Department for
Business, Energy
& Industrial Strategy

Net Zero Teesside & Northern Endurance Partnership Technology Plan

Key Knowledge Document

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Acknowledgements

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1.0 Foreword

The Net Zero Teesside (NZT) project in association with the Northern Endurance Partnership project (NEP) intend to facilitate decarbonisation of the Humber and Teesside industrial clusters during the mid-2020s. Both projects will look to take a Final Investment Decision (FID) in early 2023, with first CO2 capture and injection anticipated in 2026.

The projects address widely accepted strategic national priorities – most notably to secure green recovery and drive new jobs and economic growth. The Committee on Climate Change (CCC) identified both gas power with Carbon Capture, Utilisation and Storage (CCUS) and hydrogen production using natural gas with CCUS as critical to the UK's decarbonisation strategy. Gas power with CCUS has been independently estimated to reduce the overall UK power system cost to consumers by £19bn by 2050 (compared to alternative options such as energy storage).

1.1 Net Zero Teesside Onshore Generation & Capture

NZT Onshore Generation & Capture (G&C) is led by bp and leverages world class expertise from ENI, Equinor, and TotalEnergies. The project is anchored by a world first flexible gas power plant with CCUS which will compliment rather than compete with renewables. It aims to capture ~2 million tonnes of CO2 annually from 2026, decarbonising 750MW of flexible power and delivering on the Chancellor's pledge in the 2020 Budget to "support the construction of the UK's first CCUS power plant." The project consists of a newbuild Combined Cycle Gas Turbine (CCGT) and Capture Plant, with associated dehydration and compression for entry to the Transportation & Storage (T&S) system.

1.2 Northern Endurance Partnership Onshore/Offshore Transportation & Storage

The NEP brings together world-class organisations with the shared goal of decarbonising two of the UK's largest industrial clusters: the Humber (through the Zero Carbon Humber (ZCH) project), and Teesside (through the NZT project). NEP T&S includes the G&C partners plus Shell, along with National Grid, who provide valuable expertise on the gathering network as the current UK onshore pipeline transmission system operator.

The Onshore element of NEP will enable a reduction of Teesside's emissions by one third through partnership with industrial stakeholders, showcasing a broad range of decarbonisation technologies which underpin the UK's Clean Growth strategy and kickstarting a new market for CCUS. This includes a new gathering pipeline network across Teesside to collect CO2 from industrial stakeholders towards an industrial Booster Compression system, to condition and compress the CO2 to Offshore pipeline entry specification.

Offshore, the NEP project objective is to deliver technical and commercial solutions required to implement innovative First-of-a-Kind (FOAK) offshore low-carbon CCUS infrastructure in the UK, connecting the Humber and Teesside Industrial Clusters to the Endurance CO2 Store in the Southern North Sea (SNS). This includes CO2 pipelines connecting from Humber and Teesside compression/pumping systems to a common subsea manifold and well injection site at Endurance, allowing CO2 emissions from both clusters to be transported and stored. The NEP project meets the CCC's recommendation and HM Government's Ten Point Plan for at least two clusters storing up to 10 million tonnes per annum (MTPA) of CO2 by 2030.

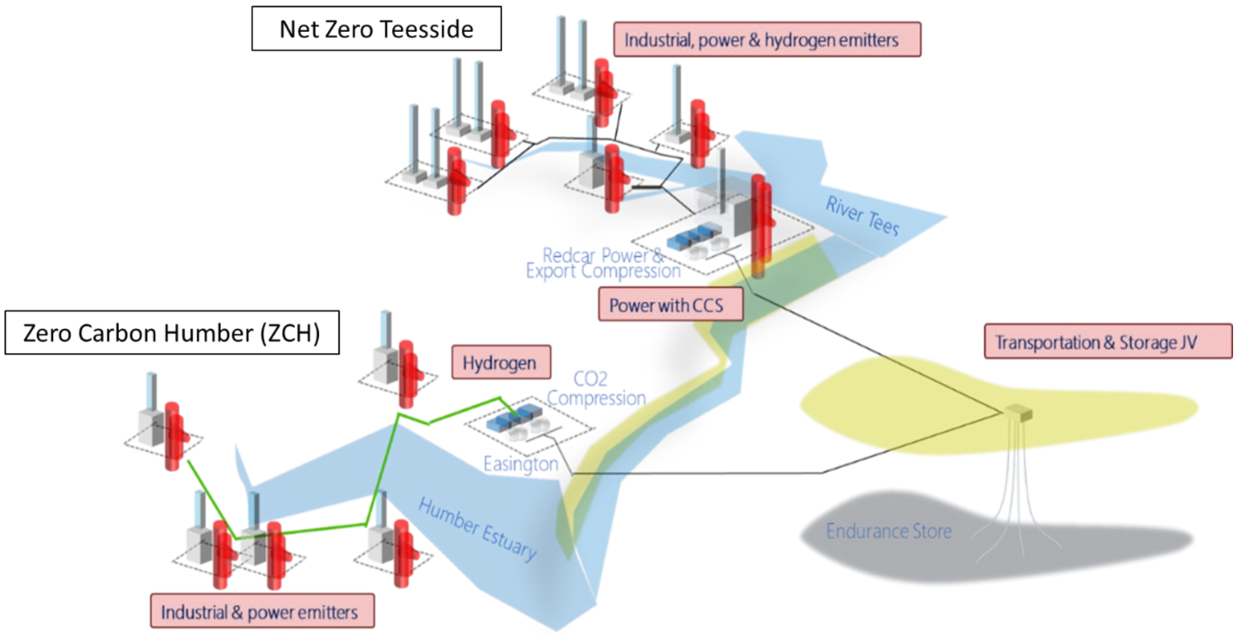


Figure 1: Overview of Net Zero Teesside and Zero Carbon Humber projects.

The project initially evaluated two offshore CO2 stores in the SNS: 'Endurance', a saline aquifer formation structural trap, and 'Hewett', a depleted gas field. The storage capacity requirement was for either store to accept 6+ MTPA CO2 continuously for 25 years. The result of this assessment after maturation of both options, led to Endurance being selected as the primary store for the project. This recommendation is based on the following key conclusions:

The storage capacity of Endurance is 3 to 4 times greater than that of Hewett
The development base cost for Endurance is estimated to be 30 to 50% less than Hewett
CO2 injection into a saline aquifer is a worldwide proven concept, whilst no benchmarking is currently available for injection in a depleted gas field in which Joule-Thompson cooling effect has to be managed via an expensive surface CO2 heating solution.

Following selection of Endurance as the primary store, screening of additional stores has been initiated to replace Hewett by other candidates. Development scenarios incorporating these additional stores will be assessed as an alternative to the sole Endurance development.

2.0 Introduction

2.1 Objective

This document drives risk reduction by systematically identifying and managing all unproven technologies on the Net Zero Teesside Project. It achieves this by:

- Recording all Serial #001s (technology that has not yet reached TRL 6) utilised by the project
- Document technology '2-pager' for each identified Serial #001 to track its qualification milestones, mitigations and contingencies

2.2 Project Overview

The Net Zero Teesside (NZT) project in association with the Northern Endurance Partnership project (NEP) is a CCUS project, based in the North East of England. The scope is different to a traditional oil and gas project with a technical definition aligned to the contracting strategy and a unique risk profile. It intends to facilitate decarbonisation of the Humber and Teesside industrial clusters during the mid-2020s in line with the UK Government's net zero targets with first CO2 capture and injection anticipated in 2026.

The overall decarbonisation of the Teesside and Humberside regions are expected to be developed in phases. There will be some pre-investment in oversizing certain aspects to enable expandability in future phases.

Phase 1 of the NZT and NEP projects aims to develop infrastructure to sequester 4 MTPA (annual average) of CO2 consisting of Power and Capture (P&C) facilities and onshore and offshore Transportation and Storage (T&S) components. The power and capture (P&C) facilities and the booster compression facilities for the T&S are co-located on the Teessworks site (previously STDC). The Endurance field where the CO2 is injected is a saline aquifer in the Southern North Sea region approximately 144 km from Teesside and 83 km from Humberside. The Layout of NEP is shown in figure 1.

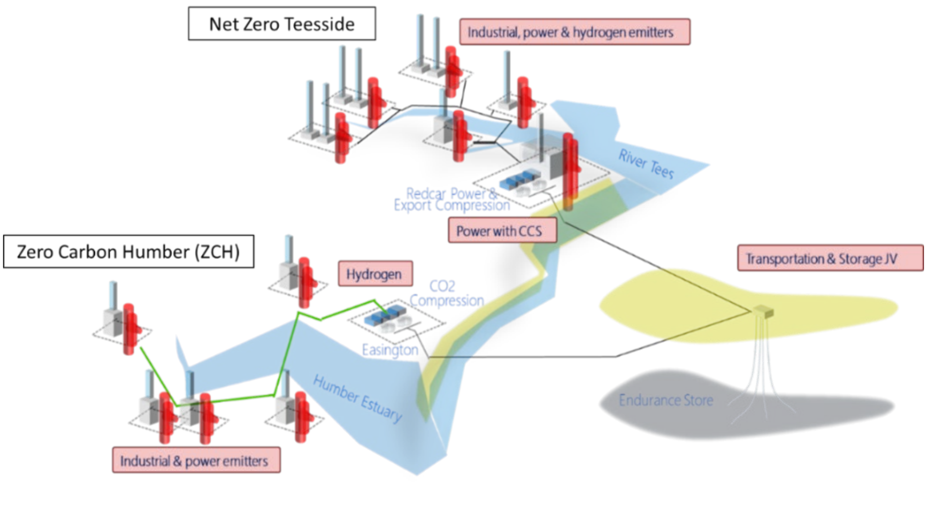


Figure 1 – NEP Overview

The P&C facilities consist of one train of a new large-scale H-class CCGT power generation (~ 850MW) operating in dispatchable mode with amine chemical absorption-based post combustion carbon capture. The capture plant is aiming to capture 95% of CO2 from the power generation, equivalent to approximately 2 million tonnes of CO2 per year. The captured CO2 will be treated and compressed to the required transport specification at the onshore gas conditioning facilities.

The onshore T&S component in Teesside will include a new medium pressure (12 – 20 barg) CO2 gathering network to collect carbon dioxide from industrial producers along with booster compression facilities to transport the collected emissions to the offshore storage site. The gathering network for Phase 1 will focus on developing infrastructure to the North of the Tees to enable decarbonisation of:industrial sources accounting for up to 1.4 M. The network will also be future proofed for additional industries on the North of the river. The phase 1 volume for Humberside will be 1.7 MTPA on an annual average basis.

The offshore T&S component consists of offshore pipelines sized for Teesside up to 10 MTPA and Humberside up to 17 MTPA to transport the collected CO2 from both clusters for injection at the Endurance storage site. It also includes subsea infrastructure developed for CO2 injection up to 4 MTPA via 6 new injection wells (5 injectors and one monitoring well) at a rate of 1 MTPA average per well.

2.3 Project Technology Philosophy

The project philosophy for developing the technology plan and managing FOAK technology risks will include:

- Early identification of technology risks through multi-functional risk workshops covering Facilities, Subsurface and Wells. Ensuring that clear TRL level and risks are assigned for each equipment type.
- Market screening & qualification of CO2 licensor and processing technologies & CO2 compressors in Optimise.
- Early market engagement to encourage suppler led innovative and integrated solutions around integration, execution methods and standards/specifications.
- Knowledge sharing and continuous engagement with industry, academia, partners, and other key stakeholders such as BEIS to incorporate latest industry developments and know-how into the project and optimise the proposed concept.
- Participation or alignment with relevant Joint Industry Projects (JIPs) on key technology risks which is common to other on-going projects.
- Developing clear qualification plans to mitigate technology risks and ensure TRL 4 is reached prior to Execute.

The project Technology plan will be reviewed by the Project team regularly throughout the project lifecycle to confirm that it has captured all relevant technology / Serial #001s as the Project evolves and that risk mitigations are progressing.

2.4 Definitions

Unproven Technology: Any practice or item that has not been successfully operating in equivalent conditions for at least three years with BP or other operators. Unproven Technologies may be enabling or enhancing.

> Enabling: A technology critical to Project success without which the Project cannot continue.
>
> Enhancing: A technology upon which the Project is not reliant, but if successfully implemented would allow more value to be realised.

Serial #001: An unproven technology that has not yet reached TRL 6 (installed and tested in similar environment).

It is important to note that an existing technology deployed in a different service, scale or environment is still considered to be a Serial #001.

Technology Readiness Level (TRL): A measure of technology maturity for a particular duty. It is quantified as per the table below. The TRL of a system is determined by the lowest sub-component TRL.

Phase	TRL	Development stage completed
Conception	0	**Unproven concept** Basic research and development or paper concept
Proof of concept	1	**Demonstrated concept** Proof of concept as paper study or research and development experimentation
	2	**Validated concept** Experimental proof of concept using physical model tests
Prototype	3	**Prototype tested** System function, performance, and reliability tested
	4	**Environment tested** Preproduction system environment tested
	5	**System tested** Production system interface tested
Field qualified	6	**System installed** Production system Installed and tested
	7	**Field proven** Production system field proven > 3 years

Figure 2 – TRL summary definitions

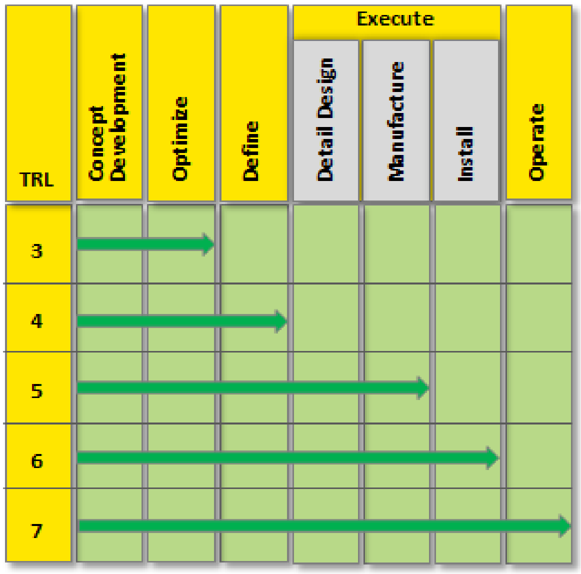


Figure 3 – TRL qualification by Project stage

2.5 Intellectual Property Strategy

This is a first of a kind project aiming to leverage market solutions as far as possible. The contracting strategy will be developed further with initial engagement with suppliers including those providing proprietary capture technologies. A detailed plan to manage any proprietary data will be developed in line with the contracting strategy – however, it is recognised transparency in information for solvents and power and capture plant design may be required to support impact assessments under the DCO consenting process. An intellectual asset management plan (IAM) will also be developed for the project.

In addition, the project operator and partners will hold the right to develop any intellectual property developed through this first of a kind project.

2.6 Key Technology Risks

The project is acknowledged as a first of a kind project incorporating a number of key new technologies to promote development of the UK's first carbon capture cluster. All the identified enabling technology risks are currently TRL 3 and above which satisfies requirements for entry to FEED. To achieve entry toFID, all enabling risks will need to reach TRL 4. The key technology risks currently at TRL 3 are:

- Full Chain Dispatchability

  The NZT power and capture plant will turn on/off to support intermittent renewables such as solar and wind, enabling decarbonization of the UK power sector. There are currently no analogous plants that demonstrate a dispatchable combined power and capture plant as far as the project is aware. Two key technology areas that need to be addressed are:

    1. Running in dispatchable mode increases risk of thermal fatigue due to more frequent start-ups within the system and may also require more advanced emissions control systems (i.e. systems to control solvent and by-product emissions in the capture plant).
    2. New design approaches and operating procedures will be required to achieve the functional requirements of a dispatchable plant.

  Testing of individual components and the integrated system along with vendor engagement are key to advance the technology maturity for this design.

- First of a Kind Integration

  The integration of all the identified low TRL technologies on a system level is a key risk to the project. This risk is split two ways. Firstly, the FOAK integration of a CCGT plant and a post-combustion carbon capture plant which results in scale -up of a number of the technologies across the entire project larger than any current CCS projects. Secondly, the integration of several CO_2 emission sources from two UK industrial clusters into a single transportation and storage facility. The majority of CCS projects or operational facilities to date have involved a single or a couple of sources going to a single store.

- Subsurface Safety Valve (SSSV)

  Current SSSVs on the market are qualified to -5oC. In a CO_2 injection well in dense and liquid phases in particular, depressurization of the well above a closed safety valve (e.g. rapid bleed-off, catastrophic loss of Christmas tree) would result in the rapid CO_2 depressurisation and pressure drops and the resulting cold pulse moving down the tubing to the SSSV. The SSSV in these cases would potentially need to be qualified to temperatures of -30oC or lower to maintain integrity in this event and prevent backflow of CO_2 from the reservoir.

2.7 Discounted Technology Risks

The project has considered several technologies that could pose a risk to the project. However, these have been discounted as either not worth pursuing as the technology is too underdeveloped or the risk initially identified is no longer deemed credible. The following technologies and risks were assessed and eventually ruled out of the technology plan:

1. Exhaust gas recirculation

This technology takes a portion of the exhaust gas and recirculates it back upstream of the compressor on the gas turbine in order to increase the CO2 content of the flue gas and significantly reduce gas flow rates thereby reducing absorber footprint. This technology will not be progressed further in the project due to the low technology readiness level (TRL3) and due to the complexity, it would add to the power generation plant design.

2. The use of exotic materials and welding techniques on the Heat recovery steam generator

This technology risk was initially considered possible due to the higher firing temperature in the H class CCGT which could affect the materials in the HRSG downstream. This risk was discounted as it was clarified that the H class CCGTs are more efficient and therefore the exhaust gases are colder than the F Class CCGTs. This technology risk was removed from the technology plan.

3. Selective Catalytic Reduction

Initially this was considered a risk due to potential scale up risks and the impact of thermal cycling. However selective catalytic reduction has now been removed from the technology plan as the technology is a proven TRL 7 with several operational CCGT power plants using SCR technology in Europe i.e. Irsching power plant in Germany.

4. Autonomous monitoring for seabed

This technology will allow the project to monitor the seabed for leakage and any water properties changes. Initially this was deemed a technology stretch as the available technology had not been tested by major companies and been qualified. However, since then this has been proven to be a TRL 6/7 and has been utilised by Sonardyne for CO2 outcrop monitoring. Further work required will be to tune the equipment to the NZT environment which will be progressed with the project’s environmental monitoring scope.

5. Pipeline leak detection on the gathering network

This was initially added as a technology risk due to lack of information on low pressure leakage detection. However, this has now been removed from the technology plan as fibre optic measuring equipment have been identified as a suitable CO2 detection for the gathering network.

6. Rig and LWIV Qualification for CO2 intervention and in-fill drilling

This technology risk was initially added to the technology plan to assess the suitability of drilling rigs or intervention vessels to deal with CO2 instead of hydrocarbons. CO2 suitable equipment has since been identified but must be tailored to individual rigs as part of rig intake program. This is no longer determined a technology risk therefore has been added to the project risks instead.

7. Permanently Installed Pressure Monitoring Sensor behind Casing

This technology enables pressure sensors to be permanently installed behind the well barrier without compromising integrity or well design. This has been removed from the technology plan as the TRL has been confirmed to be available from vendors as a TRL 6. bp also have applied this technology in ACG for overburden monitoring which is the same requirement for NZT. The decision to use this technology will be further progressed as a Tier 3 decision.

8. Hermetically Sealed Compact Compressors (HSCC)

HSCCs were not considered a feasible technology at this stage of the project. They have several advantages compared to conventional centrifugal compressors however, considering the power driver limitation (approximately 11 – 14 MW) and the requirement of dry CO2, it is unlikely that this technology will be the most suitable for the project. If feasible, HSCC technology may be considered at the next phase of the project as a possible design optimisation.

9. CO2 gas phase fiscal metering

CO2 gas phase metering was initially on the technology plan however is now considered TRL 6 due to feedback from ACTL, responses from 3 suppliers that they have successfully deployed CO2 metering skids and information from the North Sea Flow Measurement workshop where multiple technologies were considered feasible for CO2 metering.

2.8 Qualification Costs

Technology qualification costs will be further developed in line with the project contracting strategy.

3.0 Full Chain

3.1 Functional Technology Summary

The Project has identified two full chain technology risks that require a qualification roadmap prior to Execute. The basis of design for the Power and Capture plant is to run in dispatchable mode to modulate the power demand of the national grid in conjunction with renewable power sources. This poses several technology risks to the project in particular to the capture facility and gas processing units.

The second full chain risk relates to the first of a kind nature of the project. NZT will be the world's first CCGT plant integrated with a post-combustion carbon capture plant. It will also be the first decarbonised industrial hub with the CO2 gathering network running through Teesside. The project recognises that a first of a kind integration of the full chain project requires a technology risk review and qualification plan.

3.2 Technology Opportunities

	Technology	TRL	Qualifying Party
1	Full chain dispatchability	3	Supplier led
2	FOAK Integration	3	Supplier led

Table 1 Full Chain Enabling Technology Risks

3.3 Cumulative Technology Management

Qualification of the full chain technologies will be closely linked with the Contracting Strategy which will be further developed during Optimise. Key technology issues on Dispatchability and Integration will be included in a study carried out by SNC Lavalin to support technology qualification and development.

4.0 Facilities

4.1 Functional Technology Summary

The current facilities scope comprises nine enabling Serial #001 technologies as listed in Section 4.2. These are typical reflecting the First-of-a-kind (FOAK) nature of this project and initial engagement with the suppliers has begun to understand current proposed design and potential opportunities to mitigate technology stretches. Further optimisation and qualification of these Serial #001 technologies is closely linked with the project Contracting strategy and will be developed further in Optimise.

4.2 Technology Opportunities

Number	Technology	TRL	Qualifying Party
3	Flue gas diverter	4	Supplier led
4	Flue Gas Blower	4	Supplier led
5	Use of large size Absorber and Quencher unit	5	Supplier led
6	Solvent scale up	4 to 7	Supplier led
7	O2 removal	3	Supplier led
8	Ductile fracture propagation on offshore pipelines	4	I&E
9	Corrosion mechanisms in gathering network and offshore pipeline	5	I&E
10	Qualification of non-metallic materials with dense phase CO2	5	I&E
11	CO2 Detection Onsite	4	NPL
12	All electric subsea control	5	Supplier led
13	H Class CCGT	5	Supplier led

Table 2 NZT Enabling Facilities Technology Risks

4.3 Cumulative Technology Management

Qualification of the key Serial #001 technologies is closely linked with the Contracting Strategy which will be further developed during Optimise. Key technology related questions will be included within proposed supplier engagement processes (e.g. RFI, RFP) to support supplier selection as well as technology qualification and development.

5.0 Wells

5.1 Functional Technology Summary

The wells scope includes one Serial #001 enabling technology (SSSV for CO2 injection wells) to support robust concept design. A key enhancing Serial #001 technology (DAS) is also included to support reservoir monitoring and further mitigate key project risks around store performance.

5.2 Technology Opportunities

Number	Technology	TRL	Enhancing / Enabling	Qualifying Party
14	Subsurface Safety Valve SSSV for CO2 Injection wells	3	Enabling	Watching brief on Porthos project (NL) as initial work already started. Evaluating potential for a JIP to develop a suitable valve

Table 3 NZT Wells Enabling Technology Risks

Number	Technology	TRL	Enhancing / Enabling	Qualifying Party
15	Distributed Acoustic Sensing (DAS) in subsea wells	3	Enhancing	Supplier-led.

Table 4 NZT Wells Enhancing Technology Risks

5.3 Cumulative Technology Management

The key strategy to manage qualification for Serial #001 technologies is to work with other planned CCUS projects through JIPs for the SSSV qualification. Qualification of subsea DAS is being led through industry solutions and other BP projects in GoM also exploring use of this technology.

6.0 Subsurface

6.1 Functional Technology Summary

There are a number of Subsurface enhancing technologies identified to further support monitoring during operation and post-closure (MMV plan).

6.2 Technology Opportunities

Number	Technology	TRL	Qualifying Party
16	In-well gravity survey	3	Supplier-led
17	Optimized 2DHR seismic for 4D monitoring	5	Supplier-led
18	Permanent Landers for Seabed monitoring	6	Supplier-led

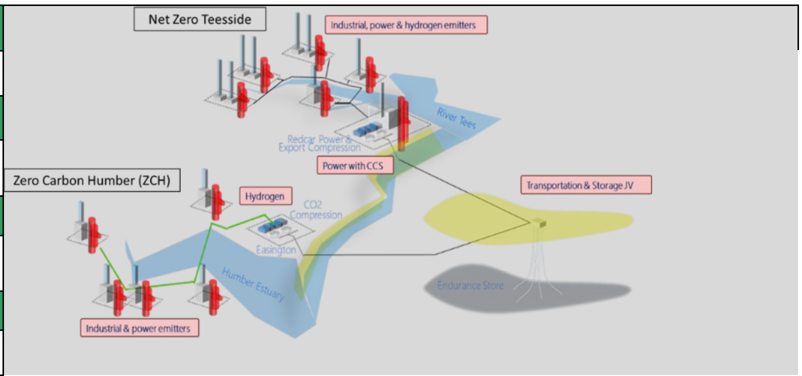
Table 5 NZT Subsurface Enhancing Technology Risks

Annex A Technology '2-pagers' (Strictly Confidential – Contains Commercially Sensitive Information – FOIA/FOI(S)A Exempt)

A.1 Full chain Dispatchable Technology 2 pager

Facilities	Full Chain Dispatchability
Date: 08/02/21	
Current TRL: 3	
Reference Case:	
Enabling	

SPA	
Independent Verification SME	
Qualifying Party	
Supplier Led	
Qualification Cost Estimate	



Technology Description

A dispatchable gas fired with post combustion CCS plant is one that can be turned on or off or where the power output can be adjusted in according to market demands and to support intermittency of renewable energy (wind, solar). This is different to a baseload plant which runs continuously.

CCGT power stations are proven to operate in dispatchable mode. However, the only two other large-scale post combustion capture facilities operate in baseload design. Various options (e.g. amine storage, auxiliary boiler, external heat supply, etc.) have been identified through desktop studies to enable a dispatchable design of the plant. However, the integration of a power station and post combustion CCUS plant with a dispatchable design has not been proven at scale.

Two key technology areas that need to be addressed are:

Running in dispatchable mode increases risk of thermal fatigue due to more frequent start-ups within the system and may also require more advanced emission control systems.

New design approaches and operating procedures will be required to achieve the functional requirements of a dispatchable plant.

Testing of individual components and the integrated system along with vendor engagement are key to advance the technology maturity for this design.

Value Proposition

Dispatchable gas with CCS supports back up of intermittent renewables such as solar and wind, enabling decarbonization of the UK power sector. Power system modelling by Baringa (Ref) demonstrates higher value to the energy system from a dispatchable design concept relative to a baseload design concept.

Relevant bp / Industry Experience

Extensive full chain modelling carried out as part of Shell Peterhead project for gas CCGT with post combustion CCUS facilities.

Current Status

Various desktop feasibility studies supported by simulation modelling has been carried out to prove the dispatchable concept. The IEA GHG report and Peterhead project are two key sources.

Some small-scale pilot plant testing carried out at Imperial College carbon capture pilot plant and ACT facilities (UKCCSRC) at University of Sheffield.

Qualification / TRL Milestones	Dates

<table>
<tr><td colspan="2">Develop a project position on minimum testing/qualification requirement for dispatchable operations.

Engagement with vendors to understand experience of dispatchable operation and identify knowledge gaps

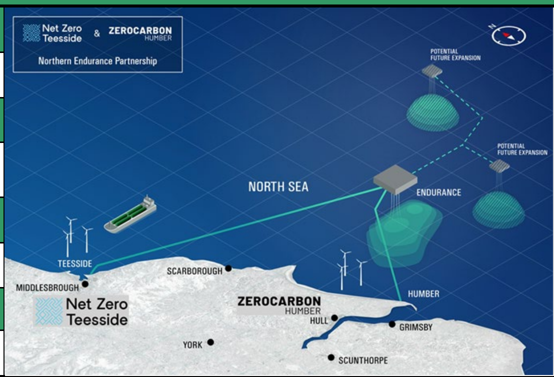
3rd party engineering contract to assess current technology readiness of dispatchable operations and propose a qualification roadmap.</td><td>Q2 2021

Q2 2021

Q2 2021</td></tr>
<tr><th>Key Risks</th><th colspan="2">Mitigations</th></tr>
<tr><td>Insufficient testing or qualification leads to inability of plant to meet functional specifications for dispatchable design. Loss of revenue relative to forecasted performance impacting deployment of additional gas with CCUS facilities to support low cost decarbonization.</td><td colspan="2">Early market engagement and development of testing and qualification plans based on identified gaps in supplier proposals to provide sufficient qualification time.</td></tr>
<tr><td>Dispatchable operation may add thermal stress to the key components in capture plant from potentially frequent and large swings in temperature. This may require use of exotic materials or specialist welding techniques to mitigate this.</td><td colspan="2">Full chain simulation including dynamic modelling to address process simulation requirements over the project lifecycle to model transient operations, optimize and test integrated design.</td></tr>
<tr><th colspan="3">Contingency Plan</th></tr>
<tr><td colspan="3">Consider addressing potential risks through commercial contracts.</td></tr>
<tr><th colspan="3">Key Documents</th></tr>
<tr><td colspan="3">1. Operating flexibility of power plants with CCS, IEAGHG, 2012/6,

2. Ceccarelli et al, Flexibility of low-CO2 gas power plants: Integration of the CO2 capture unit with CCGT operation, 2014.</td></tr>
</table>

A.2 Full Chain First of a Kind Integration

Facilities	FOAK Integration	
Date: 12/02/21		
Current TRL: 3		
Reference Case:		
Enabling		
SPA		
Independent Verification SME		
Qualifying Party		
FEED contractor		
Qualification Cost Estimate		
Technology Description		

The project aim is to deliver the world's first clean gas fired power station with carbon capture and storage and, decarbonize industrial clusters in Teesside and Humberside. A key full chain risk to the project is the integration of all the identified low TRL technologies including scale-up and dispatchable operation risks on a system level. Three key aspects have been identified for this risk:

1.Integration of different emitters and clusters - The project will need to integrate several CO2 emission sources from different types of industries (power, hydrogen, industries, etc.) across two separate UK industrial clusters into a single transportation and storage facility. In addition, the combined volumes will be sequestered over multiple stores with a network of up to 27 wells across 5 stores. The majority of CCS projects or operational facilities to date have involved a single or couple of sources going to a single store and this project will therefore create a first of a kind, integrated CO2 network system. They key challenge to integration are expected to be designing the system to enable varying flows and flexibility for the emitters while maintaining the transportation and storage design and operating envelope and keeping the system in a single phase. No specific technology challenges have been identified to achieve this integration to date.

2. Integrating a number of scaled -up FOAK technologies across the chain. In particular scale up of the flow path and major equipment between the H-class CCGT and the capture plant regenerator has been identified as a scale up of 2.5 – 3 times that of existing analogues. In addition to managing equipment and component level scale up risks; the overall system integration and combined operability of the various components also needs to be considered.

3. Applicability and validation of models and testing done at smaller scales to the project concept scale and integration. Two key considerations are predicting CO2 fluid behaviour for the expected compositions from the various emitters and lack of operational or testing data to validate simulation model predictions.

Understanding how the processes will integrate throughout the entire plant is key to executing and operating the project within the projected timescale and reducing the unknown risks that the project may face.

Value Proposition

A deep delve into the potential risks with FOAK integration on the full chain will highlight any unknown project risks that may result in delays to the project.

Relevant BP / Industry Experience

This is a FOAK project however there are similar coal fired power plants integrated to post combustion capture plants i.e. Boundary dam and Petronova. BP also has previous experience in operating gas and oil network systems in the North Sea (e.g. CATS, Forties Pipeline, etc.) and Alaska. In addition, there are several CO2 pipeline networks running in North America.

bp Technology Alignment

Current alignment with in the I&E Process Team on CO2 equation of state modelling to feed into the full-scale simulation.

Current Status	
Qualification / TRL Milestones	**Dates**
3rd party engineering contractor to assess current technology readiness, highlight key risks, and propose qualification plan for full chain integration.	Q2 2021
Key Risks	**Mitigations**
Underperformance of the full chain due to lack of integration between components resulting in loss of clean power export or CO2 injection rates.	Development of full chain philosophies and studies.
Integration faults between components identified during commissioning leading to project start-up delays.	Early development of testing and commissioning procedures to identify component interactions.
Unstable CO2 equations of state modelling resulting in inaccuracies in project design.	Full chain simulation including dynamic modelling to address process simulation requirements over the project lifecycle to model transient operations, optimize and test integrated design.
Contingency Plan	
n/a	
Key Documents	
n/a	

A.3 Flue Gas Diverter Technology 2-pager

Facilities	Flue Gas Diverter	
Date: 17/03/2020		
Current TRL: 4		
Reference Case:		
Enabling		

SPA	
Independent Verification SME	
Qualifying Party	
Supplier led	
Qualification Cost Estimate	

Technology Description

There are two outlets for the flue gas exiting the HRSG; direct to the atmosphere through the HRSG stack or feed forward to the capture plant and exiting at the top absorber. Flue gas feeds forward to the capture plant during normal operation and through the HRSG if the forward route is unavailable, for example due to a trip. There must be an escape route for the flue gas at any time otherwise pressure build up in the system will trip the turbine.

An approach to ensure an escape route is always available is to have a diverter which is able to open/close to control the direction of the flue gas. These diverters can be used in a low leak or zero leak application. Diverter dampers are available in three configurations: louver, flap style, and Tee. The use of a diverter is proposed for the NZT project. The diverter however needs to respond quickly enough to prevent back pressure build up to the GT in the event of a blockage of the forward escape route

Value Proposition

The use of a diverter prevents air ingress into the capture plant resulting in:

Higher effective capture rate since the entire flue gas is diverted to the capture plant
Lower solvent degradation and hence lower make up rate
Less frequent waste disposal of spent amine and

Lower oxygen levels in the product CO_2

Relevant BP / Industry Experience

Diverters on CHP plants at refineries/ mid-stream operations. Existing power plants
Current Status
Diverters are commonly used in isolation/bypass applications such as waste heat recovery steam generators (HRSG) on gas turbine systems. The scale of application for NZT is however beyond what is currently in operation anywhere in the world. The NZT flue gas duct size is expected to be circa 7 x 7 m. In terms of scale, Boundary Dam is the most relevant large-scale post combustion carbon capture plants in operation, but it is in a coal plant service. Boundary Dam diverts the entire flue gas from a 140 MW plant train. The flue gas duct is ~ 6x6m This technology is classified as TRL 5 to reflect the scaling up and change of service (from coal to gas flue gas) required for the proposed application Two suppliers have proposed designs: one a guillotine gate type and the other a biplane style blade design. Both suppliers provide refences for by-pass systems and diverter dampers however both have no experience with CCSU application or H class CCGT machines. Further work with suppliers will be required to understand the availability and maintenance for both normal and dispatchable operation.

Qualification / TRL Milestones	Dates
EPC contractor to develop qualification plan with suppliers	Within Define

Key Risks	Mitigations
Response time Reliability Manufacturing Supply chain Thermal Cycling compounded due to dispatchability Scale up risks associated to sealing efficiency General service conditions Sealing cooling flows	Early qualification if required CFD modelling Supplier Engagement Structural review

Contingency Plan
To be defined following risk workshop.

Key Documents

1. Tier 2 Decision paper - NS051-PM-DEP-000-00031 Flue gas Diverter

2. Mott Macdonald: By-pass Dampers for Carbon Capture Jan 2021

A.4 Flue Gas Blower Technology 2-pager

Facilities	Flue Gas Blower	
Date: 29/09/2020		
Current TRL: 4-5		
Reference Case:		

Enabling	
SPA	
Independent Verification SME	
Qualifying Party	
Supplier led	
Qualification Cost Estimate	

Technology Description
The current base case design is to run the CCGT at atmospheric pressure therefore to overcome the pressure drop across the absorber column, NZT will require a Flue Gas Blower capable of delivering the required pressures. Due to differences in CO2 concentration in the flue gas, flue gas volume for NZT will be about 2.5 – 3 times Petra Nova or Boundary Dam. This is reflected in the size of Blower required. The project may have to consider using multiple blower trains to ensure the flue gas pressure is adequate for the absorber.
Value Proposition
Blowers are required to overcome pressure drops across the absorber.
Relevant BP / Industry Experience
Blowers are used within downstream BP. Acon project to use multiple blowers to collate flue gas to a central plant.
BP Technology Alignment
Require references from downstream and petrochemicals.
Current Status
Currently the biggest blowers on the market offer a flow rate around 800 to 1500m3/s, NZT reference case is to use a single blower ~10 to 15% larger to meet the flue gas supply rate. For some suppliers they would propose 2 x 50% units to meet NZT requirements. Majority of blowers of the scale required for NZT are used in coal fired power plants. Further work with suppliers will be required to understand the availability and maintenance for both normal and dispatchable operation.

Qualification / TRL Milestones	Dates

Final Configuration and selection to correspond to selected Licensor proposed design.	Within Define

Key Risks	Mitigations
Experience limitations based on the following criteria: Power range Fan Diameter vs speed Bearings and Lubrication Temperature range ambient to 140degC Flow control method Motor type and size Rotordynamics Configuration and layout Thermal Cycling compounded due to dispatchability	Obtain reference list from established suppliers for similar applications and configuration Perform technical review of supplier designs including lateral analysis, CFD, casing modal and thermal analysis Use of force lube systems and sleeve bearings Proven control method of flow control on similar duties Proven motor type and size references Review operating procedures for hot and cold starting including limitations on electrical and mechanical system

Contingency Plan
Multiple blower trains to match current experience levels.

Key Documents
1. NS051-ME-TEC-000-00001 – Flue Gas Fans Technical Note

A.5 Use of Large Size Absorber and Quencher Unit Technology 2-pager

Facilities	Use of large size Absorber and Quencher unit	
Date: 17/03/2020		
Current TRL: 5		
Reference Case:		

Enabling	
SPA	
Independent Verification SME	
Qualifying Party	
Supplier led	
Qualification Cost Estimate	

Technology Description

The flue gas volume for NZT will be about 2.5 to 3 times larger than any commercially operated

post combustion capture plant operated today due to the type and scale of combustion on the project. This is reflected in the absorber and quencher dimensions where the increase in cross-sectional area will also be around 2.5 to 3 times larger than similar CCS plants like Boundary damn and Petra Nova. Due to the significant increase in column cross sectional area, both vessels may face issues, such as:

Operating the absorber with even gas and liquid distribution may be challenging when considering a single absorber structure.
The ability to construct the required size vessels as a single unit needs to be verified
Potential for cooling performance issues with a large quench tower and resulting in lower CO_2 absorption efficiency and increased flue gas contaminants such as ammonia and NOx

Value Proposition

Having a single absorber (even with multiple cells) and a single quencher structure, will:

- Reduced capital cost
- Reduced plot area
- Reduce the overall liquid piping and gas ducting which will also assist to reduce capital cost, footprint and overall complexity

Relevant BP / Industry Experience	
• Large oil refinery fractionation units • Amine units in gas processing plants • Carbon capture plants • Quench towers are used widely in industry	
bp Technology Alignment	
n/a	
Current Status	
Absorbers: Early correspondence with internals vendors has advised their capability to factory acceptance test a liquid distributor of circa 12m diameter.	
Qualification / TRL Milestones	**Dates**
Engagement with individual licensors with respect to internals and distributor sizes Engage with suppliers to evaluate limits of internals and distributor sizes CFD modelling to verify gas distribution Engagement with individual licensors and specialist Contractors to review method of construction and constructability.	During define in line with proposed contracting strategy
Key Risks	**Mitigations**

Gas and/or liquid maldistribution resulting in CO2 theoretical capture efficiency not being achieved at either design throughput or turndown. Construction methods of such large vessels are not proven in the industry Thermal Cycling compounded due to dispatchability Gas distribution issues within the Quencher which may result in poor performance Higher contaminant carryover due to maldistribution within the Quencher	Use of multiple gravity (trough) type liquid distributors that have been proven in the industry, and that can be factory performance tested Single absorber is designed with sufficient pressure drop to ensure adequate distribution of the gas Multiple cell absorber in a single structure with control of gas flow to each CFD modelling to ensure adequate gas distribution Constructability workshop
Contingency Plan	
Multiple quencher and absorber trains to decrease required vessel dimensions however it should be noted this will bring several challenges to the design such as achieving even flue gas split flow distribution.	
Key Documents	
1. NS051-DM-DEP-000-00035_revA01 Absorber Scale up Decision paper	

A.6 Solvent Scale Up Risks Technology 2-pager

Facilities	Capture Solvent risks	
Date: 18/11/20		
Current TRL: 4 to 7		
Reference Case:		

Enabling	
SPA	
Independent Verification SME	
Qualifying Party	
Supplier led	
Qualification Cost Estimate	

Technology Description

Many of the carbon capture licensor technologies identified have been historically developed for coal -fired power stations. Performance of the solvent with composition and contaminants typical of a NGCC flue gas application has therefore been identified as a key technology risk. Key risks include:

Increased degradation of the solvent in the presence of high O2, NOx and CO typical of a gas fired flue gas compared to a coal fired flue gas.

Potential for increased oxidative and thermal degradation of solvent in NGCC flue gas applications resulting in airborne emissions of toxic, volatile degradation products such as ammonia and N-amines from the absorber stack that may adversely impact sensitive local environmental receptors if not adequately mitigated. Minimising solvent degradation and resulting atmospheric emissions is therefore a key driver for the project. The impact of solvent degradation and atmospheric emissions is enhanced at large scale applications relative to small-scale testing. Demonstration of emission testing at a large enough (prototype scale) scale was therefore considered as an important parameter.

Value Proposition

Addressing the scale up risks associated with the Solvent will:

- Reduce degradation of the solvent
- Reduce toxic emissions

Relevant BP / Industry Experience	
There are relatively comparable large-scale post combustion carbon capture plants however they are used for coal fired power plant which have higher CO2 concentrated flue gas therefore different solvent chemistry will apply.	
Current Status	
Small scale testing at TCM (Technology Centre Mongstad) and similar testing facilities or licensor pilot plants has been carried out for NGCC flue gas.	
Qualification / TRL Milestones	**Dates**
Review lab/ pilot plant testing experience as part of licensor pre-qualification and contracting strategy. Review potential for independent additional qualification following licensor selection.	Q4 2021

Key Risks	Mitigations
Solvent degradation Development of toxic emissions	Evaluate and select licensors based on relevant testing experience and solvent degradation and emissions data Undertake further testing if deemed necessary after licensor selection Give consideration to predictability even it means lower capture rate and higher parasitic loads in commercial agreements. Capture plant material selection to consider potential for higher corrosion rates. Review solvent management strategy including reclamation technology.

Contingency Plan
Licensor performance guarantees including emissions guarantees. Keep a watching brief on open-access technologies and engage more actively with relevant forums within the Stakeholder Management Plan to demonstrate willingness to work with academia, the Environment Agency, and other stakeholders for future capture plants.
Key Documents

A.7 O2 Removal Technology 2-pager

Facilities	O2 removal technology	
Date: 18/11/20		
Current TRL: 3		
Reference Case:		

Enabling	
SPA	
Independent Verification SME	
Qualifying Party	
Supplier led	
Qualification Cost Estimate	

Technology Description

The flue gas from the CCGT plant will contain around 10.7 mol% oxygen and about 4.8% CO2 (wet basis, uncorrected for oxygen). A small quantity of oxygen will be absorbed into the amine and subsequently released in the amine regenerator along with the absorbed CO2. The CO2 product leaving the amine regenerator contains approximately 20 ppmv oxygen. The CO2 product specification to meet metallurgy requirements of the wells is <10 ppmv oxygen, therefore an oxygen removal process is required. This oxygen removal unit consists of a fixed bed reactor containing a platinum catalyst. Hydrogen is added at a stoichiometric ratio of 5:1. The reaction takes place at 150 degC and this temperature is achieved by locating the reactor downstream of a compressor inter-stage, thereby using the heat of compression.

Value Proposition

If O2 is not removed from the product CO2 to the required specification it results in corrosion of the well metallurgy at the brine interface. The option of upgrading the metallurgy to avoid the requirement for an O2 removal unit was evaluated, but this was not economic.

Relevant BP / Industry Experience

Johnson Matthey has experience of using the same technology for CO2 purification in urea plants.

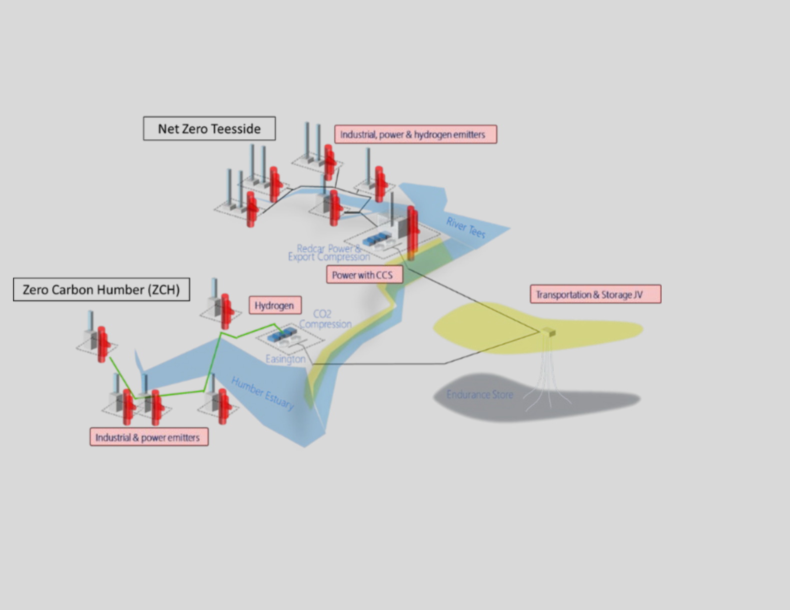
Current Status

Qualification / TRL Milestones	Dates
Genesis to propose qualification plan and engage market for references.	Q2 2021

Key Risks	Mitigations

Amine and/or other contaminants in the feed to the oxygen removal unit Impact of operating the O2 removal unit in dispatchable mode and cycling of temperature and potentially pressure	Upgrade metallurgy of wells
Contingency Plan	
n/a	
Key Documents	

A.8 Ductile Fracture Propagation on Offshore Pipelines Technology 2-pager

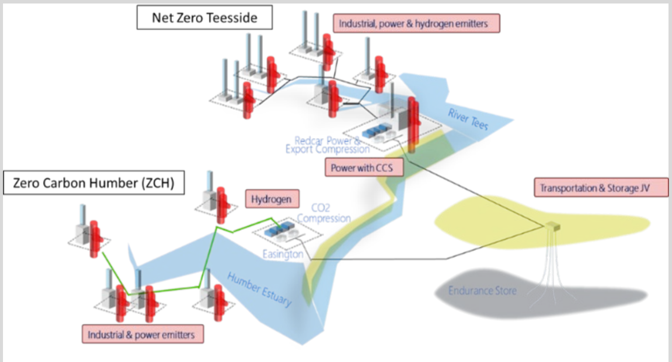
<table>
<tr><td>Facilities</td><td rowspan="4">Ductile fracture propagation on offshore pipelines</td><td rowspan="4"></td></tr>
<tr><td>Date: 15/10/20</td></tr>
<tr><td>Current TRL: 4</td></tr>
<tr><td>Reference Case:</td></tr>
<tr><td colspan="3">Enabling</td></tr>
<tr><td>SPA</td><td colspan="2" rowspan="8">
</td></tr>
<tr><td></td></tr>
<tr><td>Independent Verification SME</td></tr>
<tr><td></td></tr>
<tr><td>Qualifying Party</td></tr>
<tr><td>UEC</td></tr>
<tr><td>Qualification Cost Estimate</td></tr>
<tr><td></td></tr>
<tr><td colspan="3">Technology Description</td></tr>
<tr><td colspan="3">Material selection is important to ensure the system is compatible with the typology of service, including compatibility with the environments, both internal and external, to avoid failures and leakages during operation. BP has extensive experience with transporting hydrocarbons however knowledge of CO2 transportation needs improvement. Pipeline material selection is not a technology risk but there is currently a knowledge gap within BP and industry to ensure all the degradation mechanisms linked to the transportation of CO2 (low pressure and dense phase) are considered and addressed to provide a safe infrastructure. This technology plan will cover the potential for Ductile fracture propagation in the offshore pipeline for dense phase CO2 transportation.</td></tr>
<tr><td colspan="3">Value Proposition</td></tr>
<tr><td colspan="3">Ensuring the correct material design is chosen will:
• Avoid failures & leakages</td></tr>
</table>

• Reduce downturns • Properly manage and potentially reduce maintenance required	
Relevant BP / Industry Experience	
BP/industry currently lack experience with Dense CO2.	
Current Status	
Due to the lack of industry knowledge the key failure mechanisms are still not fully understood or recognized, further work is required to identify the key risks this poses to the project.	
Qualification / TRL Milestones	**Dates**
I&E initiative to address ductile crack propagation issues (correction factors, toughness etc)	Q3 2021
Key Risks	**Mitigations**
Ductile crack propagation (Specifically offshore pipeline due to dense phase CO2)	Correct material selection / design Use of crack arrestors
Contingency Plan	
n/a	
Key Documents	

A.9 Corrosion Mechanisms in Gathering Network and Offshore Pipeline Technology 2-pager

Facilities	Corrosion mechanisms in gathering network and offshore pipeline due to unknown properties of Product CO2
Date: 16/11/20	
Current TRL: 5	
Reference Case:	

Enabling	
SPA	
Independent Verification SME	
Geoff Evans	
Qualifying Party	
UEC	
Qualification Cost Estimate	



Technology Description
Material selection is important to ensure the system is compatible with the typology of service, including compatibility with the environments, both internal and external, to avoid failures and leakages during operation. BP has extensive experience with transporting hydrocarbons however knowledge of CO2 transportation needs improvement. Pipeline material selection is not a technology risk but there is currently a knowledge gap within BP and industry to ensure all the degradation mechanisms linked to the transportation of CO2 (low pressure and dense phase) are considered and addressed to provide a safe infrastructure. This technology plan will cover: 1. Offshore pipeline for dense phase CO2 transportation - Potential Corrosion due to a not consistent CO2 composition (higher levels of contaminants, i.e. NOx, SOx, O2, H2O etc). - Potential Corrosion due to an unknown mechanism.

<table>
<tr><td colspan="3">2. CO_2 Gather network

- Potential Corrosion due to a not consistent CO_2 composition (higher levels of contaminants, i.e. NOx, SOx, O_2, H_2O etc).</td></tr>
<tr><td colspan="3">Value Proposition</td></tr>
<tr><td colspan="3">Ensuring the correct material is chosen will:
Avoid failures & leakages
Reduce downturns
Properly manage and potentially reduce maintenance required</td></tr>
<tr><td colspan="3">Relevant BP / Industry Experience</td></tr>
<tr><td colspan="3">BP have an established material corrosion program however lack experience with Dense CO_2, this is also the case industry wide.</td></tr>
<tr><td colspan="3">bp Technology Alignment</td></tr>
<tr><td colspan="3">UEC to develop BP knowledge of dense CO_2 systems</td></tr>
<tr><td colspan="3">Current Status</td></tr>
<tr><td colspan="3">Due to the lack of industry knowledge the key failure mechanisms are still not fully understood or recognized, further work is required to identify the key risks this poses to the project.</td></tr>
<tr><td colspan="2">Qualification / TRL Milestones</td><td>Dates</td></tr>
<tr><td colspan="2">Material testing scope to be issued with FEED RFPs

I&E team to provide a guidance note on CO_2 equation of state</td><td>Q2 2021

Q2 2021</td></tr>
<tr><td>Key Risks</td><td colspan="2">Mitigations</td></tr>
<tr><td>Corrosion due to unexpected degradation mechanism, e.g. impact of contaminants i.e. O_2, high water cut</td><td colspan="2">Correct material selection

Reliable corrosion monitoring systems

Inspection</td></tr>
<tr><td colspan="3">Contingency Plan</td></tr>
</table>

n/a
Key Documents

A.10 Qualification of Non-metallic Materials with Dense Phase CO2 Technology 2-pager

Facilities	Qualification of non-metallic materials with dense phase CO2	
Date: 21/10/20		
Current TRL: 5		
Reference Case:		
Enabling		
SPA		
Independent Verification SME		
Qualifying Party		
I&E		
Qualification Cost Estimate		
TBC		

Technology Description
When transporting the CO2 offshore it will be compressed into a dense phase which can pose a risk to the non-metallic material it will be in contact with i.e. soft goods in valves, polymers on pipeline Pigs, elastomer seals etc. Many polymers when exposed to CO2 will tend to swell due to diffusion. This may change the properties of the material and cause degradation over time. Due to the lack of industry knowledge the key failure mechanisms are still not fully understood or recognized, further work is required to identify the key risks this poses to the project.

Value Proposition

Ensuring correct material selection will:

- Avoid failures & leakages
- Reduce downturns
- Properly manage and potentially reduce maintenance required

Relevant bp / Industry Experience	
bp have experience with degradation on non-metallic materials due to high pressure natural gas which may act similarly to CO_2.	
bp Technology Alignment	
I&E to develop BP knowledge of dense CO_2 systems	
Current Status	
Due to the lack of industry knowledge the key failure mechanisms are still not fully understood or recognized, further work is required to identify the key risks this poses to the project.	
Qualification / TRL Milestones	**Dates**
• Feed contractor to identify all non-metallics for project and qualify individually. • Feed contractor to document the required testing recommended by industry standards	Define Stage
Key Risks	**Mitigations**
Lamination of non-metallic materials Hardening of non-metallic materials Not recognizing potential failure mechanisms	Correct material selection Developing BP knowledge of dense CO_2 system
Contingency Plan	
n/a	
Key Documents	

A.11 CO2 Detection Onsite Technology 2-pager

Facilities	CO2 detection onsite	
Date: 23/10/23		
Current TRL: 4		
Reference Case:		

Enabling	
SPA	
Independent Verification SME	
Qualifying Party	
NPL	
Qualification Cost Estimate	
TBC	

Technology Description

CO2 detection will be essential to ensure the safety of personnel onsite. Currently there are several types of CO2 detection that could be used for NZT:

- Acoustic detection
- Thermal imaging camera
- Mist detection
- Laser Type CO2 detection
- Fibre optic temperature detection

Due to the relatively new application for these detectors, it may pose a challenge to ensure sufficient reliable coverage is possible to achieve onsite.

Value Proposition

- CO2 detection is required for:
- Personnel safety (CO2 can result in asphyxiation and toxicity)

<table>
<tr><td colspan="2">Reducing emissions</td></tr>
<tr><td colspan="2">Relevant BP / Industry Experience</td></tr>
<tr><td colspan="2">Qualification plan developed by Shell for the Peterhead CCS project.

CO2 detection is utilized for CCS plants such as Petra nova and Boundary dam.

bp has extensive experience for hydrocarbon detection.</td></tr>
<tr><td colspan="2">Current Status</td></tr>
<tr><td colspan="2">CO2 detection devices exist commercially but will require significant scale up and challenges may arise with developing a layout philosophy.</td></tr>
<tr><td>Qualification / TRL Milestones</td><td>Dates</td></tr>
<tr><td>Engineering FEED contractor to propose gas detection philosophy and qualification plan.</td><td>Within FEED</td></tr>
<tr><td>Key Risks</td><td>Mitigations</td></tr>
<tr><td>Uneconomic or insufficiently sensitive layout philosophy</td><td>NPL to prepare a technical layout philosophy</td></tr>
<tr><td colspan="2">Contingency Plan</td></tr>
<tr><td colspan="2">n/a</td></tr>
<tr><td colspan="2">Key Documents</td></tr>
<tr><td colspan="2"></td></tr>
</table>

A.12 All Electric Subsea Controls Technology 2-pager

Facilities	All electric subsea control	
Date: 20/03/2020		
Current TRL: 4/5		
Reference Case:		
Enabling		

SPA	
Independent Verification SME	
Qualifying Party	
Supplier Led	
Qualification Cost Estimate	

Technology Description

CAPEX and availability benefit from the removal of HPU, simplification of umbilical by removal of hydraulic lines. This simplification also reduces installation costs. OPEX benefit from the elimination of subsea hydraulic fluid usage and maintenance reduction.

Reduced lead time due to ease of manufacture and testing in comparison to tradition E/H umbilical systems.

Value Proposition

Simplify umbilical costs to simple power/ FO cable. Faster response time for valve functioning in a dispatchable mode. Enhanced condition monitoring.

Relevant BP / Industry Experience

Total have 3 producing wells with all electric systems, in operation since 2010 in Dutch North Sea. (K5F). The third completion has an electric downhole safety valve. (2016)

Implementation for electric actuators for choke & manifold duty on Atlantis Phase 3 & Matapal.

Total and Equinor have multiple actuators on choke and manifold valve duty both in the North Sea and West Africa.

bp Technology Alignment

This is a key GSS initiative for new Greenfield projects.

Funding has been approved with in bp to form a JIP to further qualify all electric subsea control.

Current Status	
All electric subsea control is currently the base case design for the project. Individual components of the system are proven however are under constant development, therefore require further qualification.	

Qualification / TRL Milestones	Dates
Watching industry brief on technology. Many projects are on the critical path prior to NEP reaching the execute stage. Engagement with NEP partners with experience in all electric subsea control	Within Define

Key Risks	Mitigations
Prove integrity of valve response time and fail safe for all electric controls.	Revert to umbilical with hydraulic line.

Contingency Plan
Traditional electro-Hydraulic umbilical however further work would be required to qualify dispatchable mode.

Key Documents
None

A.13 H Class CCGT Technology 2-Pager

Facilities	H Class CCGT	
Date: 17/03/2020		
Current TRL: 5		
Reference Case:		

Enabling	
SPA	
Independent Verification SME	
Qualifying Party	
Qualification Cost Estimate	

Technology Description

The H Class CCGTs are Combined Cycle Power Plants based on an H-class gas turbine, which represents the best-in-class heavy duty gas turbine available today on the market. ("H" is a nomenclature used by GE and adopted by Siemens but in the case of other OEM's generally refers to their latest class.) It is important to note that these machines are constantly evolving, and the H-class can generally be thought of as having a 1st generation (considered an Enabling technology risk) and a 2nd generation (considered an Enhancing technology risk).

"H class" is essentially defined as a firing temperature in excess of 2600°F (about 1426°C) and up to about 2900°F (1600°C) in the gas turbines combustion chamber.

The higher firing temperature results in higher efficiency which also results in slightly higher emissions of NOx. (or at least levels not able to be guaranteed as low as the previous F-class – 25ppm vs 15ppm).

Coincidentally, the class H CCGTs have been designed as larger machines as the OEM's assumed that economies of scale (lower $/kW) would be advantageous in the market. advanced design for burners (sequential combustion) and for generators cooling system (especially in the single-shaft configuration), an advanced design and an accurate selection of materials for heat recovery steam generators (HRSG) and installation of a selective catalytic reduction (SCR).

NZT are currently "assuming" the H class machines with the highest efficiency and the lowest l.c.o.e. These, at time of writing, have essentially had several units sold but none in actual operation.

Value Proposition

H-class turbines offer high efficiencies but the potential application for a dispatchable design will be further evaluated during optimize.

		Ansaldo		GE			MHPS		Siemen	
		GT26	GT36	9F.05	9HA.01	9HA.02	701-F	701-JAC 2015	8000H	9
Output at ISO (simple cycle)	MW	370	538	314	448	571	385	563	450	
Efficiency (Simple Cycle)	%	41.0	42.8	38.6	42.9	44.0	41.9	43.6	>41	
Exhaust flow	Kg/s	741	1,020	713	847	1,039	748	989	935	
Exhaust temperature	°C	625	621	632	648	640	630	649	630	
Dimensions GT only (m)	L x h x w	12.5 x 5 x 5.5	13.5 x 5.8 x 6.7	*12 x 5.5 x 5.5	*14.6 x 6.8 x 6.8	*14.6 x 6.8 x 6.8	**14.3 x 6.1 x 5.8	**16.7 x 6.9 x 6.5	12.5 x 5.5 x 5.5	13
Transport Weight	Tonnes	410	577	321	386	431	479	559	445	

Source: GT world Handbook 2020, *GT pro ** Website

The above table shows the four main OEM's and their 1st and 2nd generation GT's: the 1st generation range in output from about 370MW to 450MW and the 2nd generation from about 540MW to nearly 600MW.

This is a significant output range even once the class and generation has been chosen – which has an ongoing impact on the uncertainty and physical sizing of the "downstream" process.

To achieve the best performances in the electricity market, considering the increase in electricity generation from renewable sources, which are intermittent by their nature, and at the same time to guarantee security and flexibility, a modern power plant has to have the following functionality:

minimum turndown: extending low emissions operation to lower load levels, enabling reduced fuel consumption and lower total emissions at minimum loads; turndown capability also extends the available load range for operation, improving dispatchability and enabling greater participation in regulating reserve markets;

start-up time: ability of a CCGT to reach full load as soon as possible in response to sudden demand;

ramp rate: the rapid increasing or decreasing of plant load, to smoothly track changing load requirements without inducing undue thermal or mechanical stress in the equipment;

partial load efficiency: during periods of low electricity demand plants may be required to operate under part load conditions, maintaining as higher efficiency as possible; this can help to economically operate plants under a wide range of grid demand scenarios.

The integration with a CO2 capture system involves energy consumption (parasitic load) and a significant export of steam but has to be weighed against the strategy of keeping the standard CCGT package solution "standard". A particular element of low efficiency in any CCGT cycle is the steam turbine cycle which, in case of operation with continuous steam export, is definitely penalized in loss of MWe but is more efficient overall in terms of overall fuel use. The reduction in the size of the steam turbine, which improves, slightly, the overall efficiency needs to be assessed further considering, amongst things, ability to increase peak power and keeping the CCGT design as "standard" as possible – especially considering knock on impacts on the condenser and HRSG etc..

The emission characteristics of the machine guaranteed by the manufacturer and its degree of effectiveness in calibrating at different loads must, also, be highly taken into consideration. It will be extremely important that the machine manufacturer guarantees

Relevant BP / Industry Experience

The gas turbine power generation market has seen significant volatility in recent years due to climate change, changes in natural gas prices and the uncertain future of nuclear and coal power generation. In addition, the foreseeable demand for environmentally friendly power generation has convinced many power producers to integrate renewable generation capacities with environmentally clean gas-fired power plants.

There is a small, but experienced group of large gas turbine worldwide manufacturers: Mitsubishi Hitachi Power Systems (MHPS)*, Siemens, GE and Ansaldo Energia; recently deployed a new large turbine the South Korean company Doosan Heavy Industries & Construction (DHIC), but it it is newer to the market.

The best performances available on the market are: Max GT Net Output: 593MW; CCGT Efficiency: up to 64%; Minimum turndown: 25÷30%; Fast Start up: FSFL within 30 min; Fast ramp rate: 85MW/min; Emissions: down to 2 ppmvd with SCR, guaranteed down to 25 ppmvd without SCR. Not all the best performances appear in any one machine, but each gas turbine has specific peculiarities that favor some characteristics over the others.

It is also important to maximize procurement leverage by ensuring the price and contract (inc. performance guarantees) are negotiated in a competitive environment

Current Status

In the UK operating H-class turbines appear in only one plant (Baglan Bay Energy Park),(which was a now-discontinued, early steam-cooled variant). There is Keadby under development which is a 2nd generation Siemens (9000HL) – due to reach COD in 2022.

The world situation can be represented by main manufacturers data: as shown in the table below:

	(50Hz)		(60Hz)	
	Sold/Operating	Fleet Leader	Sold/Operating	Fleet Leader
Ansaldo GT36-S5	3/0	1st project COD expected Q1 2022		
Ansaldo GT36-S6			0/0	NA
GE 9HA.01	23/13	20,000FFH		
GE 9HA.02	14/0	First fire of lead project expected 2020		
GE 7HA.01			12/8	15,000FFH
GE 7HA.02			52/21	18,000FFH
GE 7HA.03			2/0	First test run not expected in 2021
MHPS 701 JAC	13/0	1st COD 2021		
MHPS 501 JAC			12/1	First project synchronised Q2 2020
MHPS 701J*	2/2	1st COD 2016		
MHPS 501J*			45/45	1st unit COD 2011
Siemens SGT5-8000H	47/41	22,000+ EBH		
Siemens SGT6-8000H			42/33	37,000+EBH
Siemens SGT5-9000HL	1/0	COD expected 2022		
Siemens SGT6-9000HL			4/0	1st project First fire achieved April 2020

This table shows both 50Hz and 60 Hz CCGT – and indicates that the 2nd generation units (circled blue) have no operational hours at present. By contrast the 1st generation units have some tens of units in operation – albeit still with limited operational hours (fleet leaders being GE and Siemens each with ~20,000 fired hours on their leading unit.

Qualification / TRL Milestones	Dates

• Obtain H Class reference cases operating in dispatchable mode • CCGT OEM-Contractor engagement • Partial load efficiency; minimum turndown capability • Steam Turbine (LP section size) • Maintenance interval to be reviewed as part of contracting and maintenance (LTSA) strategy to account for low TRL • Testing with OEMs after selection	During define in line with proposed contracting strategy

Key Risks	Mitigations
• Very limited H-fleet experience especially with the latest (2nd generation) versions • DLE/DLN combustion system acoustics and operability. • Hot gas path metallurgy and cooling performance. • Rotor construction, rotor-dynamics and undesirable vibrations. • Ability to reliably flex machine from start and stop is unproven and is highly challenging for large GTs irrespective of model • Increased maintenance cost relative to base loading plant • Steam cycle flexibility due to size of plant • Alternator experience • Starting technology • Thermal Cycling compounded due to dispatchability	Option 1 (pre-PO) • Alternative technology selection i.e. H-version 1 or F-class. Option 2 (schedule constrained) • Detailed technology design assessment and extended sub-component proving tests. • Extended testing and proving runs i.e. SATs. • Reliability runs (field based) • Increased spares holding (maintainability) • Improve CCGT configuration (sparing) • Follow industry experience as H-class operating

Contingency Plan
Use smaller, less efficient machines (e.g. F-class or H class 1st generation) with more proven operations.

Key Documents

1. GE’s HA Gas Turbine Fleet [website: https://www.ge.com/power/gas/gas-turbines/h-class]

2. Siemens [website: https://new.siemens.com/global/en/products/energy/power-generation/gas-turbines/sgt5-8000h.html]

3. MHPS [website: https://www.mhps.com/products/gasturbines/global-experience/index.html]

4. Power generation news – July 2018; Presentation of the first GT36 manufactured in Genoa.

A.14 Subsurface Safety Valve SSSV for CO2 Injection Wells Technology 2-pager

Wells	Subsurface Safety Valve SSSV for CO2 Injection Wells	bp
Date: 20/01/20		
Current TRL: 3		
Reference Case:		

Enabling	
SPA	
Independent Verification SME	
Qualifying Party	
Supplier Led	
Qualification Cost Estimate	

Technology Description

In conventional production and injection wells, downhole components are generally not exposed to temperatures below zero degC. In a CO2 injection well in dense and liquid phases in particular, depressurization of the well above a closed safety valve (e.g. rapid bleed-off, catastrophic loss of xmas tree) would result in the CO2 vaporising and the cold pulse moving down the tubing as the CO2 boils off.

With no external heat input, a theoretical minimum of -78 degC could be reached, although in practice geothermal heat from the surrounding sea and rock will mean the minimum temperature is higher than this. For a subsea application at the Endurance location, the seawater hydrostatic limits the minimum temperature to -55 degC.

This situation can also occur locally at the SSSV during SSSV testing or with a leaky valve.

There are no SSSVs on the market qualified to below -5 degC.

Value Proposition

A qualified SSSV will be required for the project – either to be fully operable at low temperatures or to maintain integrity at low temperatures having been operated closed earlier. In the latter case, the presumption would be that a workover would be required to replace it.

The qualification temperature will dependent on a subsea or NUI application – the former is less onerous as the CO2 can only boil off at hydrostatic pressure on the seabed – some 6 atm, as opposed to 1 atm at surface.

Relevant BP / Industry Experience

Development has begun with the Porthos project (NL), and a watching brief will be kept on this. In addition, negotiations are progressing with partner companies and external projects to form a JIP to develop a suitable valve.	
bp Technology Alignment	
JIP being controlled by GWO Technology group and Upstream Technology	
Current Status	
JIP under discussion, vendor workshop held with other operators	
Qualification / TRL Milestones	**Dates**
Another CO2 project has a requirement before NZT with identical temperature requirements, bp currently watching brief for this project.	Q2 2021
Key Risks	**Mitigations**
If first planned project use falls through, NZT will be first user and may have to maintain drive on qualification	
Contingency Plan	
NZT is part of SSSV work and so will be intimately involved and able to pursue should first user fall through. An alternative option could include the use of check valves instead of SSSVs, however this will also require a qualification plan to ensure integrity at the low temperatures required and may restrict intervention and production log access.	
Key Documents	

A.15 Distributed Acoustic Sensing (DAS) in Subsea Wells Technology 2-pager

Wells	Distributed Acoustic Sensing (DAS) in Subsea Wells	bp
Date: 03/02/20		
Current TRL: 4		
Reference Case:		

Enhancing	
SPA	
Independent Verification SME	
Qualifying Party	
Supplier Led	
Qualification Cost Estimate	

Technology Description
Distributed Acoustic Sensing (DAS) uses a downhole optical fibre strapped to the production or injection tubing to act as a distributed geophone system. Applications range from detecting sand production in wells from its acoustic signature, to monitoring the movement of fluids in the reservoir by changes in the acoustic response to induced seismic acoustic waves (VSP with air guns or vibro-truck).
Value Proposition
For a CO2 injection project, it is essential that the migration of the CO2 plume is monitored as injection continues over time, not only for reservoir management, but for regulatory compliance. Although other methods are available (such as 4-D seismic with a towed streamer array), this is more time consuming, less frequent, and more expensive.
Relevant BP / Industry Experience
BP has run DAS systems in dry tree wells in Azerbaijan, and has installed many DTS fibre systems around the world; however, the system has had limited use in a subsea environment primarily due to length of transmission fibre (current limit is ~100km) and alignment and longevity of the optical couplers between the tubing hanger and xmas tree. BP will be installing subsea DAS systems (fibre terminates above the production packer) in two GoM wells in 2021, and the technology is advancing rapidly due to interest from BP and other operators worldwide. Dry tree (land) system used in a monitoring well in the Ottway CCUS research facility in Australia.
bp Technology Alignment

<table>
<tr><td colspan="2">DAS is being considered by other BP subsea projects in GoM and Angola.</td></tr>
<tr><th colspan="2">Current Status</th></tr>
<tr><td colspan="2">Although it is possible to run fibre through a packer and across the reservoir in wells with sand control / screens, it is not practical to do so in a cased and perforated well. Furthermore, production packer penetrations to enable this create the potential for additional leak paths.

Although subsea systems with fibre to the packer are at ~TRL4 pending further installations by BP and others, and transmission length is currently limited to ~100km, the pace of development is such that it is reasonable to assert that a subsea DAS system will be available and qualified in time for NZT well construction.</td></tr>
<tr><th>Qualification / TRL Milestones</th><th>Dates</th></tr>
<tr><td>BP will be installing subsea DAS systems (fibre terminates above the production packer) in two GoM wells in 2021, and the technology is advancing rapidly due to interest from BP and other operators worldwide.

No NZT-specific qualification planned at present – watching brief.</td><td>n/a</td></tr>
<tr><th>Key Risks</th><th>Mitigations</th></tr>
<tr><td>n/a</td><td>n/a</td></tr>
<tr><th colspan="2">Contingency Plan</th></tr>
<tr><td colspan="2">n/a</td></tr>
<tr><th colspan="2">Key Documents</th></tr>
<tr><td colspan="2">n/a</td></tr>
</table>

A. 16 Borehole Gravimetry (in-well gravimetry logging) Technology 2-pager

Subsurface	Borehole gravimetry (in-well gravimetry logging)	
Date:		
Current TRL: 3/4		
Reference Case:		

Enhancing	
SPA	
Independent Verification SME	
Qualifying Party	
TBC	
Qualification Cost Estimate	
TBC	

Technology Description

Gravity is a well-established technique in mineral prospecting and could be used to detect changes in the subsurface volume/density. For instance, CO_2 replacing denser brine can be detected by monitoring microgravity around the well bore over time (time-lapse gravimetry).

Value Proposition

Need for near-well bore CO_2 plume monitoring to ensure injection conformance and storage monitoring. High-resolution in-well gravimetry could complement 4D seismic acquisition, especially if DAS-VSP technology may not mature sufficiently for deployment in Phase 1.

Example of under-development 3-axes wireline borehole gravity technology (Silicon Microgravity Ltd presented at the 2019 SPE MEOS conference in Bahrain)

Relevant BP / Industry Experience

Silicon Microgravity Ltd has been developing high-resolution 3-axis borehole microgravity tool and is trialing the prototype tool across various projects, including a baseline trial test carried out in Aquistore in early 2020. An additional repeat logging run is planned by Silicon Microgravity possibly in late 2021 or early 2022 when travel restrictions are eased (Covid-19 pandemic)

bp Technology Alignment

<table>
<tr><td colspan="3">Technology could be deployed in injection wells as part of wireline surveillance in dry or wet trees. It could also be the only realistic alternative to time-lapse seismic (if the wind farm footprint makes it prohibitive or unrealistic to carry out).</td></tr>
<tr><th colspan="3">Current Status</th></tr>
<tr><td colspan="3">Technology developed by Silicon Microgravity Ltd with testing on-going at various locations e.g. baseline test in Aquistore (Saskatchewan, Western Canada) in early 2020 with repeat trail scheduled at a later time (possibly late 2021-early 2022).</td></tr>
<tr><th colspan="2">Qualification / TRL Milestones</th><th>Dates</th></tr>
<tr><td colspan="2">Watching brief on industry testing with further qualification for NZT developed as required</td><td>Q4 2021</td></tr>
<tr><th>Key Risks</th><th colspan="2">Mitigations</th></tr>
<tr><td></td><td colspan="2"></td></tr>
<tr><th colspan="3">Contingency Plan</th></tr>
<tr><td colspan="3"></td></tr>
<tr><th colspan="3">Key Documents</th></tr>
<tr><td colspan="3">SPE194845 – Three-axis Borehole Gravity Logging for Reservoir Surveillance – Lofts et al, 2019.</td></tr>
</table>

A.17 Optimised 2DHR Seismic for 4D Monitoring Technology 2-pager

Subsurface	Using 2DHR seismic acquisition for 4D monitoring
Date: 21/10/20	
Current TRL: 5-6	
Reference Case:	

Enhancing	
SPA	
Independent Verification SME	
Qualifying Party	
Supplier Led	
Qualification Cost Estimate	
TBC	

Technology Description

Trialling different seismic acquisition methods using standard 2DHR equipment and testing different processing algorithms to understand if 2DHR can be used for 4D monitoring of CO_2 in the Bunter sandstone at Endurance.

Value Proposition

4D seismic is used for monitoring fields both in production and injection globally. Typically this is with 3D towed-streamer seismic. The overlap on the seabed of the Hornsea 4 windfarm with Endurance means that 3D towed streamer seismic is not possible after 2025 (windfarm installation). Ocean-bottom nodes (OBN) are a mitigation but very expensive. 2DHR is attractive because the shorter streamers are possible tow between the wind turbines and the method is comparatively low cost. However good imaging of the reservoir (deeper than typical HR targets) and repeatability is not proven. Proof of imaging quality and repeatability is needed before we can be certain to use this technique.

Relevant BP / Industry Experience	
2DHR is regularly acquired in BP for all offshore projects to look for shallow hazards. We also have significant experience in seismic acquisition and processing which we are utilising to prove this concept.	
bp Technology Alignment	
Low cost ‘checking’ of CO_2 plume migration would be beneficial for this project due to windfarm constraints but if proven could mitigate the need for more frequent and expensive 3D surveys in the future.	
Current Status	
Data will be acquired in summer 2020 during the survey campaign to test the concept.	
Qualification / TRL Milestones	Dates
Summer offshore survey	Q3 2020
Key Risks	Mitigations
n/a	
Contingency Plan	
n/a	
Key Documents	

A.18 AUVs and Landers: Long Term/Permanent Water Composition and CO2 Content, CO2 Leaks Monitoring

Facilities, Wells, Subsurface	Permanent Landers for Seabed monitoring	bp
Date: 23/10/20		
Current TRL: 6		
Reference Case:		

Enhancing	
SPA	
Independent Verification SME	
Qualifying Party	
Supplier led (e.g. Sonardyne)	
Qualification Cost Estimate	

Technology Description
Monitoring at seabed for CO2 leakage and changes in baseline water quality properties is a vital part of monitoring program for CCUS. Currently there are limited lander and AUV technologies capable of monitoring CO2 and a wider range of water quality parameters that can be deployed as part of site-specific long-term monitoring activity. NZT Specific Requirements: • To develop reliable equipment towards CO2 detection and changes of water quality to be tested around the seabed and along the 60 meter of water column to be able to be permanent. • To provide high accuracy, high precision data to monitor baseline water quality in the water column and identify changes associated with CO2 leakage or release of hypersaline brine. • To remain in position for up to one year without intervention and transmit real time data.
Value Proposition

Need for affordable and reliable landers and AUVs that can be deployed at the Endurance store and surrounding area for long durations without intervention (i.e. min 1 year). Few analogues are tested for CO2 application during ETI, Stem-CCS projects but need to be tuned and tested for Endurance.	
Relevant BP / Industry Experience	
Currently National Oceanographical Centre https://www.noc.ac.uk/projects/oceanids lead the project under ETI funding to adjust developed Landers. Lander technology were advanced for oil and gas application around the platforms and for environmental monitoring at the location around the world. No relevant BP experience.	
Upstream Technology / Internal Alignment	
No relevant BP projects	
Current Status	
Few landers were tested as part of CO2 R&D project (TRL 6) and available on the market (i.e. Sonardyne) however not tested by major companies and qualified for CO2 and brine seepage monitoring. Require more collaboration and screening and further development according of our requirements. One of the major service companies claims need from 6 month to 1 year development to tune it towards Endurance MMV	
Qualification / TRL Milestones	**Dates**
Market engagement (Sonardyne)	Q2 2022
Key Risks	**Mitigations**
• CO2 and water composition sensors not validated • Transmission of data unreliable • Service methods unknown	n/a
Contingency Plan	
AUVs at increased frequency	
Key Documents	

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