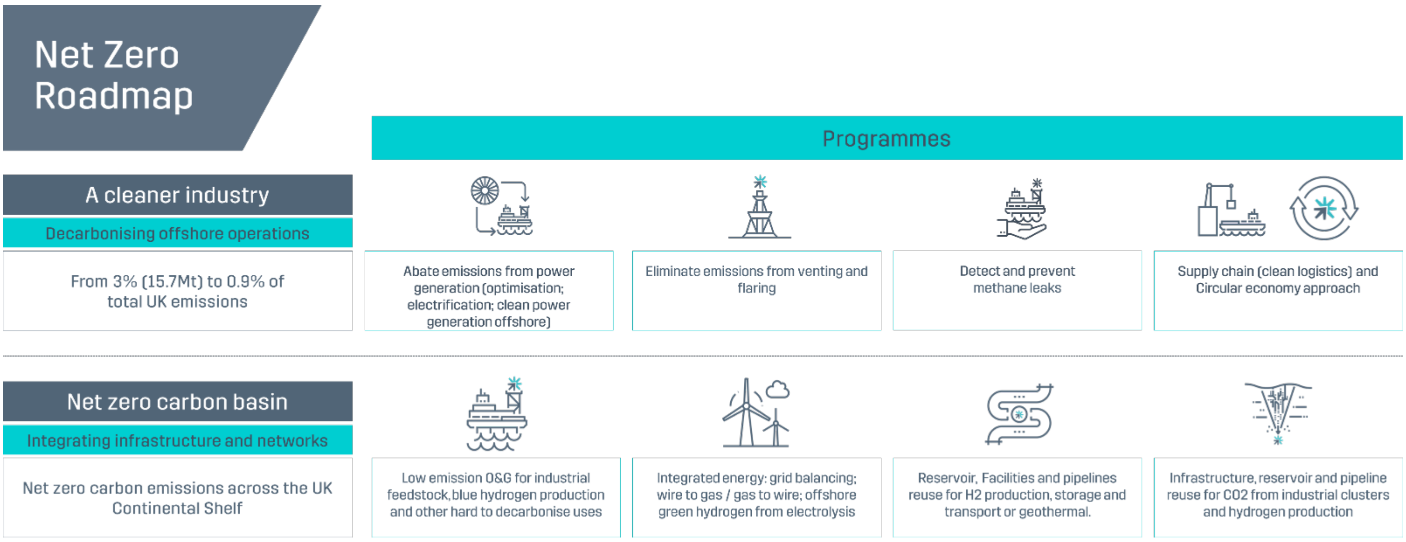

Figure 4 – Net Zero Solution Centre Roadmap

An area of opportunity that has emerged across the sector is the re-use or re-purposing of offshore assets as alternative energy production systems. The extensive infrastructure in the North Sea would otherwise be decommissioned with considerable expense to the UK government, taxpayers and private organisations. The opportunity to re-purpose assets, as well as additional opportunities for hydrogen offshore are discussed below.

Opportunities for Re-Use & Re-Purpose

With over 250 oil & gas platforms and 45,000 km of pipelines installed in the North Sea, there are considerable opportunities to use the existing infrastructure and take advantage of already sunk investment. This would create a new business stream for operators, building an alternative energy supply chain and defer decommissioning costs, whilst the industry works to reduce the overall decommissioning spend. Current cost forecasts for this decommissioning activity exceed £56bn [2].

Decommissioning regulation at a national level has to conform to the Oslo and Paris Convention regulations (OSPAR 98/3, 1998), which requires all redundant man-made structures within the OSPAR region to be removed for disposal on land. The only exception to this rule is concrete gravity structures, the footings of Steel Piled Jackets that were installed before 1999 and where the jacket exceeds 10,000 Te in weight. Meantime, the original asset owners are liable for the integrity of the reservoirs in perpetuity.

When considering an alternative energy mix for the future, it is imperative we consider all the assets to ensure we are maximising our resources, and this should include an assessment of alternative offshore infrastructure uses. Other countries with similar infrastructure are following a comparable pathway. Neptune Energy recently announced a pilot project for the first offshore hydrogen plant in the Dutch sector. A megawatt electrolyser will be placed within a sea container and installed on Neptune's Q13a platform, located near the Dutch coast, 13 kilometers from Scheveningen [8].

There have been no technology barriers identified for producing hydrogen offshore. Hydrogen production technologies are generally well proven, and the oil & gas industry has extensive experience operating with volatile gases.

A key challenge for the offshore industry is the business case surrounding hydrogen production offshore. This is discussed further in section 7 of this document. Work during the project and by others has highlighted this as an area for further development. A report produced by Highland Potential for the OGTC [9], provides for hydrogen production costs estimated in 2019 as shown in Figure 5.

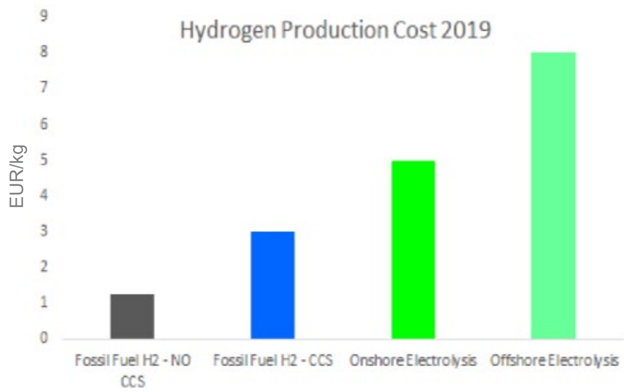

Figure 5 – Hydrogen Production Costs 2019

A study by DNV [10] considered the production of hydrogen by SMR with CCS onshore versus offshore for the Dutch sector. The study identified that the cost crossover point for onshore versus offshore was at 295km from shore. This indicates there are potential cost benefits of hydrogen production offshore, with CCS sites nearby.

Additional Offshore Opportunities

Potential opportunities for hydrogen and general energy integration offshore is gaining industry momentum. Although the scope of this project is the re-use and re-purposing of assets and pipelines; there are a number of other projects being developed which add breadth to the offshore hydrogen market:

Downhole Hydrogen	Floating Wind Electrolysis
Emerging concepts for downhole hydrogen include coal gasification and downhole conversion of methane to hydrogen directly by oxygen injection. In both cases, carbon is kept downhole negating the need for carbon capture and storage.	Taking advantage of the extensive offshore wind resource, there are several concepts emerging with electrolysis coupled to floating wind. These include ERM Dolphyn and TechnipFMC Deep Purple concepts.
Subsea Hydrogen	**Offshore Power Islands**
Subsea hydrogen production is an attractive, cost-effective prospect to power UKCS small fields. Work completed by CRM Protech in collaboration with Shell and Equinor developed a 32MW subsea concept.	There are existing concepts that consider the production of energy facilitated by an Offshore Power Island. Surrounded by wind turbines, hydrogen is produced by electrolysis and sent to shore through pipelines.

4. Technology Selection for Offshore

Having established the potential hydrogen offshore market, a key objective of the HOP project was to propose viable environmental and economic technology solutions. This section of the document describes this process.

4.1 Best Available Technology Review

Following a technology identification exercise, a qualitative assessment was carried out utilising information gathered from academic and industrial literature as well as equipment supplier information.

The aim of the qualitative assessment was to understand the current status of technology development, the commercially available sizes, and required feedstocks, power, utilities, and waste streams. These areas were used to determine whether the technology is ready for large scale deployment offshore in the near-term, whether the technologies have access to the required feedstock's and utilities offshore, and whether appropriate waste management systems can be implemented.

The following technologies were identified as suitable for use offshore:

1. Steam Methane Reforming with Carbon Capture and Storage (SMR with CCS)
2. Gas-to-Graphene (G2G)
3. Proton Exchange Membrane (PEM) Electrolyser
4. Alkaline Electrolyser

4.2 Technology Descriptions

Steam Methane Reforming

Steam methane reforming (SMR) is a chemical process that produces hydrogen from methane and water. The technology has historically been the most commonly used method of hydrogen production and has traditionally been favoured for large-scale production, utilising natural gas or refinery off-gases as the feedstock. The principle reaction leads to the creation of syngas, whilst additional hydrogen can also be produced via the water-gas shift reaction.

Containerised SMRs are commercially available, such as the PRISM Hydrogen Generator (PHG) produced by Air Products. The PHG is a scalable system that can be tailored to meet specific process requirements. The PHG has a modular, packaged plant design that allows for easy in-field installation and fast start-up, and they can be controlled remotely. The PHG-250 unit producing 250 Nm^3/hr H_2 and contained within a single 40 ft shipping container can be seen in Figure 6, right.

Figure 6 – PHG-250 Containerised Unit

Gas to Graphene

Gas to Graphene technology, currently developed by Cambridge Nanosystems uses a microwave plasma reactor to break down methane gas into hydrogen and elemental carbon atoms. The atoms are recombined into graphene sheets by floating them in the hydrogen atmosphere. The output from the plasma reactor is a mixed stream composed of hydrogen gas, acetylene gas, methane gas, and graphene. This process is illustrated in Figure 7.

Filtration is required to separate and recycle the methane, and to separate the acetylene, hydrogen, and graphene, each of which are valuable products and can be sold individually into various markets. The ratio of hydrogen to graphene produced by mass has a ratio of approximately 1:2.

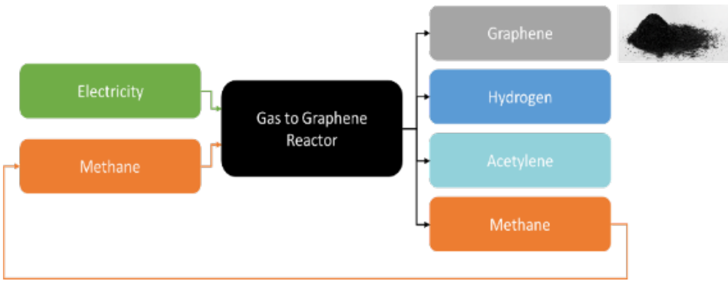

Figure 7 – Gas to Graphene Process

As well as acting as a secure capture process for the carbon, the graphene is a highly valuable commodity. It has applications in technology, materials, manufacturing, and electronics sectors. The high consumption of both electricity and methane as feedstock results in low energy efficiency when considering energy input versus hydrogen output. However, the additional products created during the process make the technology attractive. At present the technology has been in operation at pilot scale, with modular containerised systems currently being designed, aimed at offshore environments.

PEM Electrolyser

In a Proton Exchange Membranes (PEM) unit a semi-permeable membrane allows the passage of protons while acting as an electronic insulator and chemical barrier between the two reactions' regions. The membrane can be made from either pure polymer membranes or from composite membranes, in which other materials are embedded in a polymer matrix. PEMs are robust, and offer safe, simple operation; they are also well able to cope with variations in power supply that may be expected to arise as a result of the use of renewable (primarily wind) resources for the electrical supply.

Hydrogen and oxygen are produced separately, so there is no further separation step, although a gas purification unit and a compressor are included, allowing units to deliver high purity (> 99.9 %) hydrogen at around 30 bar (depending on specification). Two suppliers of modularised, containerised PEM units, Areva and Nel-Hydrogen have been identified. The NEL MC400 is contained within two 40 ft shipping containers, and delivers 400 Nm^3/hr H_2, whilst the Areva E120 is contained within a single 40 ft shipping container and delivers 120 Nm^3/hr H_2.

Alkaline Electrolyser

Alkaline electrolysers utilise a liquid alkaline electrolyte solution, typically of potassium hydroxide (KOH). The electrodes are separated by a diaphragm, separating the product gases and transporting the hydroxide ions (OH^-) from one electrode to the other. The electrolyser requires constant potential difference, and so is less able to deal with a fluctuating power supply resulting from renewable sources such as wind.

Alkaline electrolysers are available in modular, containerised format, and are typically around 30% cheaper than PEMs for units of a similar capacity. The use of alkaline electrolysers has been discussed with one supplier, Nel-Hydrogen: their AC300 unit is contained within a single 40 ft container.

4.3 Technology Selection Process

From the short-listed technologies described above, quantitative analysis was undertaken to determine the best performing technologies from a number of key performance indicators. For each of the technologies a commercially available, modular unit was selected. Equipment datasheets and cost information was supplied by the technology vendors. This is shown in the table below:

	SMR	Gas-to-Graphene	PEM Electrolyser	Alkaline Electrolyser
Quantity of Hydrogen (kg / unit / day)	540	576	893	648
Hydrogen Quality (%)	Up to 97.5	Up to 70	99.999	Up to 99.5
CAPEX ***(£ / MW H_2)***	1.91	1.25	1.94	1.33
Equipment Area ***(m^2 / MW H_2)***	191	37	61	97
Equipment Weight ***(kg / MW H_2)***	50	13	15	21
Carbon Dioxide Emissions ***(kg / MW H_2)***	295	2	0	0
Natural Gas Consumption ***(MWh / MWh H_2)***	1.50	1.25	0.00	0.00
Electricity Consumption ***(MWh / MWh H_2)***	0.05	0.30	1.51	1.37
Hydrogen Production Efficiency	65%	30%	66%	73%
Water Consumption (litres / MW H_2)	907	0	301	300

To identify those best suited to offshore and select the final technologies for testing at Flotta, a linear scoring scale was applied to the technologies and a weighting was applied to a number of the criteria shown on the previous page. The weighting assigned to each performance metric is given in Figure 8.

Based on this evaluation, it is recommended that the following technologies are considered for testing at the Flotta facility:

Performance Metric	Weighting
CAPEX ***(£ / MW H_2)***	20%
Equipment Area ***(m^2 / MW H_2)***	15%
Equipment Weight ***(kg / MW H_2)***	5%
Carbon Dioxide Emissions ***(kg / MW H_2)***	15%
Natural Gas Consumption ***(MWh / MWh H_2)***	10%
Electricity Consumption ***(MWh / MWh H_2)***	10%
Hydrogen Production Efficiency	20%
Water Consumption ***(litres / MW H_2)***	5%

Figure 8 – Weightings Applied to Performance Metrics

1. Alkaline electrolyser (requires electricity and water as feedstock)
2. PEM electrolyser (requires electricity and water as feedstock)
3. Gas to Graphene (requires gas and electricity as feedstock)
4. Steam Methane Reformer (requires gas and water as feedstock)

Testing for Deployment Offshore

A number of the technologies identified above are commercially available in a containerised form. However, common to all is the immaturity of hydrogen systems and associated infrastructure for offshore deployment. Suitable technologies will require additional testing and certification for operation in the offshore environment, see section 8 for a description of the proposed test facility at Flotta.

4.4 Replicability for Scale

It is expected that all the UKCS regions will have viable hydrogen production, storage and transport solutions. To demonstrate a case study offshore, it is necessary to establish a design envelope and basis. This will allow for comparison with the counterfactual production rate provided by BEIS as part of the Hydrogen Supply Programme and provide a basis for understanding the number of offshore assets required to meet the counterfactual.

Two basin areas have been selected, which represent the larger footprint (Northern North Sea) and smaller footprint (Southern North Sea) assets within the UKCS. These areas cover a large portion of the UKCS and are therefore representative of most assets offshore. Traffic light systems in Figure 9 have been used to show the availability of resources generally in that area (Note: assets are representative only). See Figure 9 below:

Northern North Sea Asset

Production Type	Topsides Weight	Similar to:	Natural Gas Availability	Renewable Resource
Oil and Gas	28,000Te	Brae Alpha Ninian North		
Water Depth	Topsides Deck Dimensions	Dunlin Alpha	Gas Export?	Retrofit Footprint
150m	70 x 40m 3 Decks	Miller Brent Delta		

Southern North Sea Asset

Production Type	Topsides Weight	Similar to:	Natural Gas Availability	Renewable Resource
Gas	1,400Te	Ketch Markham		
Water Depth	Topsides Deck Dimensions	Viking BA	Gas Export?	Retrofit Footprint
30m	25 x 20m 3 Decks	Viking BP Camelot		

Figure 9 – Design Envelopes for Typical North Sea Assets in the Northern North and Southern North Sea

Offshore Platform Plans

From here, indicative layout drawings have been produced for selected technologies, based on information provided for two potential platforms: Markham (22 m x 26 m) and Brent Delta (72 m x 47 m). In these drawings, maximum modularisation has been assumed, i.e. each hydrogen production unit is connected to an individual desalination plant, and gas compression and storage system.

Layout Drawings have been completed for the following and can be found in Appendix A:

1. Markham asset with PEM Electrolysers and SMR System
2. Brent Delta with SMR System

Note that these drawings are purely indicative and based on publicly available information regarding asset footprints. A number of assumptions have been made for each layout case e.g. a nominal storage capacity has been included since storage capacity offshore has not yet been defined.

Based on the Markham and Brent Delta assets, considering space on one deck only, the layout drawings show these assets would have the potential to produce the quantities of hydrogen shown in the table below. The table below is an outline of the number of platforms that would be required to produce hydrogen at the same rate as a typical onshore steam methane reforming plant (BEIS counterfactual):

		Markham	Brent Delta
PEM Electrolysers	No per Asset	4	22
	Kg H_2 / Asset / Day	3,568	19,626
	MWth	5.0	27.3
	No of Assets to Meet BEIS Counterfactual	61	11
	Capital cost of equipment to meet BEIS Counterfactual	£586M	£581M
SMR	No per Asset	4	22
	Kg H_2 / Asset / Day	2,160	11,880
	MWth	3.0	16.5
	No of Assets to Meet BEIS Counterfactual	100	18
	Capital cost of equipment to meet BEIS Counterfactual	£860M*	£774M*
Gas to Graphene	No per Asset	4	22
	Kg H_2 / Asset / Day	2,304	12,672
	MWth	3.2	17.6
	No of Assets to Meet BEIS Counterfactual	94	17
	Capital cost of equipment to meet BEIS Counterfactual	£376M	£374M

With over 250 assets in the North Sea, replication has the potential to reach the bulk hydrogen production scale provided for in the counterfactual. Initial offshore production is likely to be through retrofit followed by a full topside re-purpose. Replication across a number of assets also provides opportunities to lower the costs of installation through learning by doing. Learning by doing is discussed further in section 7.

** - costs for SMR include capital costs associated with carbon capture and storage.*

5. Offshore Pipeline Assessment

With 45,000 km of pipeline installed in the North Sea, there is considerable opportunity to take advantage of this infrastructure and consider this pipeline system for re-purposing. Within the scope of this project, re-purposing of the pipeline infrastructure for a hydrogen service (transport and storage) is considered and how this would fit with a future energy industry that also requires carbon capture and storage. The potential to use the pipelines as a storage medium has also been considered as this would provide considerable storage to meet variable demand.

5.1 Existing Pipeline Material Compatibility

Oil and gas pipelines have been converted to hydrogen service before (the Dutch national gas company Gasunie converted a 12km idle natural gas pipeline to transport hydrogen in 2018), and the conversion of subsea pipelines is possible if the pipeline meets the material and dimensional requirements for safe operation. Not all pipelines will meet these requirements, and integrity assessments to identify challenges, such as corrosion, will be required.

The material of choice for offshore oil and gas pipelines is carbon steel due to its relatively low cost, good availability, good mechanical properties and ease of fabrication. Most of the existing offshore pipelines in the North Sea are made of carbon steel; stainless steel is typically specified for short length infield flowlines.

Offshore carbon steel pipelines are constructed of different material grades, with the variations mainly reflecting the design codes, operating pressures and age of the pipelines. The suitability of carbon steel pipelines for transporting hydrogen gas or mixtures is dependent on a number of embrittlement and degradation mechanisms, which are attributed to hydrogen.

The materials study highlighted the following interactions and restrictions imposed by a hydrogen service:

- Hydrogen service causes embrittlement of materials: a reduction in yield strength and fracture toughness and an increased crack growth rate, leading to reduced fatigue life
- Hydrogen embrittlement is dependent on operating conditions and material properties and has a greater effect on steels with higher tensile strength
- Hydrogen blistering, sulphide stress cracking and hydrogen induced cracking are possible where hydrogen is blended with sour natural gas. However, for pure hydrogen service this is not applicable
- The hydrogen maximum operating pressure should be defined so that the maximum stress in the pipeline walls is below 30-50% of the minimum specified yield strength
- The recommended pipeline material grades for hydrogen service are API X42 and X52. Grades above X52 are more likely to be severely affected by hydrogen embrittlement
- The limitations of stress and material grade equates to approximately 50 – 150bar maximum pressures for typical sizes of X52 pipelines which appears feasible for hydrogen storage and transportation

Detailed data on material specifications or operating pressures and temperatures of the existing subsea oil and gas pipelines across the UKCS is not readily available and therefore detailed calculations for the entire pipe network has not been possible.

It is however more likely for older pipelines to be of a lower material grade (X42 or X52). Pipelines installed in the 1990s were identified as optimum as they are likely to still have acceptable mechanical integrity and a lower yield strength.

For pipelines that are considered incompatible with hydrogen service due to material compatibility, novel technologies such as polymer liners were explored to overcome material challenges. Polymer liners are currently installed in subsea pipelines; however, they are technically challenging. Advancements in technology in this area would be required to ensure compatibility with hydrogen service.

Carbon Dioxide Service

Assuming that a low carbon energy mix would require some level of CCS, re-use of pipelines for CO_2 has also been considered. Corrosion rates in a pipeline where water is in contact with pure CO_2 are expected to be relatively high, certainly enough to rule out the use of carbon steel in most cases. Sufficient drying upstream of the pipeline is required to prevent excessive corrosion rates.

Following capture, it is therefore assumed that the CO_2 will be treated to near 100% purity. If this is the case, corrosion is not a major issue for transport of CO_2 streams, and carbon steel is a suitable material for CCS. Case studies within the USA and Norway of CO_2 transport in carbon steel pipelines have not reported any issues with compatibility and in particular corrosion with a dry service.

5.2 Conversion of Existing Assets

A material compatibility map of the UK pipeline infrastructure has been prepared and is included in Appendix B. This shows pipelines which are ranked into suitability categories. The ranking criteria is based on:

- **Fluid currently transported in the pipeline.** Pipelines that are currently used to transport natural gas are most likely to be suited to hydrogen. This is because water pipelines are most likely to have suffered from internal corrosion metal loss, and crude oil pipelines would have to undergo heavy cleaning to remove traces of hydrocarbons and other impurities.
- **Pipeline age.** Pipeline material grades X42 and X52 are recommended by the American Society of Mechanical Engineers (ASME) for hydrogen use. There is no publicly available data on pipeline grades, but the trend in recent years has been towards higher material grades. Hence, older pipelines are more likely to be made of suitable grades of steel. Based on experience, pipelines built between 1980-2000 are more likely to be a suitable material grade.

Unfortunately, the National Data Repository (a data service managed by the Oil and Gas Authority) does not contain the material grades for the UKCS pipelines at the moment and therefore it has not been possible to specify the exact pipelines that are most suitable for Hydrogen service. Based on industry knowledge and previous projects, the assumptions made to construct the map have been shown to be correct. Xodus reviewed a sample of pipelines within the southern North Sea and found that 22 of 53 gas pipelines, roughly 40%, would be suitable for hydrogen.

Pipelines for Storage

Assuming 40% of pipelines are suitable for re-purposing for hydrogen service is generally representative of the North Sea as a whole and removing an additional 10% for integrity challenges then 30% of pipelines across the North Sea could be deemed acceptable for hydrogen service. This would relate to 13,500 km of pipelines. On a highly conservative basis, assuming all of these suitable pipelines are 10inch diameter, operating at 40bar pressure and 10°C with a closed in system, 2,366,550 kg (2,367 Te) of hydrogen could be stored in the pipelines. Dynamic simulations are required to understand the operational challenges and will be addressed in Phase 2 of the project.

5.3 HSE Considerations

When considering re-purposing of pipeline infrastructure, a comprehensive portfolio of the pipeline condition should be compiled and assessed for suitability for the proposed service. This portfolio should include the design code, material, fluid transported, age, inspection and repair history, and current condition of the pipeline. If the pipeline has previously been in anything other than clean dry gas service, an internal inspection and comprehensive internal cleaning should be completed.

In the context of extending the life of the existing infrastructure, this will see existing infrastructure remain in place for an extended period of time. Leaving solid infrastructure in situ for an extended period of time, or possibly in perpetuity if infrastructure can no longer be removed, is not as problematic for habitats in the West of Shetland region as the seabed is generally a hard substrate and the infrastructure does not present a new substrate form. However, infrastructure left in situ in natural, soft sediment habitats presents an alien substrate which could affect species composition.

For spill / leak risks, both hydrogen and CO_2 will either dissolve rapidly without detection in deeper waters, or break through to the surface in shallower waters, where it will rapidly disperse. This is likely to be the case regardless of whether a release occurs during transport, during CO_2 injection or once in storage in the reservoir.

6. Scenarios for Hydrogen Offshore

With hydrogen production technologies suitable for the offshore environment identified, base case assets created, and pipeline suitability established, scenarios are required to translate each of these stand alone areas into feasible concepts.

The scenarios described in this section translate the most promising hydrogen technology solutions into design cases. This then supports the development of financial analysis for each design scenario. They exploit the areas of opportunity for offshore hydrogen production including the potential utilisation of renewable resources and the repurposing of existing offshore oil and gas infrastructure.

6.1 Scenario Descriptions

The following scenarios were identified as being most promising in the course of this feasibility study:

- **Scenario 1:** Access to the most abundant UK renewable energy resources that lie to the north of the Scottish mainland. Floating wind and electrolysis used to generate hydrogen, which is exported via a hydrogen pipeline to Shetland where it can be stored and exported further by ship.
- **Scenario 2:** The repurposing of large offshore assets with SMR, electrolysis or graphene. This scenario is primarily focused on Northern North Sea assets e.g. the Brent field.
- **Scenario 3:** The repurposing of small offshore assets with SMR, electrolysis or graphene. This scenario is primarily focused on Southern North Sea assets e.g. the Markham field.
- **Scenario 4:** Retrofitting existing platforms in order to minimise flaring and reduce emissions.

Scenario 1 – Constrained Offshore Renewable Resources

The most abundant offshore renewable resources are found to the north of the UK mainland. They are currently undeveloped as there are no routes to export the power due to the cost of transmitting electricity from the Northern North Sea to the high demand centres in the south of Scotland and England.

Offshore wind currently supplies 8% [11] of the UK's total electricity generation. Work undertaken previously by Aquatera suggests that there is an installed capacity of approximately 300 GW of offshore wind in the seas to the north of Scotland, which could generate 1,576 TWh of electricity per year. This work also indicated that, in terms of wave energy, an installed capacity of approximately 167 GW in the seas around the north of Scotland could generate 438 TWh of electricity per year.

This gives a total of around 2,000 TWh of electricity / year, whilst the total UK electricity generation for 2018 was 333.9 TWh [11], unlocking these potential wind and wave resources represents a significant opportunity for helping to totally decarbonise the UK's energy generation and secure the UK's future energy supply.

The main focus of this project is the repurposing of offshore assets. As a result, scenario 1 will not be subject to the same degree of analysis as scenarios 2, 3 and 4.

Nonetheless, floating offshore wind represents a substantial opportunity to make use of the best of UK wind and wave resources to generate hydrogen at scale.

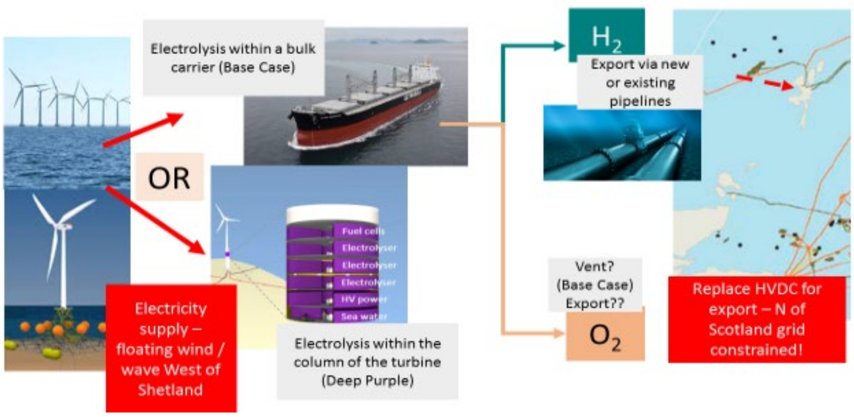

Figure 10 – Scenario 1 Depiction (Electrolysis)

This scenario assumes that the PEM electrolysis infrastructure is housed in a converted bulk carrier (estimated cost £13 million [12]) with the electrical supply from the individual wind turbines gathered through a single point mooring (SPM) at an estimated cost of £17 million. This option is considerably cheaper than using a Floating Production Storage and Offloading vessel (FPSO) which was estimated to cost c£300 million [13].

It is envisaged that the high purity green hydrogen (99.999%) would be transported to Shetland for storage and export via a short, dedicated pipeline.

Scenario 2 – Repurposing of Large Offshore Assets

This scenario is focused on repurposing of the large offshore assets in the Northern North Sea (NNS) and the Central North Sea (CNS). These assets are typically able to carry topsides weights of 15,000-35,000 MT. The base case example that has been selected is in the Brent field where there is good access to several key resources for hydrogen production. This includes assets that produce gas (to be used for SMR and G2G), export routes for hydrogen and other products, prospects for CCS and already decommissioned assets.

Repurposing for Reforming

In order to assess this production scenario, it is assumed that natural gas, required for reforming, will be sourced via a new pipeline from a nearby asset (base case) or Brent infrastructure (assumed up to 10km distance). The hydrogen produced via this process would then be exported via far north liquids and associated gas (FLAGS) pipeline as a blended product (assumed 2km of pipeline required). The CO_2 produced would be exported to a nearby asset for subsurface storage (assumed up to 10km distance).

Figure 11 – Scenario 2 Depiction (Reforming)

Although CCS is the base case assumption, there may be opportunities for using CO_2 for Enhanced Oil Recovery (EOR), as the volumes of CO_2 that could be generated are within the feasibility envelope. Though these opportunities are very asset specific.

Pipeline configurations are also location specific, and requirements for additional pipelines will be based upon suitability of existing pipelines for hydrogen service. Guidance on suitability can be found in section 5.

Repurposing for Graphene

Repurposing for graphene assumes that natural gas will be sourced from a nearby asset (base case) or through Brent infrastructure. The hydrogen produced via this process would then be export via FLAGS as a blended product. The graphene would then be transported via ship to shore.

Repurposing for Renewables

This scenario assumes the installation of electrolysers on a decommissioned structure such as Brent Bravo or Delta. The hydrogen produced from floating wind and electrolysis on the re-purposed platform would either be exported as a blended product into the FLAGS pipeline or via a new dedicated pipeline. In the base case, any O_2 produced as part of the reaction will be vented.

Scenario 3 – Repurposing of Small Offshore Assets

The technology solutions for scenario 3 are similar to scenario 2; assets will be considered for repurposing for reforming, for graphene production and for electrolysis. Therefore, the three options will not be discussed in any further detail. However, there are some considerable differences in location and operating conditions between the Northern North Sea and the Southern North Sea. This results in different inputs for this scenario which may have an impact on overall economics and warrant this area of the sea being considered as a separate scenario.

The main differences between scenarios 2 and 3 are as follows:

- The location of this scenario is focused on SNS assets
- Assets within the SNS are in shallower water and closer to shore
- The footprint and weight associated with SNS assets are lower
- HVDC costs are likely to be much lower but there is also less wind resources in an electrolysis scenario

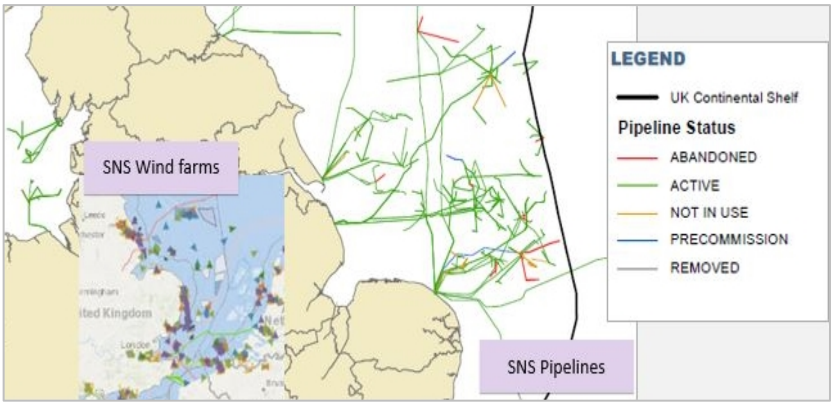

Figure 12 – Scenario 3 SNS Wind Farms and Pipeline Infrastructure

- There is more potential for gas storage in disused pipelines and / or reservoirs for CCS

These small SNS assets may also provide an opportunity for testing of offshore hydrogen generation and applications on a small scale.

Scenario 4 – Retrofitting an Existing Asset

This scenario is specifically focused on assets that currently flare gas and are not planned to be decommissioned in the near future. Flaring typically occurs because the asset in question is stranded, has limited gas processing capability and / or limited access to a gas export route and as a result cannot dispose of the gas accordingly. As a result, the asset has no means of utilising or disposing the produced gas and it has to be flared.

If that gas is used to produce hydrogen instead, this may introduce a new business stream for the asset operator, as well as having an effect on carbon reductions.

Carbon reductions in this case are twofold; firstly, as a result of decrease in flaring of hydrocarbons and secondly through the production of low carbon energy for use elsewhere.

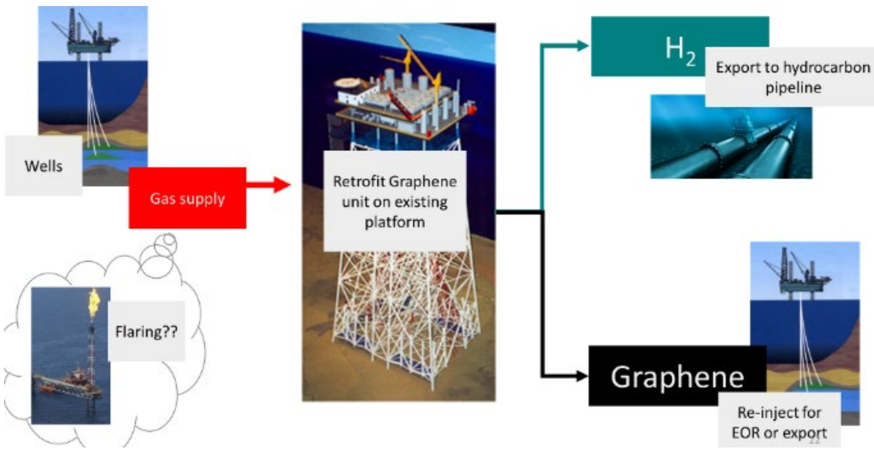

Figure 13 – Scenario 4 Depiction (Gas to Graphene)

Additionally, if hydrogen is produced via gas to graphene technology then this will create a potentially lucrative product whilst decarbonising flaring and reducing costs associated with CO_2 emissions and flaring consents.

For the purposes of this scenario, the technology to be retrofitted will be housed in a 40’ container, the available footprint will be 67m^3 and a maximum available weight of 26.7 MT.

Each scenario described within this section provides a base case plus sensitivity analysis for the financial analysis in section 7 of this report.

7. Financial Analysis for Hydrogen Offshore

In Phase 1, a detailed financial analysis was completed to better understand the lifecycle costs for offshore hydrogen production. The financial analysis was based upon the technology selection and scenarios scopes discussed in this document.

7.1 Financial Analysis for Offshore Hydrogen

A levelised cost of hydrogen model (LCOH) model was provided by BEIS. However, this project includes a number of additional parameters that are not captured in the counterfactual model.

The HOP financial model calculates the LCOH based upon a set project discount rate and various other inputs that are specific to each scenario and technology. The model then allows a sensitivity analysis to be performed to determine the impact on the LCOH of varying key parameters.

The model developed can produce as outputs:

- The Internal Rate of Return (IRR) for a project based upon a set price for hydrogen;
- The Net Present Value (NPV) of a project based upon a set price for hydrogen and a given discount rate
- The LCOH based upon a set project discount rate and a Net Present Value of zero

Sensitivities within Scenarios

The model also includes sensitivity analysis of other key input parameters (up to 13 in total including discount rate) for each of the modelled scenarios identifying a Low, Medium and High case for each. The parameters Low to High range is considered reasonable for each of the input parameters and provide a means to determine "best case" and "worst case" costs of hydrogen produced offshore. For each scenario, the four most impactful input parameters were identified and varied across a matrix.

These parameters are shown below:

Scenario	4 Key Sensitivity Parameters
1 – Wind & Electrolysis	Cost per PEM unit, Discount Rate, Unit Cost of Electricity & Price of Oxygen
2a – Large Asset with Electrolysis	Cost per PEM unit, Export Pipeline Length, Unit Cost of Electricity & Price of Oxygen
2b – Large Asset with SMR	Cost per SMR unit, Discount Rate, Unit Cost of Natural Gas & Carbon Dioxide Transport Costs
2c – Large Asset with G2G	Graphene Unit Operating Costs, Unit Cost of Electricity, Unit Cost of Natural Gas & Price of Graphene
3a – Small Asset with Electrolysis	Cost per PEM unit, Export Pipeline Length, Unit Cost of Electricity & Price of Oxygen
3b – Small Asset with SMR	Cost per SMR unit, Number of SMR Units, CCS Unit Cost & Unit Cost of Natural Gas
3c – Small Asset with G2G	Graphene Unit Operating Costs, Unit Cost of Electricity, Unit Cost of Natural Gas & Price of Graphene
4b – Retrofit SMR	Cost per SMR unit, Number of SMR units, Discount Rate & Decommissioning Deferment Benefit
4c – Retrofit G2G	Graphene Unit Operating Costs, Unit Cost of Electricity, Unit Cost of Natural Gas & Price of Graphene

7.2 Financial Analysis Results

Using the model to calculate the LCOH for all the scenarios identified above yields the following results:

Description	£/MWh	£/kNm^3	£/kg
Scenario 1 – Wind & Electrolysis	£141	£423	£4.70
Scenario 2a – Large Asset with Electrolysis	£137	£410	£4.55
Scenario 2b – Large Asset with SMR	£99	£296	£3.29
Scenario 2c – Large Asset with G2G	£0	£1	£0.01
Scenario 3a – Small Asset with Electrolysis	£140	£419	£4.66
Scenario 3b – Small Asset with SMR	£104	£311	£3.45
Scenario 3c – Small Asset with G2G	£0	£1	£0.02
Scenario 4b – Retrofit SMR	£64	£192	£2.14
Scenario 4c – Retrofit G2G	£0	£0	£0.00
Counterfactual on equivalent basis	£70	£211	£2.35

The results above show that hydrogen production using the G2G process produces the lowest LCOH for offshore application across all scenarios. Across all scenarios, the decommissioning deferment cost has a significant impact on the overall LCOH. Note, the lower heating value of hydrogen has been used throughout. A discussion of the results is presented below.

7.3 Financial Analysis Results Discussion

Hydrogen by G2G

The financial case for the G2G system is very compelling as a result of the high market value of graphene. The current market price is very high as much as £50 - £180/kg [14] but the market size is still relatively small. If, as predicted, graphene finds mass use cases, the cost can be expected to fall with volume. For the purposes of modeling the graphene sales for this project, a highly conservative price of £3/kg was used for the Medium cases.

The high market value of graphene provides a zero or negative LCOH, meaning that effectively the hydrogen could be sold at zero cost or a very low market price and the overall production scheme would still be economical.

This is still an emerging technology (and market) but could benefit from the modular unit approach being envisaged for testing and refining containerised units for SMR and electrolysis units offshore.

Hydrogen by SMR

Despite the relative high costs of the modular SMR units, the hydrogen produced by SMR has a median LCOH. The HOP financial model also includes costs associated with CCS, however it is unclear if this is also the case for the BEIS counterfactual. In a number of the scenarios the SMR example, however, can improve upon the counterfactual costs. This is helped by including the decommissioning benefit in reusing existing jackets. In addition, the learning by doing analysis, described below in 7.4, shows these costs could fall substantially as modules are mass produced for use in the North Sea market and elsewhere.

Hydrogen by Electrolysis

The case for electrolysis also looks attractive as, although it is more costly than SMR produced hydrogen, there is a higher market price for high purity hydrogen to be used in fuel cells for transport (vehicles, ships etc.). Even when a dedicated pipeline to shore is feasible. It can also be expected that costs will fall dramatically with mass production and learning by doing effects. Additionally, if oxygen can be sold at the industrial price it currently attracts this could benefit the project economics. This sensitivity is not currently included in the project economics.

7.4 Learning by Doing

All of the offshore hydrogen production scenarios identified through the HOP project envisage the production of modular units to produce hydrogen. Whilst initial capital costs are relatively high in a modular approach, an advantage of the process of producing multiple units is the potential for cost reduction from 'learning by doing'.

Learning by doing cost reduction and performance enhancement effects are seen in many products and processes deployed at volume into the market. Learning by doing is seen in virtually all industries, ranging electricity generation, to shipbuilding, to computers and mobile phones, to the cost of oil well development and to aeroplanes and the cost per passenger air mile flown.

Analysis was undertaken to understand the potential impact of learning by doing through replication across assets but also through learning via a test facility. A conservative learning rate of 10% was applied (wind industry learning rate is circa 12 – 15%).

The learning rate is based on a current estimated market deployment of 48 SMR module units. To meet the BEIS counterfactual scale, 396 units would be required and a cost reduction of >27% could be expected from the series production, based on a 10% learning rate. The potential impact of learning by doing for offshore SMR is shown in Figure 14 below:

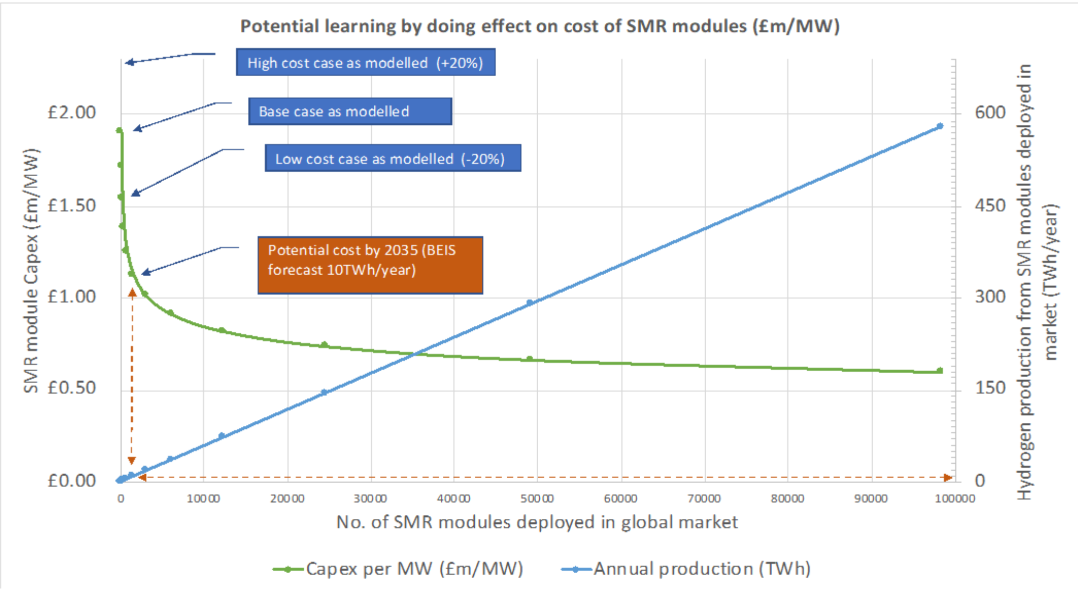

Figure 14 – SMR Offshore Learning by Doing Curve

7.5 Improving Certainty in Financial Analysis

Scenarios that require CCS are highly sensitive to location as CO_2 transport and storage costs are high. A Phase 2 scope for HOP has been developed which will look to build a business case for offshore operators and look more closely at the CCS challenges, including providing guidance on the commercial frameworks required.

Uncertainty currently exists around the refurbishment and inspection costs in order to re-purpose pipelines for hydrogen service, which will also be addressed in Phase 2. Further refinement is also needed in understanding the potential costs of modifying the technology for offshore deployment. This will be addressed with vendors in Phase 2 and confirmed through testing at the H^2O.

Additionally, the commercial feasibility of a number of scenarios are impacted by the market for the additional products, graphene for G2G and oxygen in the electrolysis scenarios. The market for these will be further quantified in Phase 2 of the HOP project.

8. Industrial Hydrogen Hub at Flotta

A number of the technologies identified in this project are commercially available in a containerised form. However, common to all is the immaturity of hydrogen systems and associated infrastructure to merge with the generic offshore scenario. A test facility operated by personnel with offshore integration knowledge is needed to accelerate these technologies from their current commercial state to ready for deployment offshore.

The Hydrogen Hub Orkney (H^2O) proposed in this project would provide a facility which can receive the production equipment in a controlled environment, progress the necessary modifications and optimisation and interrogate HSE/control and environmental robustness.

8.1 H^2O Objective Statement

The objective of the H^2O is to provide potential Technology Users with qualitive sets of data for informed technology selection. To support this, the H^2O will offer services which will enable the following:

- Product testing technology readiness level (TRL) progression and associated life cycle data
- Immature technologies performance data: H_2 / Capex, H_2 / Footprint, H_2 / weight, H_2 / CO_2
- Mature technology testing life cycle data: control and operational assessments including unmanned operation performance and intervention frequency, CAPEX/OPEX, weather and corrosion performance
- Transport and Storage performance data: long term materials exposure monitoring along with production storage offloading options

Test Facility Location – Flotta

It is proposed that the H^2O will be constructed on the isle of Flotta in Orkney. Key strengths for this location are:

- There is an advanced renewable energy infrastructure within Orkney that has extensive public support for hydrogen schemes with several in operation
- Flotta Oil Terminal has brownfield sites for potential development
- Ship to ship transfer system established in Scapa Flow for potential transport options for hydrogen
- Proximity to North Sea oil & gas industry with physical pipeline connection
- An established technology test site already exists at the Flotta Oil Terminal, operated by NOV
- Coastal / exposed site to capture stepping stone towards offshore environment.

NOV currently operate the Orkney Water Test Centre which is situated on the Flotta Oil Terminal. This business stream of NOV specialises in technology testing and development.

This expertise can be transferred to hydrogen technology development, given the skill base and experience, providing an accelerated creation of a national test facility for hydrogen. A map of the proposed site for the H^2O is shown in Figure 15.

Figure 15 – Scenario 4 Depiction (Gas to Graphene)

8.2 Hydrogen Hub Orkney

The Hydrogen Hub Orkney is to be comprised of a Steel Portal Frame Building to house lab space, offices, welfare facilities and a plant room. The exterior will have segregated test bays sized to accommodate the short-listed technologies and a hazardous materials storage area. Site layout diagrams, process flow diagrams and utility requirements are included in Appendix C.

High Level Operating Philosophy

Initial engagement of technology vendors has already happened as part of Phase 1. Within Phase 2, a key activity will be agreeing testing requirements with the selected technology providers. When the H^2O is constructed, equipment would be received on Flotta by way of trailer mounted containers. The equipment will be lifted and placed in position by use of NOV lifting capability and/or sub-contracted crane hire.

A visual assessment of the equipment, review of Risk Assessment and Method Statement (or equivalent) will be carried out and a pre-agreed installation and commissioning plan will be reviewed for sign off. With acceptance that the equipment is in the correct condition and procedures have been approved by competent authorities, hook-up to feed utilities will commence followed by leak testing or equivalent. Production connections will commence with similar checks.

A thorough safety procedure will be carried out before any energising and/or operation of equipment both within the vendors supply and within the test facility supply. A commissioning and/or operation procedure will then be put into action which will be respective of the vendor's development requirements.

The test will begin, and data will be recorded by the test facility where required for post testing interrogation. Dependent on vendor requirements, development activities may take place on site for secondary testing.

Outline Cost Breakdown

Budgetary quotes have been obtained from local vendors based on the layout diagrams shown in Appendix C. The total cost estimated for the H^2O is £6.3M. A breakdown of these costs is given in the table below:

Item	Total Cost (inc 17.5% Contingency)
Civil & Building Works	£1,400,000
Utilities	£1,670,276
Plant & Equipment	£3,217,363
TOTAL	**£6,287,639**

8.3 Technology Test Plan

As part of the process towards signing up vendors and development of technology there needs to be a predetermined Test Plan agreed with the developers that sets out the main aims of testing. Given the range of hydrogen production technologies that might be tested at the H^2O, there will be equipment which will have areas in common, albeit with differing development challenges towards offshore deployment.

To this end, there will be a technology specific test plan tailored for each system but generated from a base case template. The information required to detail the Test Plan will be a 2-way process between the test facility operators and the technology developers where a final plan will be signed off by both parties.

However due to inherent nature of technology research and development testing, any plan or procedure will have to be treated as a 'live' document and will be subject to modification/revision as the products and processes provide data under test. The base case template will consist of the following key areas: Introduction, Technology, Offshore Deployment, Test Site Overview, External Constraints, Testing Parameters, Analytical Methods, Schedule, Method Statement and Reporting.

Testing Parameters

This will largely take the form of a testing matrix in spreadsheet form and will confirm all parameters that are required to be measured during operation. This will be limited by the facility metering and analysis instrumentation and techniques and will include some of the following:

Flowrate, Pressure, Temperature	Gases and Water Quality / Purity	Power	Other
• Inlet water and / or gas • Outlet water and / or gas • Efficiencies	• Inlet specifications • Outlet specifications	• Voltage, current, harmonics etc. • Consumption /efficiency	• Graphene weight and quality • Operational interface and control regime • Suitability for unmanned operations • Start-up procedures • Noise • Weathering • Maintenance and intervention requirements • HSE and waste stream impacts • Communication systems

8.4 H^2O Business Case

The Hydrogen Hub Orkney will allow Hydrogen production equipment to be installed, tested and then redeployed offshore on demonstrator projects in the shortest possible time frame. The test facility allows developers to prove their technology in a controlled onshore environment, facilitating their development offshore and providing a route for accelerated commercial deployment. This allows us to produce hydrogen at scale by virtue of re-use of offshore infrastructure.

The business plan looks at the running costs of such a facility whilst focusing on primary revenue generated from test ‘bay’ rental, secondary revenue being generated by testing of associated hydrogen infrastructure and auxiliary equipment (metering, monitoring, storage, HSE systems etc.) and tertiary revenue from production sales (hydrogen, bi-product gases and graphene). Sales of the latter will be dependent on production rates and frequency to allow them to become economically viable.

The range of hydrogen production technologies are at varying TRLs, some are commercially available, and others require more development. This is assessed when considering an onshore application and it is therefore widely accepted that there is a need for this type of test facility to allow the optimisation and adaptation for offshore deployment.

The advancement with this type of technology will ensure the UK, as with renewable energy, is at the forefront of developing technology and investment. As hydrogen is seen as a ‘clean’ source of energy its environmental credentials are also in demand as countries, operators and developers seek to decarbonise and reduce their reliance on hydrocarbons.

In order to assess the initial ‘base case’ business plan, the secondary and tertiary revenue streams mentioned above have been omitted; only revenue from the test bays has been considered. The limiting factors for the base case business plan, as it stands, is the number of bays. The plan conservatively estimates occupancy levels at between 25% and 35% of capacity.

Costs associated with the operation of a test facility, management, sales & marketing and finance & legal make up the day to day running costs and have been included in the base case assessment. On this basis, and with the occupancy levels outlined above, a forecast profit as early as Q4 year one is achievable; cash flow would only become positive in Q1 year 5. Given the conservative occupancy assumptions, it is also feasible the profit and cash flow dates could be earlier.

9. Conclusions & Next Steps

9.1 Project Conclusions

Phase 1 of the HOP project considered the market for offshore hydrogen production, hydrogen production technologies suitable for the offshore environment and built feasible scenarios for offshore hydrogen schemes. The project also addressed the ability to re-use the existing pipelines infrastructure for hydrogen service, completed financial analysis and proposed initial design for the Hydrogen Hub Orkney on Flotta.

The project yielded the following key conclusions:

- **Market for Offshore Hydrogen:** Addressing future energy requirements will be challenging and the UK should make the most of all available infrastructure. Considerable opportunity exists to re-purpose offshore assets for hydrogen service upon cessation of production of oil and / or gas.
- **Hydrogen Production Technologies:** Four technologies have been identified as suitable for hydrogen production offshore. Those are Steam Methane Reforming with Carbon Capture and Storage, Gas to Graphene technology, PEM electrolysis and Alkaline Electrolysis. Common to all is the need for further containerisation and certification for unmanned offshore deployment.
- **Scenarios for Offshore Hydrogen:** Utilisation of offshore assets has resulted in four scenarios being identified for hydrogen production. These include full re-purposing of asset topsides (large and small), retrofitting to operational assets and harnessing wind and wave resources for electrolysis. A large offshore asset completely re-purposed for hydrogen could produce circa 20,000kg per day of hydrogen.
- **Pipeline Re-Use for Hydrogen Service:** The Phase 1 project suggests that approximately 30% of the existing pipelines could be repurposed for the transportation of hydrogen. The initial study also found that a small subset of the pipelines could be used to transport CO_2. Both of these findings require further work.
- **Financial Analysis for HOP:** Deferment in decommissioning cost provides an attractive mechanism to support the financial case for offshore hydrogen production. Hydrogen production using the G2G process produces the lowest LCOH for offshore application. There is additional opportunity to reduce the LCOH for offshore by circa 25% through learning by doing.
- **Hydrogen Hub Orkney:** The cost for construction of the H^2O will be circa £6.3m. The H^2O is expected to be operational in 2021 and could be profitable within one year of operation. It will support the development of all hydrogen technologies, in addition to those specifically identified in this project.

Re-use of offshore infrastructure generates several commercial opportunities to both produce hydrogen at scale and potentially at lower cost. Part of the cost saving includes extension of asset life, deferment of decommissioning costs and the provision a low cost, medium volume hydrogen storage mechanism.

The activity completed in Phase 1 of the project did not identify any technical or regulatory barriers for the progression of hydrogen production offshore; although it is acknowledged that further development in both areas is required. Additionally, development of a commercial framework is required to present hydrogen as a credible business alternative.

9.2 Next Steps

Phase 1 of the HOP project has made considerable progress in developing a solution for the production of hydrogen offshore utilising existing oil & gas infrastructure. The Phase 2 scope has two primary elements:

- The establishment of the Hydrogen Hub Orkney (H^2O) to facilitate testing and onwards deployment of the technologies for offshore use
- The front end engineering design work will be completed to allow the installation of hydrogen technology to an offshore asset.

These two scopes are required to happen in parallel in order for us to achieve the scale of hydrogen production required by the UK.

10. References

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[4] – Chris Stark, Scottish Government Presentation at Scottish Renewable Annual Conference (https://www.gov.scot/binaries/content/documents/govscot/publications/speech-statement/2015/06/heat-policy-statement-towards-decarbonising-heat-maximising-opportunities-scotland/documents/00478997-pdf/00478997-pdf/govscot%3Adocument/00478997.pdf)

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[6] – RR1047 Injecting hydrogen into the gas network – HSE

[7] – https://www.iea.org/publications/freepublications/publication/TechnologyRoadmapHydrogenandFuelCells.pdf

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[9] – Marginal Developments Solution Centre, Integrated Energy Strategy, May 2019, Highland Potential

[10] – Hydrogen as an Energy Carrier, DNV GL, 2018

[11] – BEIS 2019 UK Energy Statistics, 2018 & Q4 2018

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[13] – Offshore Technology, https://www.offshore-technology.com/projects/vargfieldnorway/

[14] – www.graphene-info.com

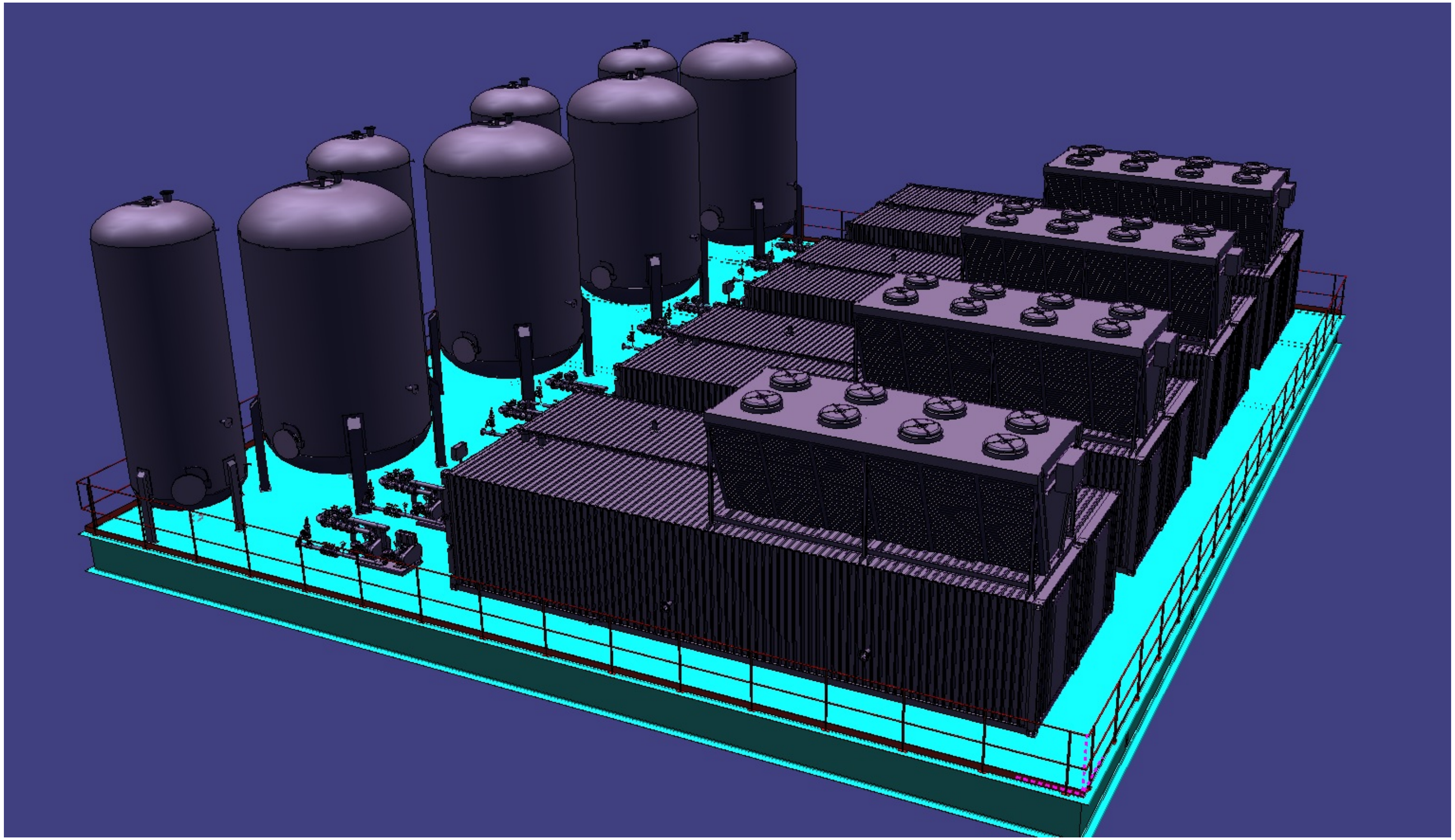
11. Appendices

Appendix A – Offshore Platform Plans

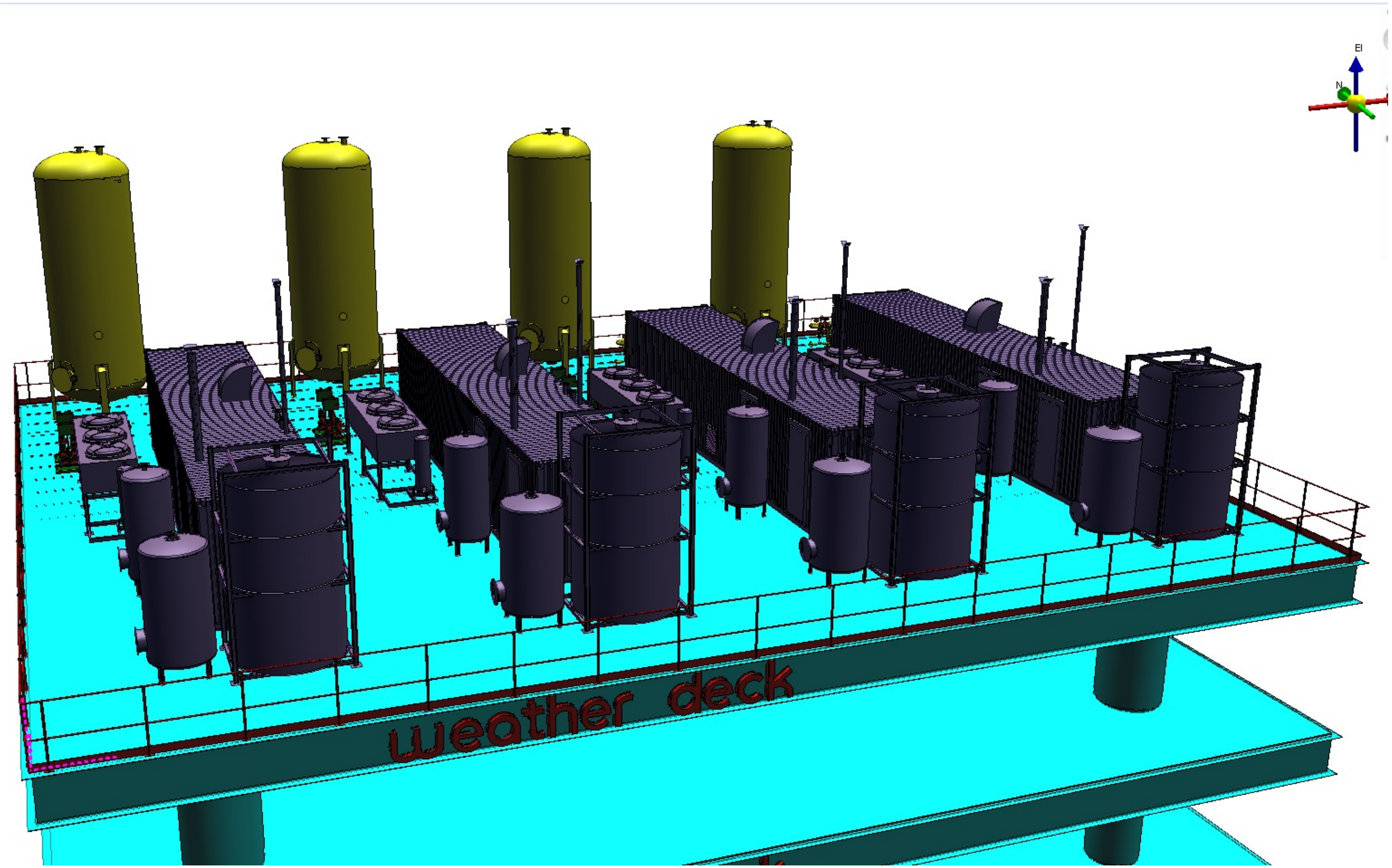
Appendix B – UK Pipelines Map for Hydrogen Service

Appendix C – Hydrogen Hub Orkney Facility Diagrams

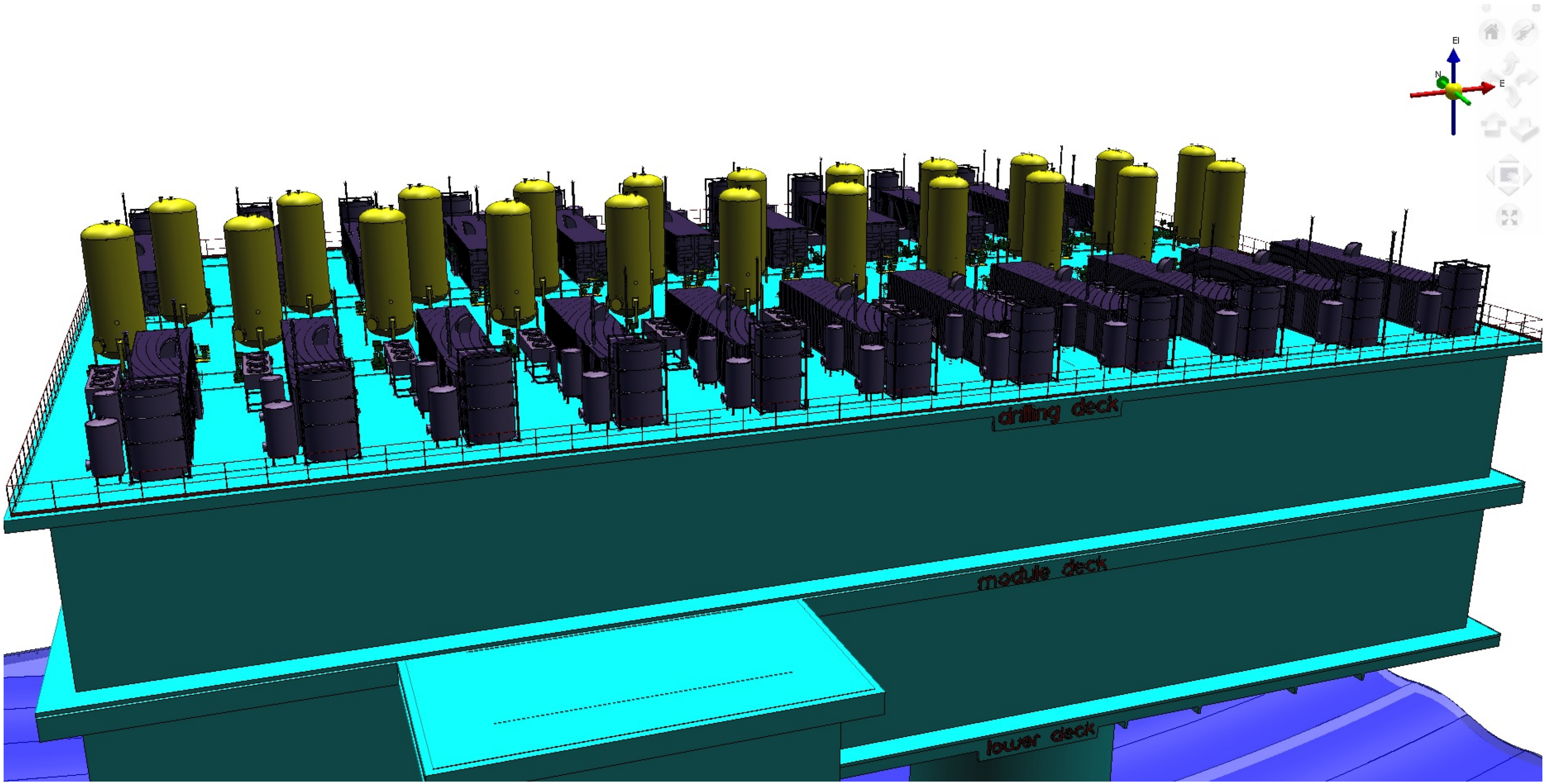
Appendix A – Offshore Platform Plans



Markham Layout with PEM

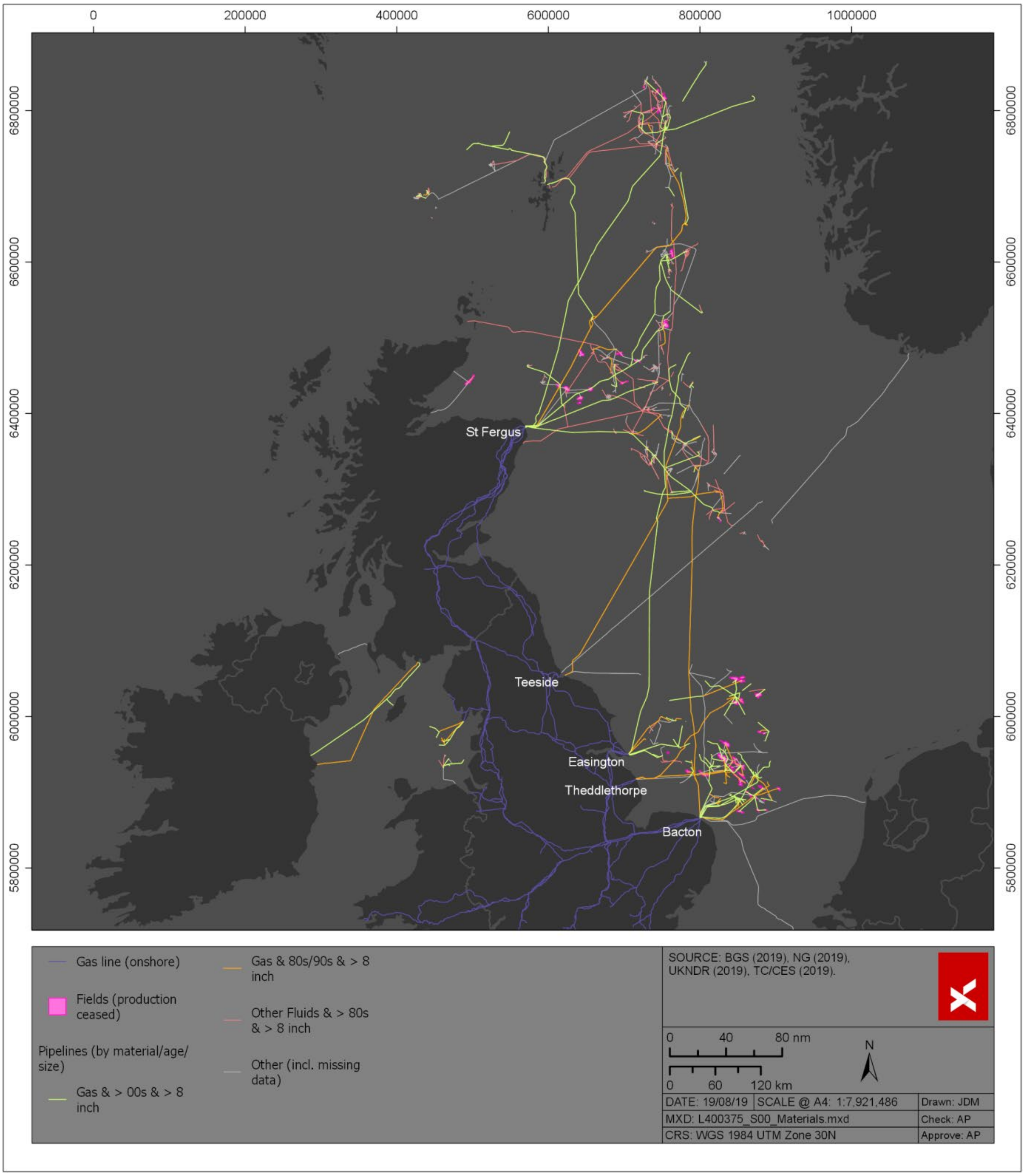


Markham Layout with SMR

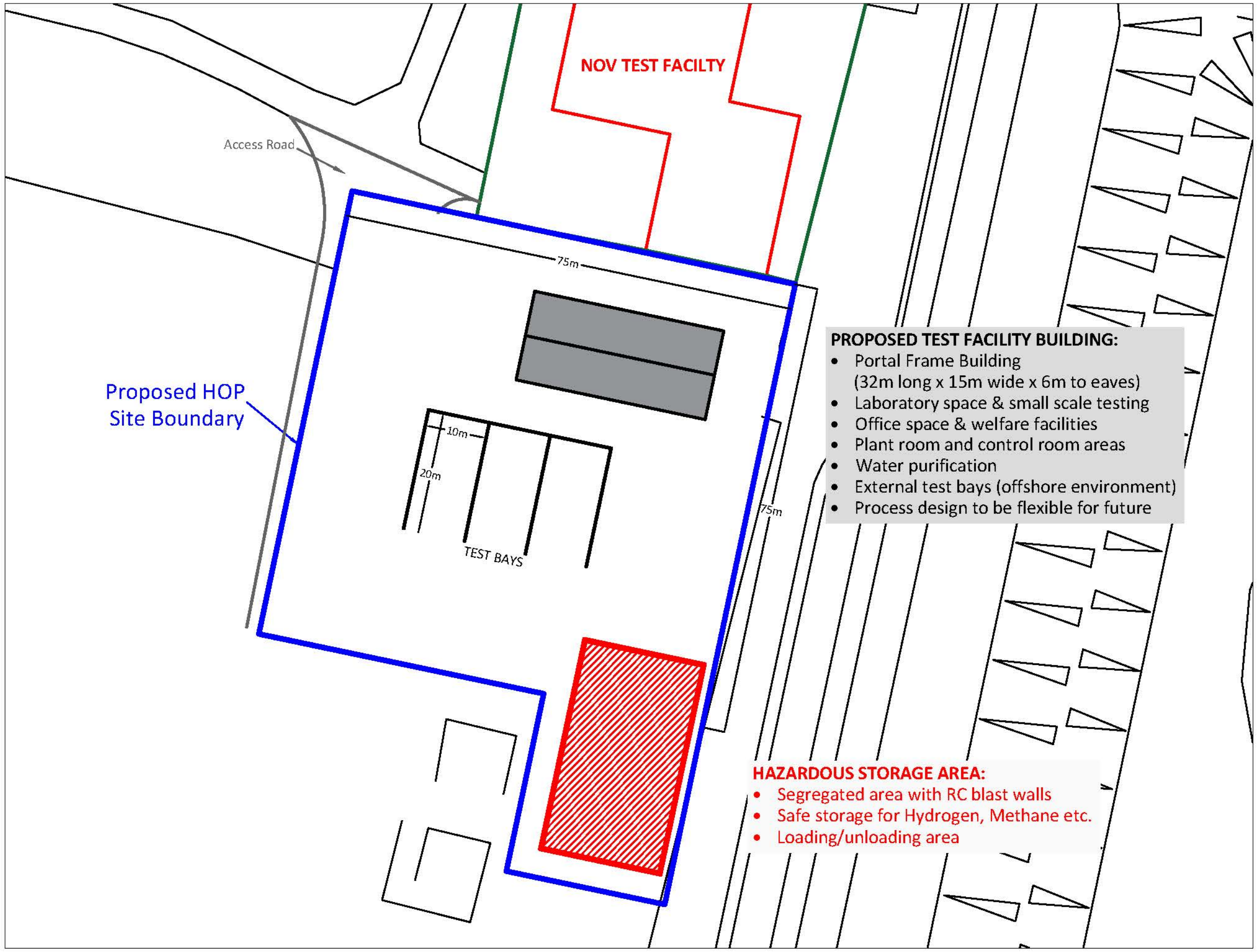


Brent Delta Layout with SMR

Appendix B – UK Pipelines Map for Hydrogen Service

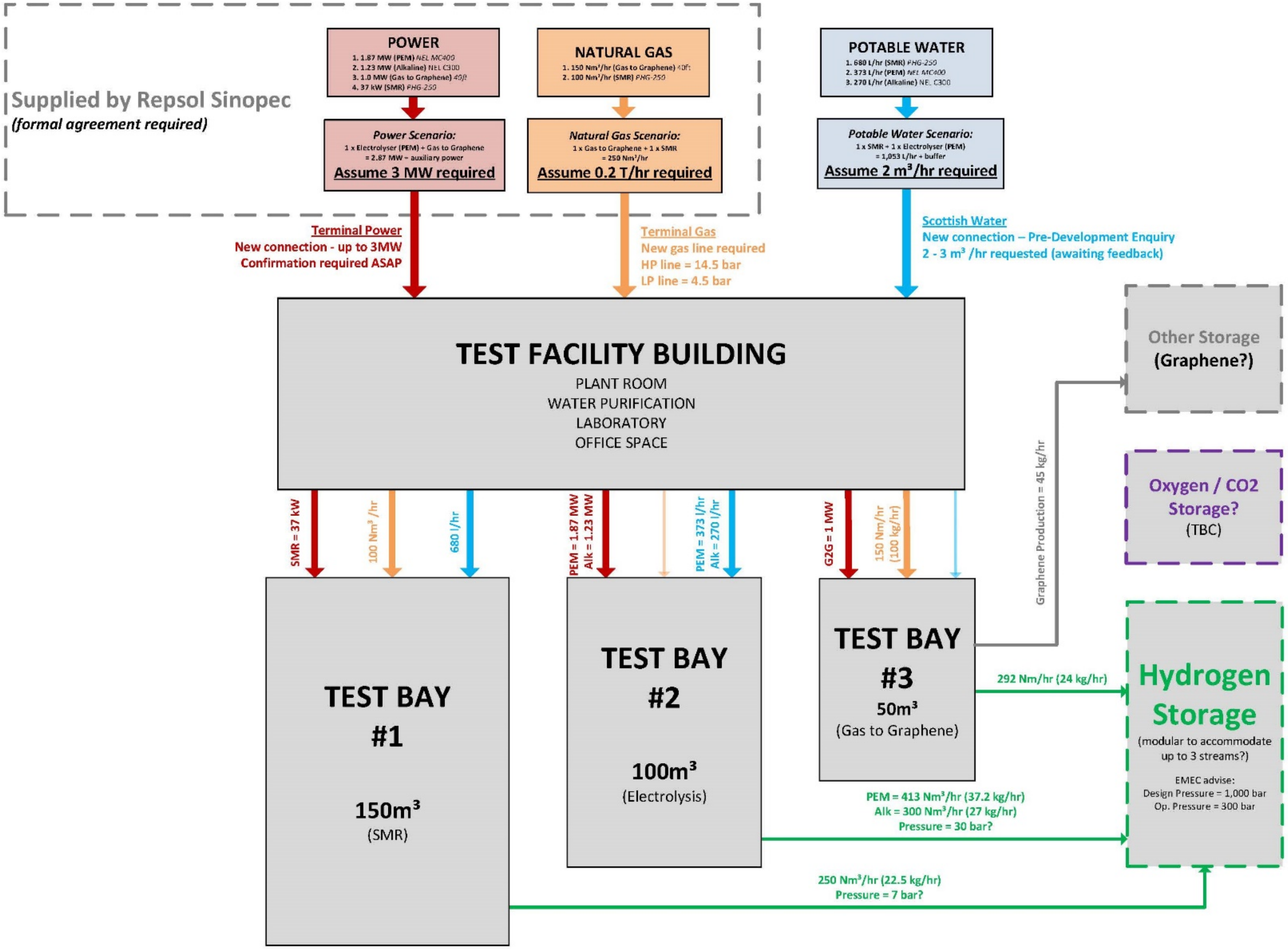


Appendix C – Hydrogen Hub Orkney Facility Diagrams

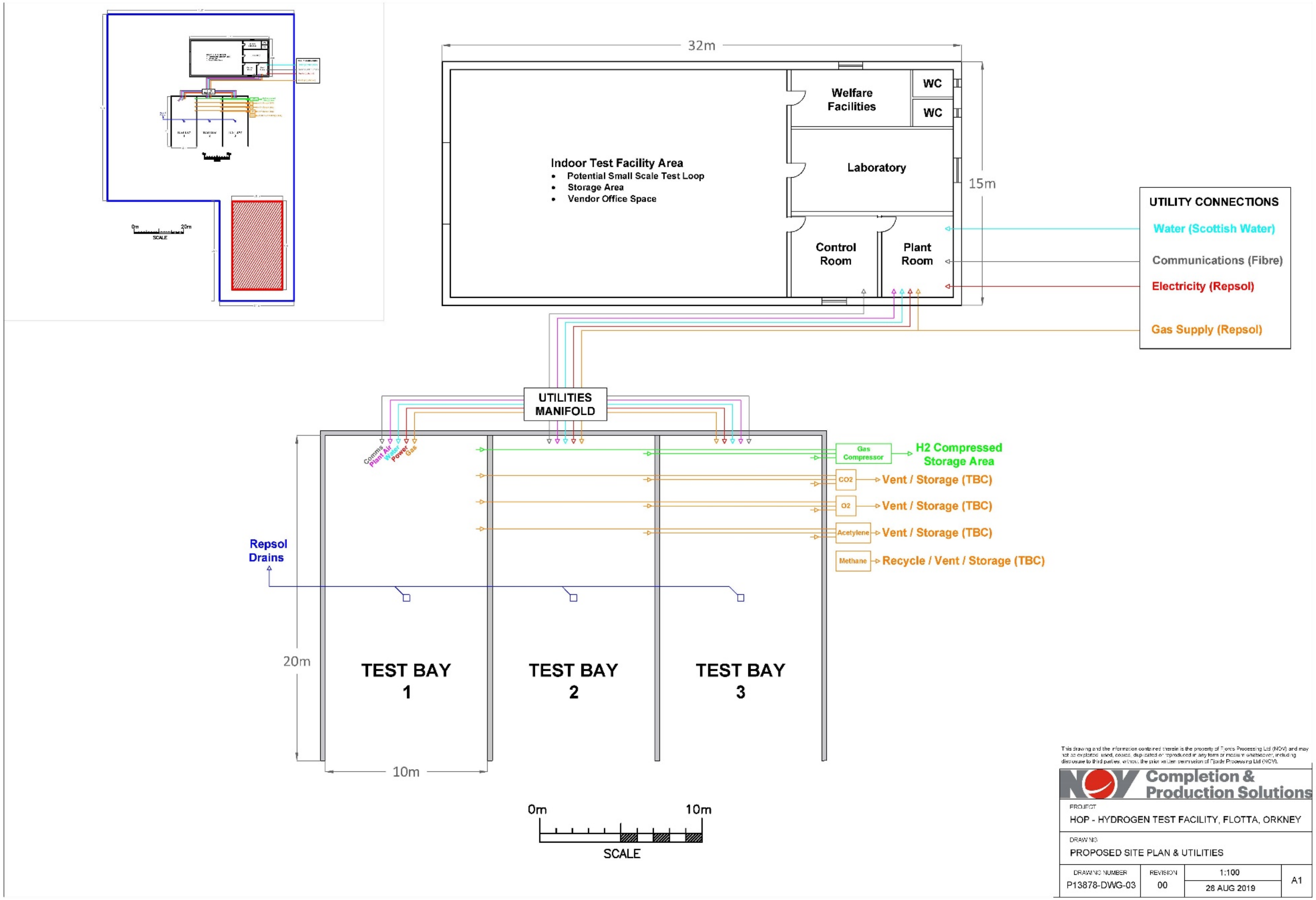


Facility Layout

Proposed Hydrogen Test Facility – High Level PFD



Facility PFD



Facility Utilities