Department for
Business, Energy
& Industrial Strategy

Preliminary Wells Field Basis of Design Summary

Key Knowledge Document

NS051-SS-REP-000-00019

August 2021

Acknowledgements

This document describes the well design at the time of writing as a "snapshot in time". It is incomplete and subject to revision and is not intended for design purposes.

Some of the work in this report draws from the wells basis of design for the White Rose project, which aimed to capture CO2 from the Drax power station in Yorkshire and which also used Endurance as the project's primary store (1). The project was cancelled in 2016.

(1) K38 Subsurface Well Report, White Rose Project, January 2016

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Contents

1.0 Executive Summary

Six subsea wells will be drilled as part of the NZT/NEP phase 1 development. A jack-up rig will be used as the relatively shallow water depth (~60m) is unsuitable for a semi-submersible.

The six wells comprise five CO2 injectors (four plus one spare) and an observation well at the crest to monitor plume migration via pressure measurements and production logging. Optimisation as the project progresses may allow the observation well functionality to be incorporated into one of the four injection wells, or the observation well to be used for future CO2 injection – this work will be tied into the subsea layout and architecture work.

In common with many Southern North Sea (SNS) wells targeting the Bunter Sandstone, the well design will incorporate three casing strings and a perforated liner across the reservoir section.

Drilling will start in 2025 with all wells drilled before first CO2 injection commences. Individual well construction duration is ~61 days (average performance target).

Target CO2 injection rate is 1 million tonnes per annum (MTPA ~52MMSCF/D at STP, equivalent to 19,000 bbl water per day approximately) per well average, with up to 1.5 MTPA peak. The wells are designed to be able to be opened up and shut-in for dispatchability, but it is expected that a constant base-load injection rate will be maintained for the first few years of operation, which will allow brine to be swept away from the well bore and reduce the requirement for fresh water-washing for halite dissolution.

The key wells focus areas for the project are:

- Reviewing legacy well integrity – understanding the risk of leakage in exploration and appraisal wells drilled on structure and in the surrounding area over the last 40 years. This work is the subject of a separate document and is not covered here.
- Understanding additional design requirements and equipment qualification to cope with sub-zero temperatures that may occur with a loss of containment in an abnormal situation – for example a large leak caused by damage to a christmas tree could cause CO2 to boil off, leading to very low metal temperatures in the upper part of the well down to the subsurface safety valve (SSSV).
- Cement design to minimise potential leak paths and to facilitate permanent abandonment after cessation of injection.
- Cement design for dispatchability – i.e. the ability to switch wells on and off as demand for electricity and hence CO2 volumes vary.
- Well control – applicable for interventions or infill drilling when the reservoir charged with CO2.

2.0 Project Overview

The concept is to drill subsea wells, in a “distributed” subsea layout i.e. vertical or near vertical wells drilled from standalone locations and tied back to one or more central injection manifolds. Initial work focused on a more conventional “clustered” arrangement with deviated wells drilled from a common drill centre location, and as such much of this work is presented here, but will be amended for the vertical wells before FEED entry. Generally, deviated wells represent the worst case for many aspects of the well design. This will be explained in the various sections of the document.

The wells will be drilled using a jack-up rig. The CO2 will be injected into the Bunter Sandstone reservoir through perforations in the lower (deeper) half of the reservoir thickness in order to maximise the residual trapping of CO2. The CO2 plume will develop and migrate, initially vertically towards the top of the reservoir, and then laterally towards the crest of the structure.

The Storage Complex comprises the Storage Site, its Triassic underburden down to the base of the Zechstein Halite and the overburden up to the top Jurassic Lias. Conformance of the observed and predicted response of the Storage Site to CO2 injection will be monitored during the injection period under a comprehensive Measurement, Monitoring and Verification Plan (MMV Plan). If the operation of the Storage Site behaves as forecast and the dynamic capacity is confirmed, consideration may be given to increasing the quantity of CO2 to be stored in the Endurance Structure. After injection ceases, the Storage Site and Storage Complex will be monitored for a number of years after the wells will be decommissioned before responsibility for the Storage Complex will be transferred to the designated Competent Authority.

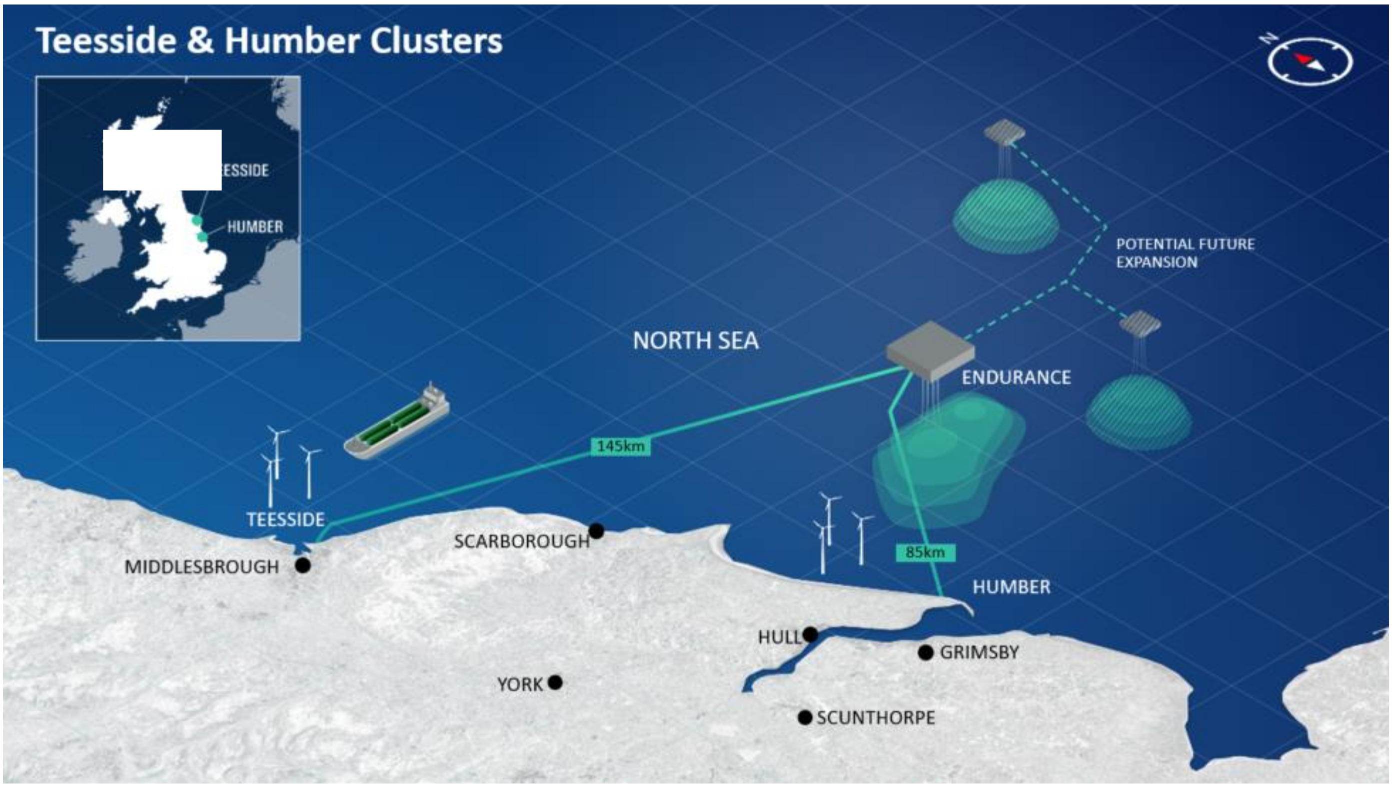


Figure 1 NZT / NEP Phase 1 and Connection to ZCH

3.0 Subsurface

Summary

The Endurance structure is a four-way dip-closure within the Bunter Sandstone Formation in the Southern North Sea (SNS). It is a saline aquifer formation, approximately 22km long, 7km wide and over 200m thick. The crest of the reservoir is located at a depth of approximately 1020m TVD below the sea bed.

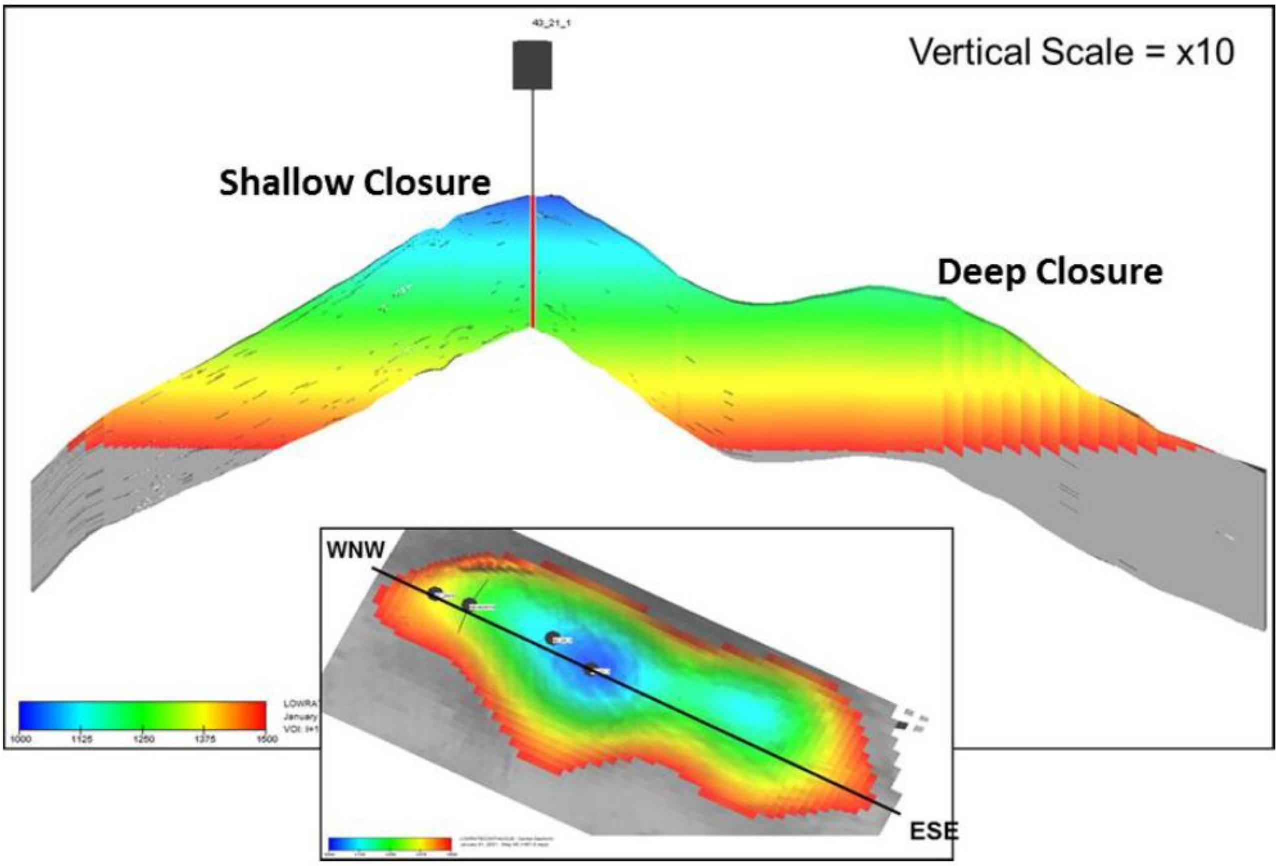


Figure 2 Endurance Structure Cross Section and Plan1 (© National Grid Carbon Limited 2021 all rights reserved)

The Endurance structure is one of several structural closures of the Bunter Sandstone Formation found within the Triassic SNS basin. It has been penetrated by three wells (exploration and appraisal) drilled between 1970 and 2013. Several other exploration and appraisal wells have been drilled surrounding the structure. **Figure 3** shows the top Bunter depth structure map over the Endurance storage site showing license block boundaries (broken black lines) as well as exploration and appraisal wells within the Area of Interest (AOI). Note that wells 42/25d-3, 42/25-1 and 43/21-1 are the only ones to have penetrated the Endurance structure.

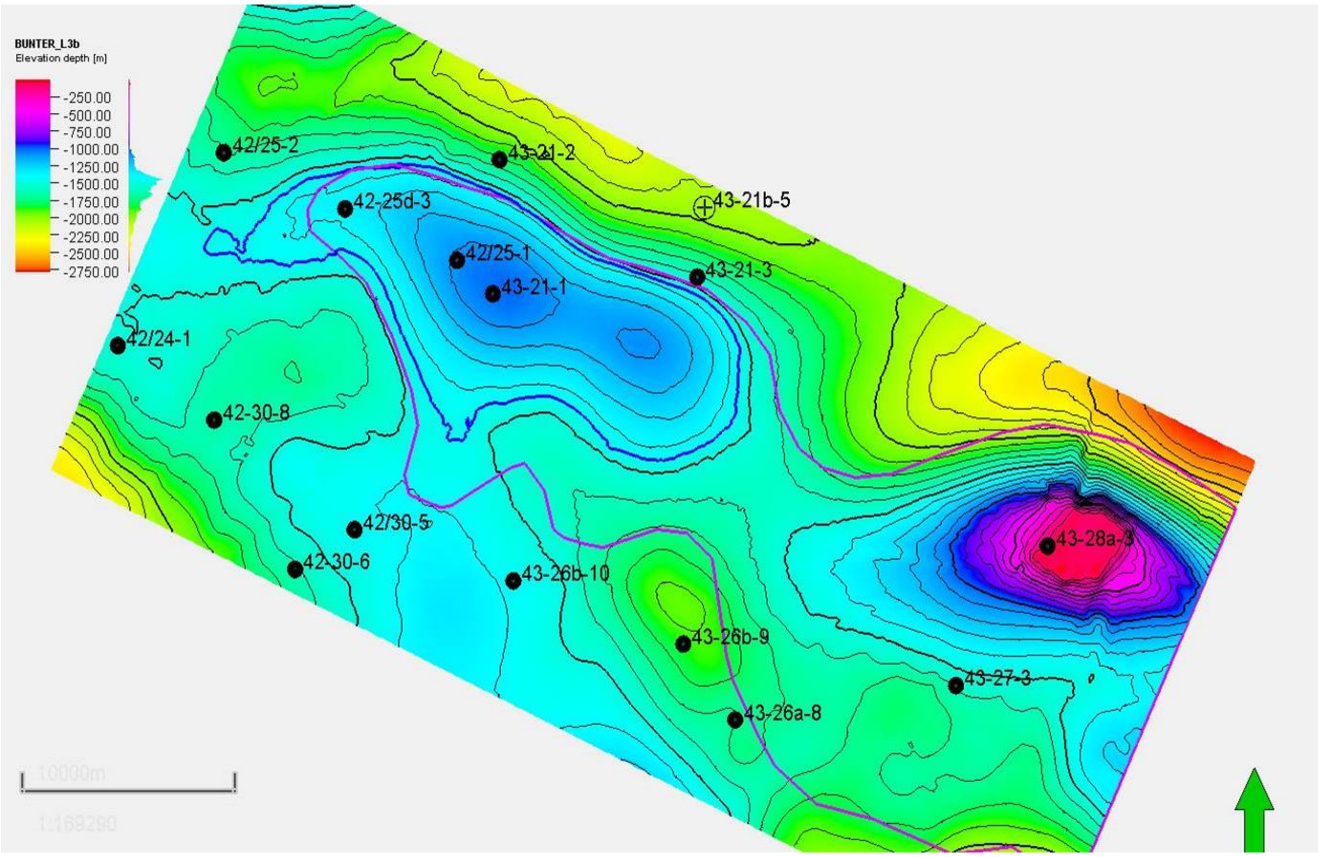


Figure 3 Endurance Contour Map

3.1 Lithology and Formation Tops

3.1.1 Formation Tops

Formation Tops	CI1	CI2	CI3	CI4	CI5	OE1	OW1
	TVDSS (m)	TVDSS (m)	TVDSS (m)				
Seabed	55	58	56	55	58	53	57
Lias	76	66	62	69	73	53	66
Rhaetic Winterton	600	563	531	543	577	506	440
Haisborough - Triton	644	597	575	588	619	532	485
Keuper Anhydrite Member	660	616	599	610	632	551	503
Base Keuper Anhydrite Member	699	665	648	654	675	599	542
Dudgeon	746	721	712	710	721	647	594
Dowsing	847	828	824	823	825	740	692
Muschelkalk Halite Member	895	876	872	875	876	791	736
Base Muschelkalk Halite Member	951	946	931	933	944	851	787
Rot Halite Member	1081	1073	1069	1076	1073	973	912
Rot Clay Member	1188	1187	1183	1194	1190	1076	1016
Bunter Sandstone	1200	1198	1196	1207	1202	1087	1028
Bunter Shale	1457	1423	1441	1452	1478	1351	1277
Well TD	1657	1623	1641	1652	1678	1551	1477

Table 1 Formation Tops (Alternative East and West Observation Well Locations Shown)

3.1.2 Shallow Gas

A site survey will be conducted in 2022; therefore there is no Shallow Hazard Assessment available at this stage.. As there are many offset wells and the area is known to have a very low SHA risk, the project has accepted that this be deferred into FEED / Define.

3.1.3 Shallow Formations

Resistance to drilling was experienced in the 42/24-1 well in the top-hole section. This was possibly due to the presence of glacial pebbles or boulder beds. The conductor subsequently had to be washed to bottom.

Similar issues were also encountered in the 42/25d-3 well, where resistance to drilling was encountered at 170m MDBRT. The conductor subsequently became stuck and had to be recovered to surface and re-run.

3.1.4 Limestone in Lias

Within the Lias, limestone stringers have been encountered resulting in a reduction in ROP. There is also the potential for seepage mud losses into the fractured limestone within the Lias itself.

3.1.5 Reactive Claystones

Offset wells have experienced considerable bit balling due to the reactive clays in both the Lias and the Haisborough group. On two occasions at the start of the 26in section in the 43/21a-4 well, problems were experienced with gumbo whilst drilling with seawater. In the 42/24-1 well the 20in casing string would not pass 235m and had to be recovered to surface to perform a wiper trip. On the second attempt to run the 20in casing, tight spots were encountered from 235m to 374m with up to 210klb overpulls to free the string. Tight spots were also encountered on the 42/25d-3 well while pulling out of hole with the BHA.

3.1.6 Mobile Salts

The salts in the Haisborough group can be mobile. Stuck pipe whilst drilling is be more of a concern than casing collapse due to corrosion. A few of the offset wells have experienced tight spots during wiper trips with up to 140klbs overpulls to free the string.

3.1.7 Dolomite/Anhydrite Stringers

Stringers have been encountered in the offset wells resulting in ledges and tight tripping along with a reduction in ROP.

3.1.8 Losses in Bunter Sandstone

The 42/25-2 and 43/21-2 wells both experienced small mud losses in the Bunter sandstone

3.1.9 Differential Sticking in Bunter Sandstone

The Bunter sand could have a permeability of up to 500mD with an expected pore pressure of 1.11sg. As a result, there is the possibility of differential sticking within the sandstone as seen in the 42/25-2 well where 210klb overpull was required to free the string. The mud weight was reduced from 1.35sg to 1.32sg to mitigate this; however, on the 42/25-1 well the Bunter sand was drilled with 1.41sg with no indications of differential sticking (RFT 1.09 SG EMW pore pressure).

MDT (Modular Dynamics Tester) data acquired in the Bunter sandstone on the 42/25d-3 well recorded a pore pressure of 1.10 SG EMW.

3.2 PPFG and WBS Design Envelopes

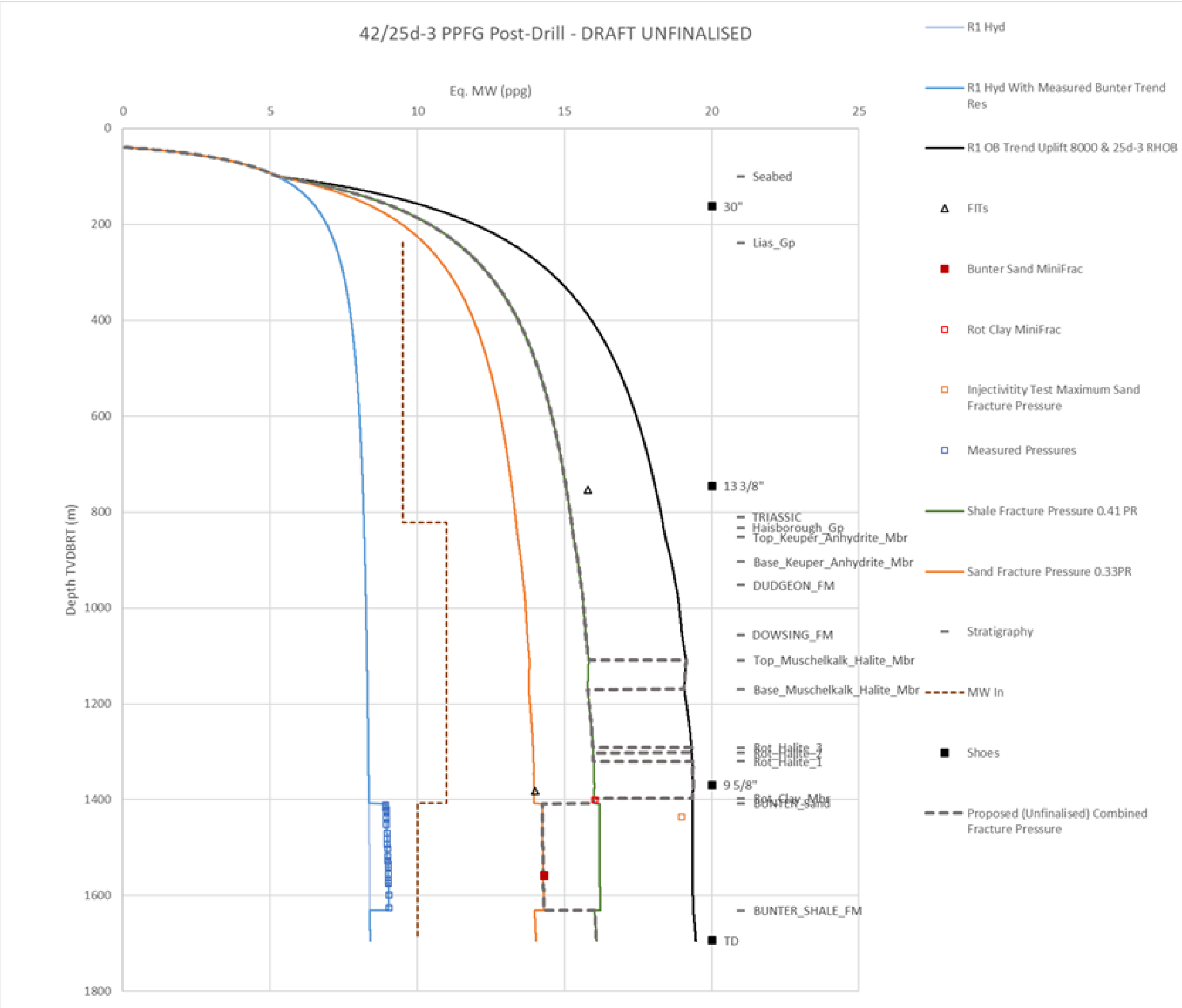


Figure 4 Most Likely PPFG Plot at National Grid 42/25d-3 Well Location

3.3 Temperature Envelope

The bottom hole temperature at datum is estimated to be 57.2 deg C. This equates to a temperature gradient of ~1.1 deg C per 30m with a seabed temperature of ~4 deg C

4.0 Reservoir Data

4.1 Reservoir Conditions

Parameter	Units	
Reservoir Rock		Sandstone
Reservoir Type		Fluvial-Aeolian Clastics
Reservoir Reference (Datum) Depth	mTVDss	1300
Reservoir Top Depth	mTVDss	1010 (Model) 1020 (43/21-1 near crestal well)
Reservoir Spill Point Depth	mTVDss	1400 – 1450 - 1480
Initial Reservoir Pressure at Reference Depth	psia	2030
Shut in Wellhead Pressure	psia	970-1350 (early life 67 bara, late life 93 bara)
Spill Point	mTVDss	1450
Minimum Reservoir Pressure at Reference Depth	psia	2030 at 1300 m TVDss
Temperature at Reference Depth	°C	57
Temperature Gradient	°C / m	Approx. 0.031

Table 3 Reference Data

Formation Properties	Units		Comments
Permeability (P10-P50-P90)	mD	100 – 300 - 500	Expected range for any given well.
Permeability Directionality		Horizontal	
Kv / Kh	Fraction	Macroscale: 0.04 (derived from DST in 42/25d-3), core scale ranging from 0.01 (heterolithics or cemented sand facies) to 10% (clean sand facies)	
Porosity (P10-P50-P90)	Fraction	0.164 - 0.225 - 0.241	Expected range for any given well.
Pore Volume Compressibility	1 / psi	4*10^-6	
Thermal Expansion	1E-5/oC	4.0 (Halite – 3.85@20-40oC, 4.24@40-60oC) / 1.4 (Shale) / 1.2 (Sand)	
Formation Dip & Azimuth	degrees	Near Crest: Dip ~4.25 degrees Azimuth ~300 degrees Down-Flank: Dip 1-2 degrees Azimuth 270 degrees	

Table 2 Formation Properties

Injected Fluid Parameter	Value Pure CO2 (100%) / High N2 (Fig. 16)	Comments
Density at bottom hole (flowing)	960 / 922 kg/m3	BHT = 5 deg C & BHP = 160 bars (cold, liquid)
Density at initial Reservoir conditions	607 / 550 kg/m3	@ T reservoir = 56 deg C and P = 140 bars (hot, supercritical)
Density at late Reservoir conditions	748 / 708 kg/m3	@ T reservoir = 56 deg C and P = 200 bars
Viscosity at bottom hole (flowing)	0.1086 / 0.089 cp	BHT = 5 deg C & BHP = 160 bars (cold, liquid)
Viscosity at initial Reservoir conditions	0.046 / 0.043 cp	@ T reservoir = 56 deg C and P = 140 bars
Viscosity at late Reservoir conditions	0.063/0.058 cp	@ T reservoir = 56 deg C and P = 200 bars

Table 3 CO2 Reservoir Properties

Reservoir Model Parameter	Value	Comments
Wellhead Injection Pressure	110 bara	
Wellhead Injection Temperature	4 to15 deg C	
Shut-in Wellhead Pressure	67-93 bara	Early – late life
Abnormal Situation Temperature	-55 deg C	LOPC or rapid bleed off above SSSV. In theory -78.5 deg C is the lower limit for a dry tree
Completion Skin	5	Assumed
Tubing Size	5 ½"	
Sandface Completion	Cased and perforated	No sand control needed, some flexibility in add-perfs / shut off required, yearly water washing

Table 4 Reservoir Model Parameters

4.2 CO_2 Composition

Component	Max N2 Mol%	Rich Mol%	Lean Mol%
CO2	96.0000	96.0000	98.0000
Water	0.0000	0.0039	0.0020
CO	0.0000	0.1562	0.0781
H2S	0.0000	0.0004	0.0002
Nitrogen	2.0000	1.1715	0.5857
Methane	1.0000	0.7810	0.3905
Ethane	0.0000	0.4686	0.2343
Propane	0.0000	0.3163	0.1582
Butane	0.0000	0.1601	0.0801
Pentane	0.0000	0.0822	0.0411
O2	0.0000	0.0008	0.0004
H2	1.0000	0.7810	0.3905
Argon	0.0000	0.0781	0.0390
Total	100.0000	100.0000	100.0000

Table 7 CO2 Composition

4.3 Displaced Brine

Brine may be produced as it is displaced by the injected CO2, depending on reservoir and aquifer response. The tables below summarise the brine analysis carried out by Expro on behalf of National Grid[2].

Sample Name	ADS80379	ADS80381	ADS80382	ADS80553	ADS80573
Depth	5167.5 ft MD	4722.0 ft MD	4634.0 ft MD	Separator	4589.37 ft MD
Anion	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg
Chloride	154146	148780	148164	155600	155405
Fluoride	0.15	0.12	0.10	0.13	0.14
Sulphate	296	359	385	360	364
Bromide	473	460	444	438	470
Nitrate	<4	<4	<4	<4	<4
Iodide	<4	<4	<4	<4	<4
Phosphate	<20	<20	<20	<20	<20
Total Carbonate (as Bicarbonate)	38	37	43	-	39
Immediate Delay after Flash (min)	11	7	8	-	9
Total Carbonate (as Bicarbonate)	51	43	34	19	41
Subsequent Delay after Flash (min)	6526	6465	6430	-	4785
Formate	<2	<2	<2	<2	<2
Acetate	<2	<2	<2	<2	<2
Propionate	<3	<3	<3	<3	<3
Butyrate	<4	<4	<4	<4	<4
iso-Valerate	<4	<4	<4	<4	<4
Cl:Br	326	323	334	355	331

Table 5 Produced Water Anionic Composition

[2] Expro Compositional Analysis of Water Samples from Appraisal Well 42/25d-3, Report No: SRP1307002, 18th October 2013

Sample Name	ADS80379	ADS80381	ADS80382	ADS80553	ADS80573
Depth	5167.5 ft MD	4722.0 ft MD	4634.0 ft MD	Separator	4589.37 ft MD
Cation	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg
Lithium	7.9	8.0	7.6	8.4	8.5
Barium	2	1	1	1	1
Strontium	108	111	103	117	116
Calcium	8858	8610	8037	8985	9129
Magnesium	2543	3014	3192	3138	3103
Sodium	85512	79664	79953	83763	84792
Potassium	1400	1469	1483	1553	1525
Iron	<1	<1	<1	2	1
Copper	3.9	1.7	1.3	1.0	1.7
Zinc	7.8	8.5	7.9	8.9	8.8
Manganese	2.6	1.6	1.5	1.7	1.7
Aluminium	<0.6	<0.6	<0.6	<0.6	<0.6
Ammonium	<10	<10	<10	<10	<10
Lead	1.1	1.3	1.4	1.4	1.5
Chromium	0.3	0.4	0.4	0.7	0.7
Nickel	<0.2	1.8	1.6	<0.2	0.4
Cadmium	0.2	0.2	0.2	0.1	0.2
Cobalt	0.15	0.16	0.16	0.09	0.08
Silver	<0.04	<0.04	<0.04	<0.04	<0.04

Table 6 Produced Water Cationic Composition

Sample Name	ADS80379	ADS80381	ADS80382	ADS80553	ADS80573
Depth	5167.5 ft MD	4722.0 ft MD	4634.0 ft MD	Separator	4589.37 ft MD
Element	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg
Vanadium	0.07	0.07	0.08	0.07	0.06
Arsenic	1.2	1.3	1.5	2.1	2.4
Boron	9	10	9	10	10
Phosphorus	<6	<6	<6	<6	<6
Silicon	3	3	3	4	4
Sulphur	83	102	107	101	100

Table 7 Elements / Natural Species

Sample Name	ADS80379	ADS80381	ADS80382	ADS80553	ADS80573
Depth	5167.5 ft MD	4722.0 ft MD	4634.0 ft MD	Separator	4589.37 ft MD
Cationic Species	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg
Total Barium	2	2	1	2	1
Total Iron	<1	1	<1	3	1

Table 8 Cationic Species

Sample Name	ADS80379	ADS80381	ADS80382	ADS80553	ADS80573
Depth	5167.5 ft MD	4722.0 ft MD	4634.0 ft MD	Separator	4589.37 ft MD
Mercury	µg/kg	µg/kg	µg/kg	µg/kg	µg/kg
Soluble Mercury	0.4	0.2	0.2	0.3	<0.2
Total Mercury	0.3	0.2	0.2	0.3	<0.2

Table 9 Mercury

Sample Name	ADS80379	ADS80381	ADS80382	ADS80553	ADS80573
Depth	5167.5 ft MD	4722.0 ft MD	4634.0 ft MD	Separator	4589.37 ft MD
Parameter	mg/kg	mg/kg	mg/kg	mg/kg	mg/kg
Total Cl- equivalent	154597	149271	148670	156071	155906
Total Na+ equiv.	101403	96204	96174	101021	102133
Total NaCl equiv.	255999	245474	244845	257092	258039
Cation/Anion Bal.	101.15%	99.39%	99.76%	99.82%	101.02%
Cation/Anion Bias	1.15%	-0.61%	-0.24%	-0.18%	1.02%

Table 10 Salinity and Cation / Anion Balance

4.4 H2S

No H2S was detected in the National Grid well and as we are not injecting incompatible waters and also don't have hydrocarbons, none is expected from these mechanisms; however there are some mineral reactions that theoretically can generate H2S in anhydrite stringers, and so there remains some residual uncertainty (though small).

Until further work is done on p0otential mineral reactions and their likelihood, this BoD assumes that no H2S is present.

5.0 Drilling Engineering Design Summaries

5.1 Well Control

An engineering study was commissioned to assess special requirements for drilling or intervening in a CO_2 charged reservoir. It should be noted that Phase 1 of the NZT/NEP development involves drilling wells into the Endurance field prior to any CO_2 injection i.e. before there will be any risk of a well control incident resulting from a CO_2 influx. The information summarized in Section 0 applies to any well work that is carried out after CO_2 injection has commenced e.g. infill drilling, interventions, P&A etc.

Unlike oil and gas blowouts, where fire and explosion are major concerns, in CO_2 blowouts asphyxiation is the major concern (since CO_2 is heavier than air). Depending on the level of potential risk, it may be appropriate to have self-contained breathing apparatus (SCBA) on-site and available during any post CO_2 injection well operations.

CO_2 forms a supercritical fluid over 31 deg C and 1071 psi (73.4 bar). Above these conditions there is no distinction between the liquid and vapour phases and even a small drop in pressure can lead to a significant increase in volume and vice versa. CO_2 is also known to form hydrates at below 10 deg C and pressure above approximately 700 psi (48 bar).

Due to the above characteristics of CO_2 gas, when drilling into a reservoir that already has experienced CO_2 injection or when performing interventions on CO_2 injection wells, the CO_2 in the reservoir can be present in its supercritical phase. If a well control event were to occur and CO_2 circulated up the annulus, the CO_2 influx would be expected to experience a more significant expansion than a methane kick. This study on a CO_2 well control event has been conducted to understand how a CO_2 influx taken while drilling into supercritical CO_2 or during an intervention would behave while being circulated out of the well.

5.1.1 Modelling a CO2 Kick

Based on industry experience of blowouts from CO_2 injection wells, an OLGA model was developed to understand:

- The behaviour as an influx enters the well and interacts with SOBM and a WBM
- How the CO_2 behaves during shut-in
- How a 25bbls CO_2 influx behaves as it is circulated up the annulus and across the choke in a controlled well control situation
- Whether the pressure and temperature behaviour lead to dry ice / hydrates at the surface equipment

Table 11 below summarises the results from the OLGA model and contrasts the differences between the CO_2 influx behaviour in SOBM and WBM. These results are also contrasted with the same model run with a methane influx for reference.

Stage	CO2 kick (SOBM)	CO2 kick (WBM)	Methane kick (SOBM)
Shut In	Influx enters as liquid No Migration	Influx enters as liquid Influx migrates as liquid (20 hours to reach surface)	Influx enters as gas Influx migrates
Circulating influx up well	Influx turns to gas ~435mMD (916 psi, 29 degC) 13 deg C drop Max pres @ 9-5/8" shoe=2523psi (FG = 2911 psi)	Influx turns to gas ~411mMD (1084 psi, 30 degC) 7 deg C drop Max pres @ 9-5/8" shoe=2480psi (FG = 2911 psi)	
Influx passing 3" choke	13 deg C drop No hydrate formation	9 deg C drop No hydrate formation	
Influx at surface	Gas rate: 8 mm scf/d	Gas rate: 4 mm scf/d	Gas rate: 3 mm scf/d

Table 11 OLGA Well Control Simulation Summary

The key differences between the model results from a 25 bbl CO2 kick in SOBM versus WBM are as follows:

- With SOBM, the liquid CO2 influx does not migrate, however it does with the WBM, reaching the surface after approx. 20 hours.
- Surface gas rates were higher with SOBM as the CO2 is not migrating and is therefore less strung-out.

The key differences between the model results from a 25 bbl CO2 kick in SOBM versus a 25 bbl methane kick in SOBM are as follows:

- With methane, since it enters as a gas, the resulting BHP (prior to shut in) is less due to the migration of the methane.
- CO2 kick is more difficult to detect than methane (due to the fact it is coming into the wellbore as a liquid – similar to a methane kick going into solution in SOBM)
- CO2 kick results in a higher gas rate on surface due to the more rapid expansion of CO2, hence the importance of early kick detection systems (e.g. Coriolis flowmeter) on the rig.

5.1.2 Measures to Limit CO2 Well Control Risks

- Enhanced detection, vigilance, training and drills on the CO2 well control risks. Some examples may include high accuracy flow measurements.
- Detailed metallurgy study for all tubulars and elastomeric materials installed to prevent CO2 corrosion of downhole materials. The use of impressed and passive cathodic protection systems for casing strings is documented in some CO2 EOR well designs.
- Cementing design for CO2 storage.
- Use of OBM and CO2 inhibitor in fluids to minimize carbonic acid production in the mud system. Use of corrosion inhibited packer fluids or base oil.
- Nipple profiles above packers in tubing strings to allow pulling tubing without the risk of flow up the tubing requiring installation of stab-in safety valve to stop flow. This is a recommendation in the World Oil article that may have prevented or mitigated well control events from escalating.
- Contingency planning for the response to an aggressive blowout and emergency response training.
- Breathing apparatus to mitigate the asphyxiation risks associated with a CO2 release to atmosphere.

5.1.3 Rig Specification for CO2 Wells

There are no mobile rigs currently “certified” for use in pure CO2 service.

As the potential for CCUS projects in the UK and internationally evolves, there will be a requirement to drill new wells or carry out workovers in fields that are charged with CO2.

Conventional hydrocarbon industry drilling rigs are generally not set up for operations in a pure CO2 environment; the properties of CO2 may mean that existing rig equipment, processes and procedures may need modification or amendment.

The lists below outline some of these aspects that may need consideration, but it is not an exhaustive list. It is recommended that guidance on specification for and operations by rigs in a pure CO2 environment are developed by the wider industry so that all stakeholders can be consulted, as is done for technical guidance on a variety of topics by industry bodies such as OGUK and the North Sea Chapter of the IADC.

Rig Systems

- BOPs – metallurgy and sealing
- Gas detection – set up for CO2 detection
- Choke manifold – metallurgy for corrosion and hydrate suppression

- Rig de-gasser system – potential for increase in piping size as CO_2 gas phase transition is generally at a lower pressure than hydrocarbon gas, so gas velocities may be higher for the same kick volume
- Other rig safety systems
- Temporary refuges
- Lifeboats – launching in a CO_2 environment
- For a CO_2 discharge in the water column – water acidity and life-raft material / survival suit material
- Crew training and escape procedures

Certification and Other

- Rig certification / certifying authority requirements
- Safety case for UK operation

5.2 Kick Tolerance

Kick tolerance calculations have been performed using the kick tolerance calculator in the Global Well Engineers' Toolkit. The key input data and results for each calculation are summarised in sections 0 and 0 below.

5.2.1 12-1/4" Section

Key Assumptions

Trajectory: Well CI-4 (note - deviated well trajectory)

Weak Point: 20" x 13-3/8" shoe @ 458m MD BRT (445mTVD BRT)

Min FG = 1.57 SG (Sand Shmin), Max FG = 1.83 SG (Shale SHmin)

Influx depth: Top bunter sandstone @ 1772m MD BRT (1189mTVD BRT). Note this is based on inadvertently penetrating reservoir

Most Likely PP = 1.10 SG

Mud Weight: 1.33 SG (required for WBS)

Drill string: 1582m 5-1/2" DP, 100m 5-1/2" HWDP, 90m 8-1/2" DC

Gas density: 0.5537 SG

Results

Kick Tolerance assuming minimum FG = 6 bbls

Kick Tolerance assuming max FG = 32 bbls

Conclusion

>25 bbls kick tolerance can be achieved assuming the 20" x 13-3/8" shoe is set in shale and shoe can be assumed to have strength equivalent to the Shmin for shale. It should be noted that these kick tolerance calculations are conservative for the following reasons:

- The 12-1/4" hole section is predominantly shale and halite. There are no expected sand intervals and hence it is unlikely that the section will contain a weak point with strength equivalent to sand Shmin.
- Kick tolerance calculations assume the 12-1/4" section penetrates the Bunter Sandstone formation (and associated higher PP), however it is planned to TD the section in the Rot Clay formation
- Kick tolerance calculations assume worst case of methane kick, however the Bunter sandstone is known to contain brine. Note that if the influx density is changed to 1.18

SG (approx. density of brine in Bunter), the kick tolerance values rise to 33/123 bbls (min/max FG at 13-3/8” shoe).

- Kick tolerance calculations are based on a relatively shallow 20” x 13-3/8” casing setting depth. The setting depth was chosen based on limiting the hole angle in the 17-1/2” section to 30 degrees should this section be drilled using sea water. The switch to vertical wells will allow the 20” x 13-3/8” casing to be set deeper.

An FIT of 1.77 SG at the 13-3/8” shoe would be sufficient to ensure a minimum of 25 bbls kick tolerance is available to drill the 8-1/2” section.

5.2.2 8-1/2” Section

Key Assumptions

Trajectory:	Well CI-4 (note - deviated well trajectory)
Weak Point:	9-5/8” shoe @ 1,759m MD BRT (1,182mTVD BRT)
	Min FG = 1.66 SG (Sand Shmin), Max FG = 1.94 SG (Shale SHmin)
Influx depth:	Well TD @ 2,342m MD BRT (1,489mTVD BRT).
	Most Likely PP = 1.10 SG
Mud Weight:	1.36 SG (required for WBS)
Drill string:	2,156m 5-1/2” DP, 150m 5-1/2” HWDP, 40m 6-3/4” DC
Gas density:	0.5537 SG

Results

Kick Tolerance assuming minimum FG = 123 bbls

Kick Tolerance assuming max FG: Infinite (gas extends above weak point)

Conclusion

>25 bbls kick tolerance can be achieved for assuming either the minimum (Shmin sand = 1.66 SG) or maximum (Shmin shale=1.94 SG) FG 9-5/8” shoe which is planned to be set in the Rot clay formation.

An FIT of 1.52 SG at the 9-5/8” shoe would be sufficient to ensure a minimum of 25 bbls kick tolerance is available to drill the 8-1/2” section.

5.3 Well Placement

The reference case is to drill vertical wells using a distributed subsea layout. This section was written when the reference case was to drill deviated wells from a clustered subsea layout which represents the worst case for well placement considerations. As such, the work on deviated wells has been retained. Vertical well placement design is underway but incomplete at the time of writing, and will be updated as studies are completed.

5.3.1 Well Design Envelope

An offset review of well trajectories in the Southern North Sea was conducted to understand the approximate well step-out which has been achieved. The key points from this offset analysis are as follows:

- Maximum inclination is ~68 deg but typically 55 to 60 deg
- Maximum step-out based on the offset data are as follows:
    - Top Bunter (~1200 mTVD):
        - Max step-out = ~1250m (assuming 60 deg in overburden and reservoir)
    - Well TD (~1500 mTVD):
        - Max step-out = ~1800m (assuming 60 deg in overburden and reservoir). See Figure 5.
- Increasing inclinations past these limits will require further well-bore stability work, and also impacts intervention capability e.g. tractors may be required for slickline and e-line conveyance.

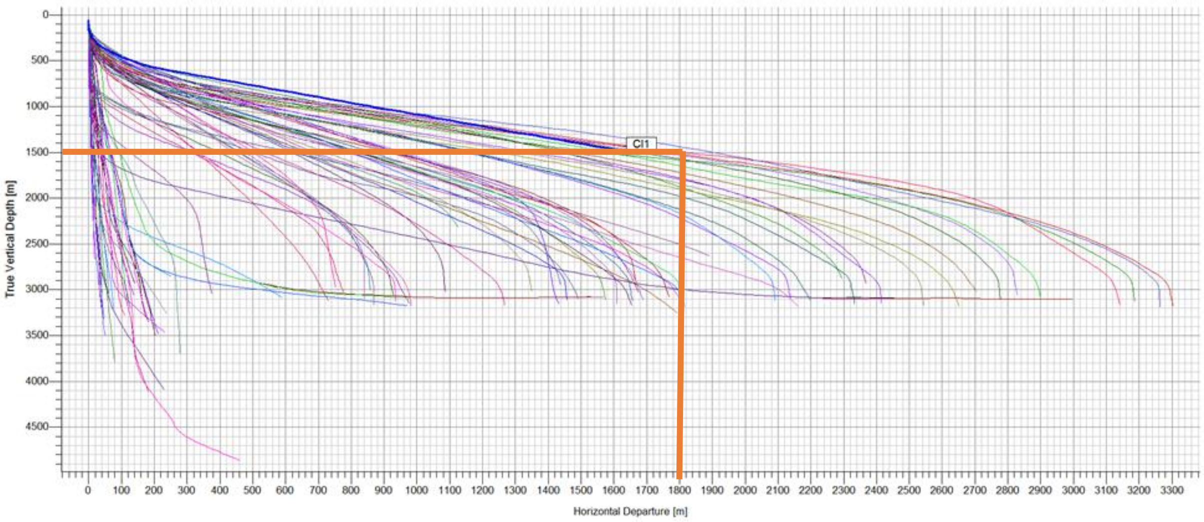


Figure 5 Endurance Offset Well Step-out

5.3.2 Clustered Subsea Layout

Clustered layout bottom hole targets are shown in Table 12 as simple point targets which have been used to identify a drill centre location and provisional well trajectories.

Well	Easting (m)	Northing (m)	Z (mTVD SS)
CI1	367634	6008982	1482
CI2	368579	6008113	1459
CI3	369236	6007671	1459
CI4	370118	6007360	1464
CI5	369874	6010227	1274

Table 12 Clustered Layout Targets (Drill Centre DC1)

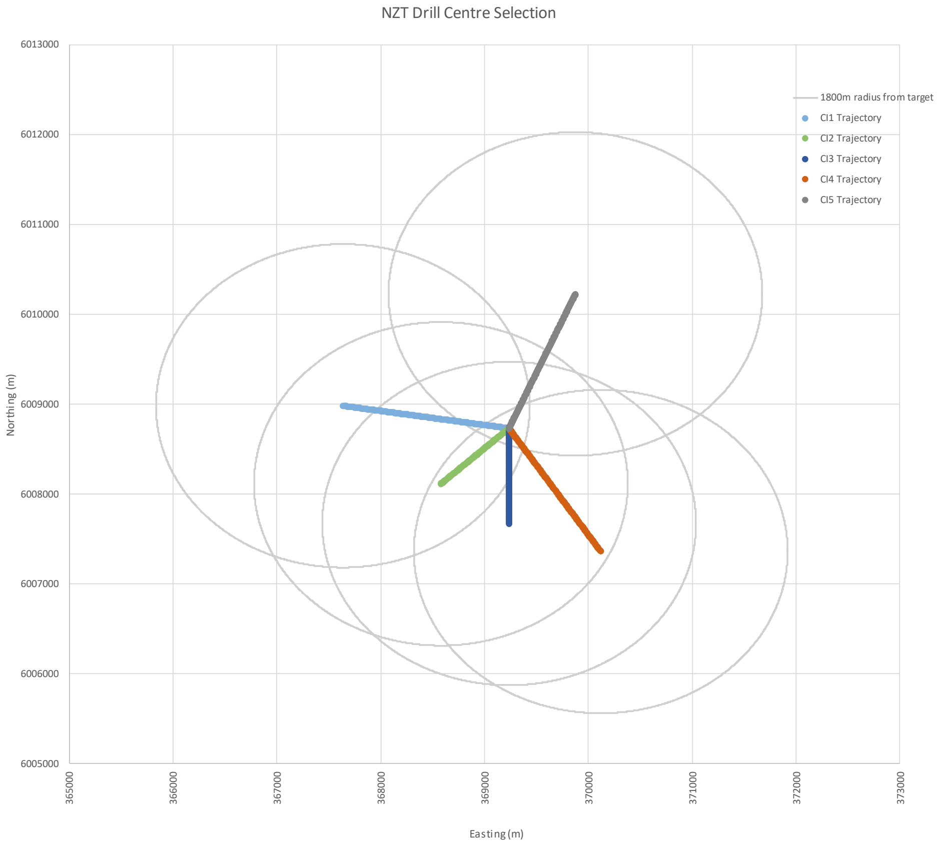


Figure 6 Drill Centre DC1 Selection (Clustered Subsea Layout)

The coordinates of the provisional drill centre location for the clustered subsea layout are provided below:

Geodetic Parameters: ED50, UTM Zone 31N (0E to 6E)				
Location	Easting	Northing	Latitude	Longitude
DC1	369234	6008731	54º 12’31.433” N	0º 59’42.024” E

Table 13 Provisional Drill Centre Location (DC1) for Clustered Subsea Layout

Figure 7 below shows provisional trajectories for the clustered subsea layout from drill centre DC1. These trajectories have been based on the following assumptions:

- Water depth 60m
- Vertical to 75m BML
- Build at 3 deg/30m to align on target
- Hold tangent to targets

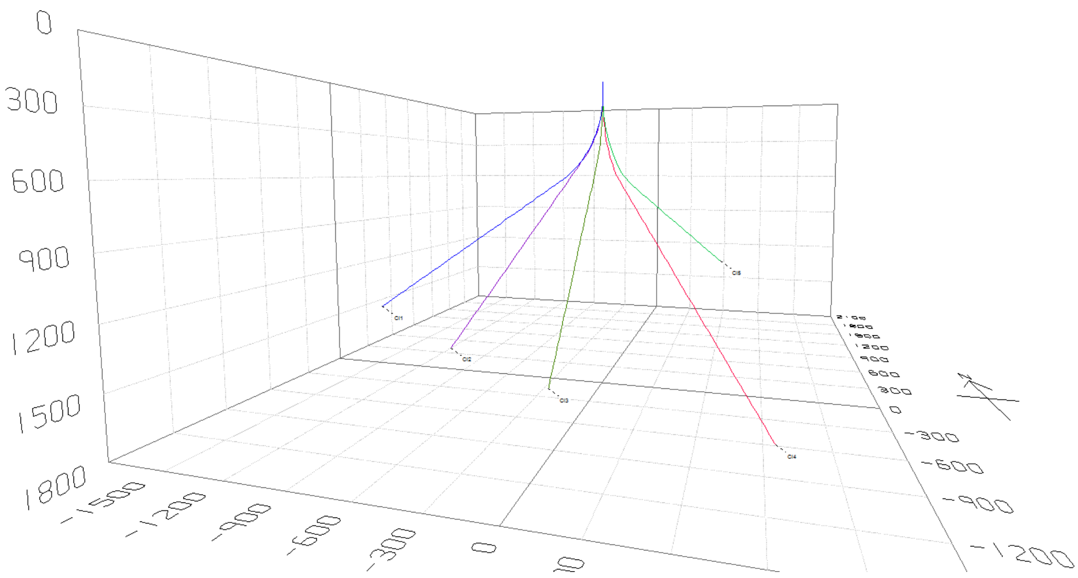


Figure 7 Trajectories (Clustered Subsea Layout from Drill Centre DC1)

The trajectories are summarised in Table 14 below.

Well	mMD	mTVD	Max Inclination (deg)	Well Azimuth (deg)	Max Step-out (m)	Max DLS (deg/30m)
Cl1	2316	1482	57.5	277	1619	3.0
Cl2	1760	1459	38.8	225	901	3.0
Cl3	1866	1459	44.2	178	1060	3.0
Cl4	2317	1464	58.3	146	1632	3.0
Cl5	2222	1274	64.5	22	1627	3.0

Table 14 Provisional Trajectory Summary (Clustered Layout form Drill Centre DC1)

5.3.3 Distributed Subsea Layout

The provisional bottom hole targets in Table 15 are for vertical wells from a distributed layout. They are simple point targets at this stage, but will be refined into polygons with some areal extent in FEED / Define. Note that an additional CO_2 injection well was added to the scope following the agreement to include CO_2 volumes from Humberside which was not included in the original clustered / deviated layout.

Well	Easting (m)	Northing (m)	Z (mTVD SS)	Comment
CI1	368989	6007789	1457	
CI2	366368	6012646	1423	
CI3	371166	6011956	1441	
CI4	373452	6007149	1452	
CI5	374907	6009576	1478	Additional Well added after Humber MOC
OE1	377111	6007326	1351	Observation Well (East Side)

Table 15 Provisional Targets (Base Bunter, Distributed Layout)

Figure 8 below shows provisional (vertical) trajectories for the distributed subsea layout.

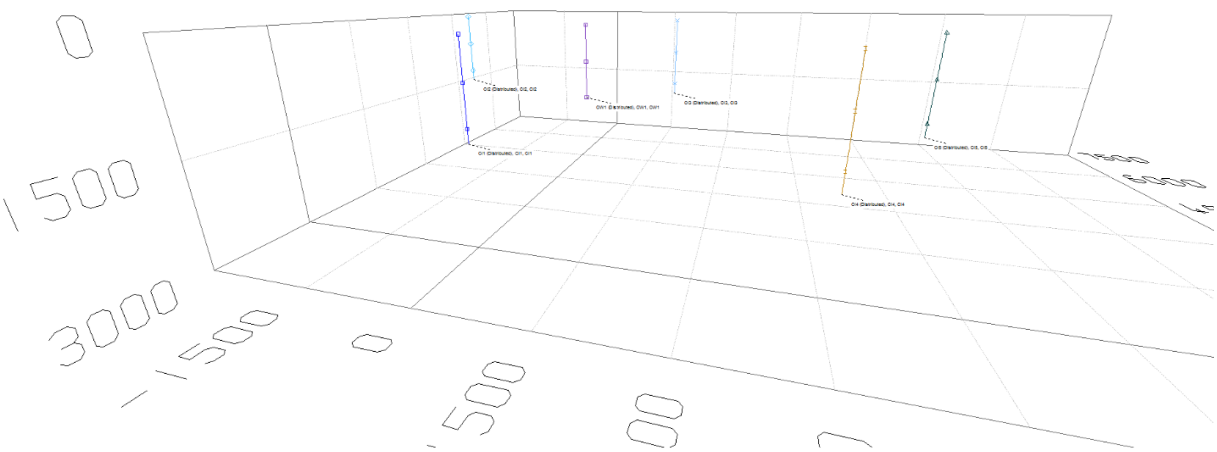


Figure 8 Provisional Trajectories (Distributed Subsea Layout)

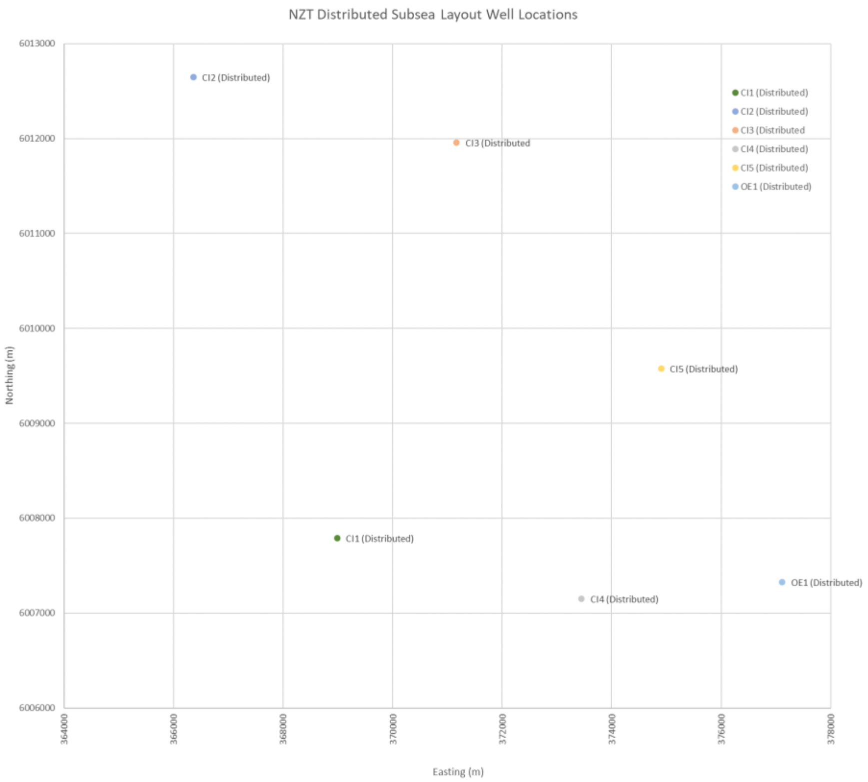


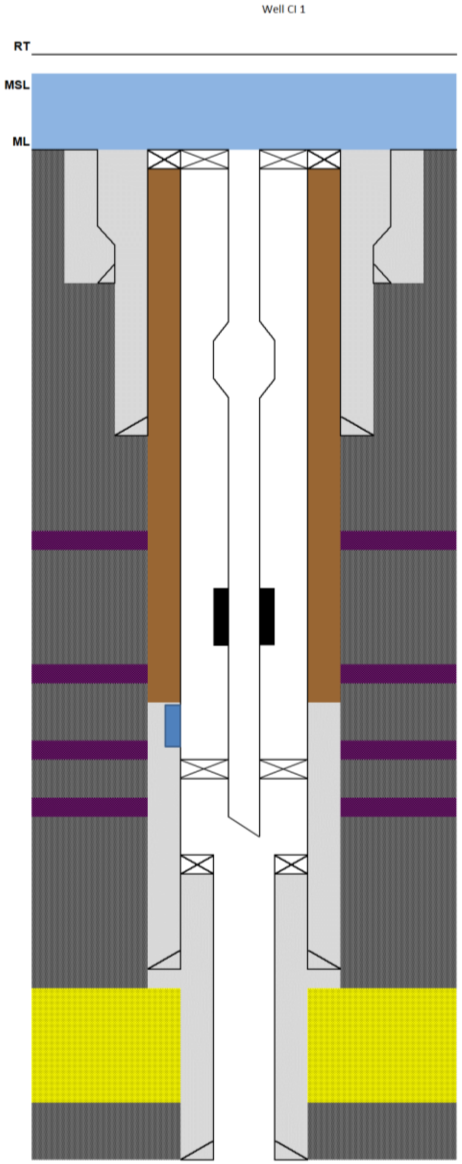
Figure 9 Well Spud Locations (Distributed Subsea Layout)

The coordinates of the provisional spud locations for the distributed subsea layout are provided below:

Geodetic Parameters: ED50, UTM Zone 31N (0E to 6E)					
Well	**Easting**	**Northing**	**Latitude**	**Longitude**	**Comment**
CI1	368989	6007789	54º 12’0.739” N	0º 59’29.989” E	
CI2	366368	6012646	54º 14’35.360” N	0º 56’57.643” E	
CI3	371166	6011956	54º 14’17.462” N	1º 1’23.637” E	
CI4	373452	6007149	54º 11’44.101” N	1º 3’37.083” E	
CI5	374907	6009576	54º 13’3.841” N	1º 4’53.694” E	
OE1	377111	6007326	54º 11’53.025” N	1º 6’58.641” E	Observation Well Option on East (Referer
OW1	369874	6010227	54º 13’20.399” N	1º 0’14.989” E	Observation Well Option on West

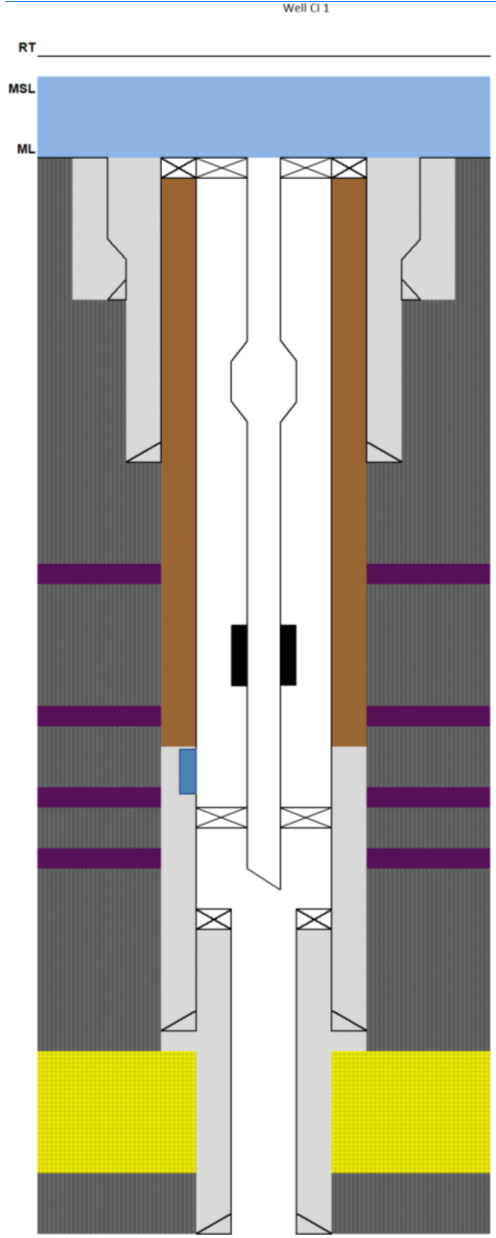
Table 16 Provisional Spud Locations for Distributed Subsea Layout

5.4 Well Schematics



	mMD BRT	mTVD BRT	mMD SS	mTVD SS	Inclination	Azimuth	Comment
RT	0	0	-25	-25	0	0	
MSL	25	25	0	0	0	0	
Seabed/Mud Line	83	83	58	58	0	0	
30" x 20" Conductor TOC	83	83	58	58	0	0	assume cemented back to ML
13-3/8" Casing TOC	83	83	58	58	0	0	assume cemented back to ML
Lias	117	117	92	92	0	0	
30" x 20" Conductor	155	155	130	130	0	0	assume 6 joints of conductor
5 1/2" SSSV	500 to 600 TBC						
13-3/8" Casing	690	619	665	594	53	305	From White Rose BoD (594mTVDSS in Lias formation)
Rhaetic Winterton	692	620	667	595	53	305	
Haisborough - Triton	757	655.9	732	631	59.46	305	
Keuper Anhydrite Member	795	675	770	650	60	305	
Base Keuper Anhydrite Member	889	721.92	864	697	60	305	
Dudgeon	999	777	974	752	60	305	
Dual DHPTG (Tubing and Annulus)							
Dowsing	1209	881.92	1184	857	60	305	
Muschelkalk Halite Member	1307	931	1282	906	60	305	
9-5/8" Casing TOC	1360	957	1335	932	60	305	assume TOC 550m above shoe (leave lower completion in place for PA)
Overburden Pressure Gauge							
Base Muschelkalk Halite Member	1433	993.92	1408	969	60	305	
Rot Halite Member	1685	1120	1660	1095	60	305	
5 1/2" Tubing	1720	1137	1695	1112	60	305	
5 1/2" or 7" Liner TOC	1760	1157.42	1735	1132.42	60	305	assume cemented back to Liner Top
7" Liner (top)	1760	1157.42	1735	1132.42	60	305	assume 150m above 9-5/8" casing
Rot Clay Member	1899	1226.92	1874	1202	60	305	
9-5/8" Casing	1910	1232	1885	1207	60	305	assume 9-5/8" midway through rot clay
Bunter Sandstone	1921	1238	1896	1213	60	305	
Bunter Shale	2469	1511.92	2444	1487	60	305	
5 1/2" or 7" Liner	2543	1548.92	2518	1524	60	305	assume set at TD
TD	2543	1549	2518	1524	60	305	

Figure 10 Wellbore Schematic (Well CI4 drilled from drill centre DC1 – clustered subsea layout)



	mMD BRT	mTVD BRT	mMD SS	mTVD SS	Inclination	Azimuth	Comment
RT	0	0	-25	-25	0	0	
MSL	25	25	0	0	0	0	
Seabed/Mud Line	83	83	58	58	0	0	
30" x 20" Conductor TOC	83	83	58	58	0	0	assume cemented back to ML
13-3/8" Casing TOC	83	83	58	58	0	0	assume cemented back to ML
Lias	117	117	92	92	0	0	
30" x 20" Conductor	155	155	130	130	0	0	assume 6 joints of conductor
5 1/2" SSSV	600	600					
13-3/8" Casing	619	619	665	594	53	305	From White Rose BoD (594mTVDSS in Lias formation)
Rhaetic Winterton	620	620	667	595	53	305	
Haisborough - Triton	656	655.9	732	631	59.46	305	
Keuper Anhydrite Member	675	675	770	650	60	305	
Base Keuper Anhydrite Member	722	721.92	864	697	60	305	
Dudgeon	777	777	974	752	60	305	
Dual DHPTG (Tubing and Annulus)							
Dowsing	882	881.92	1184	857	60	305	
Muschelkalk Halite Member	931	931	1282	906	60	305	
9-5/8" Casing TOC	957	957	1335	932	60	305	assume TOC 550m above shoe (leave lower completion in place for PA)
Overburden Pressure Gauge							
Base Muschelkalk Halite Member	994	993.92	1408	969	60	305	
Rot Halite Member	1120	1120	1660	1095	60	305	
5 1/2" Tubing	1137	1137	1695	1112	60	305	
5 1/2" or 7" Liner TOC	1157	1157.42	1735	1132.42	60	305	assume cemented back to Liner Top
7" Liner (top)	1157	1157.42	1735	1132.42	60	305	assume 150m above 9-5/8" casing
Rot Clay Member	1227	1226.92	1874	1202	60	305	
9-5/8" Casing	1232	1232	1885	1207	60	305	assume 9-5/8" midway through rot clay
Bunter Sandstone	1238	1238	1896	1213	60	305	
Bunter Shale	1512	1511.92	2444	1487	60	305	
5 1/2" or 7" Liner	1549	1548.92	2518	1524	60	305	assume set at TD
TD	1549	1549	2518	1524	60	305	

Figure 11 Wellbore Schematic (Well CI4 drilled vertically – Distributed subsea layout)

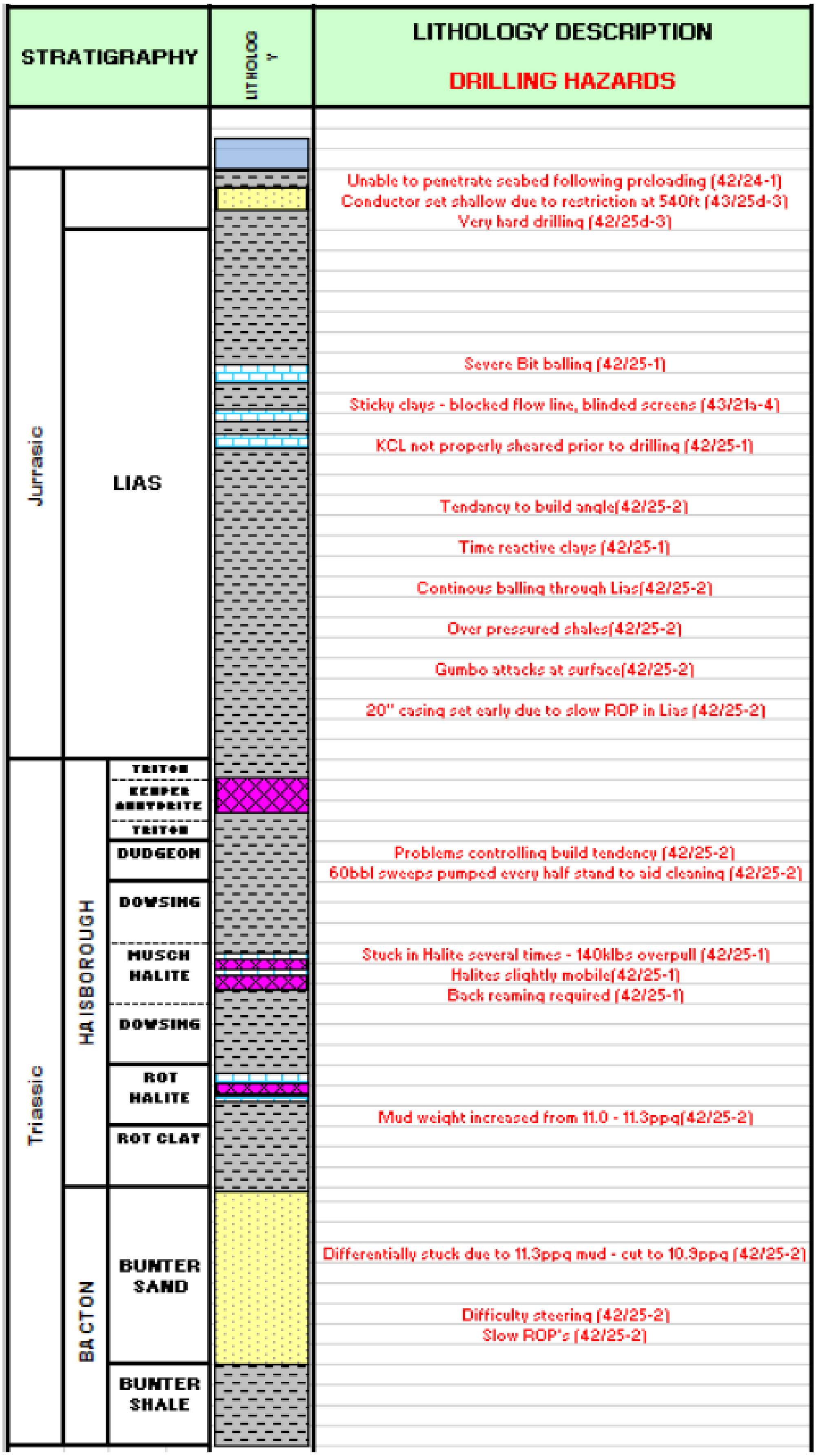


Figure 12 Drilling Hazards

5.5 Torque and Drag, Hydraulics

Torque, drag, and hydraulics and hole cleaning simulations were performed for well trajectory CI4 (clustered subsea layout) in WellPlan for the following operations:

- Drilling 17-1/2" hole, running 20" x 13-3/8" surface casing
- Drilling 12-1/4" hole, running 9-5/8" production casing
- Drilling 8-1/2" hole, running 7" liner (noting 5-1/2" liner more likely)

The key assumptions used to model each hole section are summarised in

Table 17. Rig limitations are based on a typical jack-up capable of operating in 120m water depth that has worked for bp in 2016 on Mungo. Graphs of the key results are show in Figure 13 to Figure 30.

In summary, there are no torque, drag, hydraulics or hole cleaning concerns for this well:

- All expected hook loads and torques are comfortably within rig and drill string limits
- Hole cleaning is achievable at without meaningful restriction on ROP
- SPP is comfortably within rig limitations
- ECD values are comfortably less than SHmin (using MW required for WBS)

	17-1/2" Hole 13-3/8" Casing	12-1/4" Section 9-5/8" Casing	8-1/2" Section 7" Liner
Section TD (m)	458	1,759	2,342
Drill pipe	5-1/2" (21.9 ppf, S135, DTTJ connection, Premium)		
Mud Weight (SG)	1.02 (Sea water)	1.33 (SOBM)	1.36 (SOBM)
Drilling Flowrate (GPM)	1,050	1,050	550
ROP (m/hr)	30	30	30
RPM	120	120	120
Cuttings Size (mm), Density (SG)	5mm, 2.4 SG	4mm, 2.5 SG	2mm, 2.6 SG
Friction Factors (CH/OH)	0.25 / 0.30	0.25 / 0.30	0.25 / 0.30
Max hookload (Klbs)	1,500		
Max Pressure (psi)	7,500 (stand pipe), 6,285 (3 P-220 pumps with pumps with 6" liner)		
Max Torque (kft.lbs)	45.5 (Varco TDS-4)		

Table 17 NZT/NEP Well CI4 Torque, Drag & Hydraulics Key Assumptions

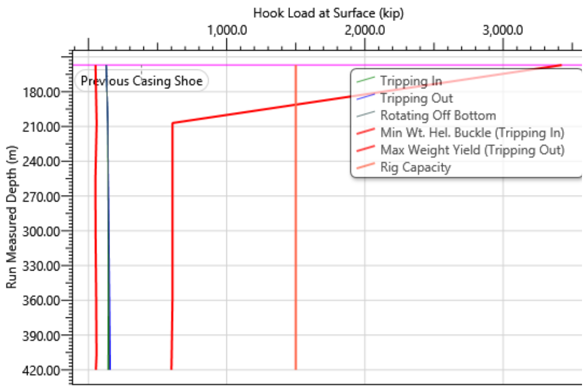


Figure 13 Well CI4 - 17-1/2" Drag Plot

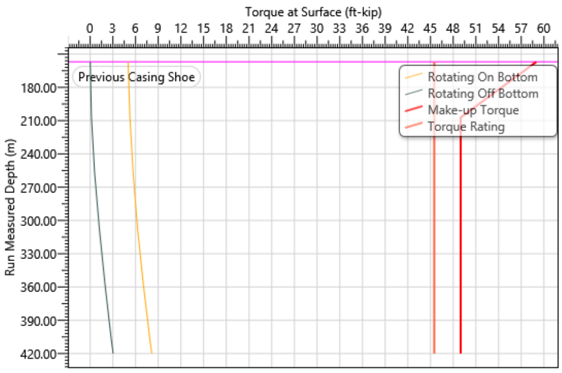


Figure 14 Well CI4 - 17-1/2" Torque Plot

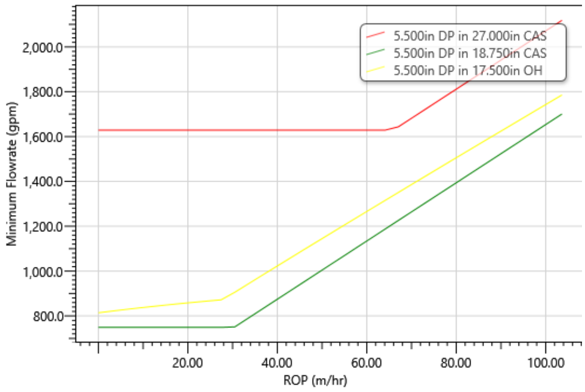


Figure 15 Well CI4 – 17-1/2" Hole Cleaning Plot

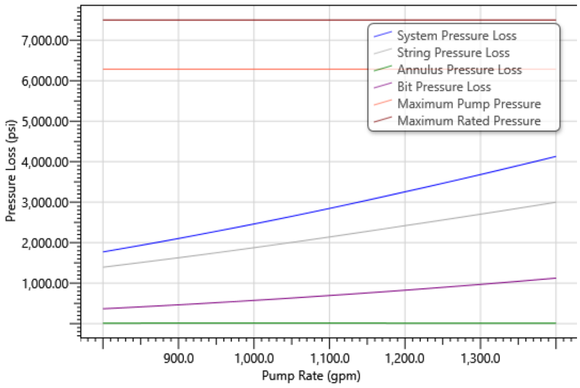


Figure 16 Well CI4 - 17-1/2" SPP Plot

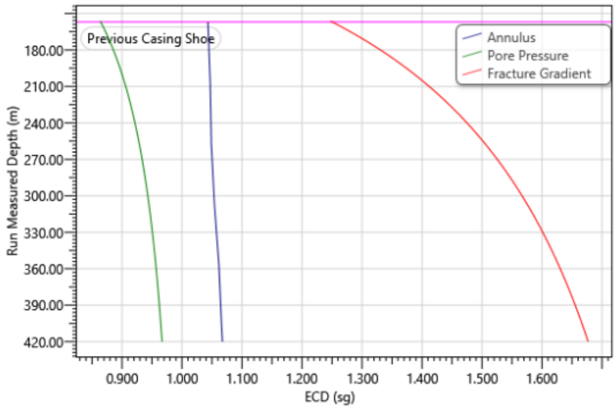


Figure 17 Well CI4 – 17-1/2" ECD Plot

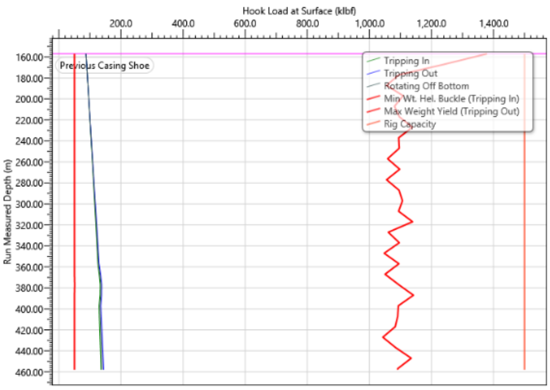


Figure 18 Well CI4 – 20” x 13-3/8” Drag Plot

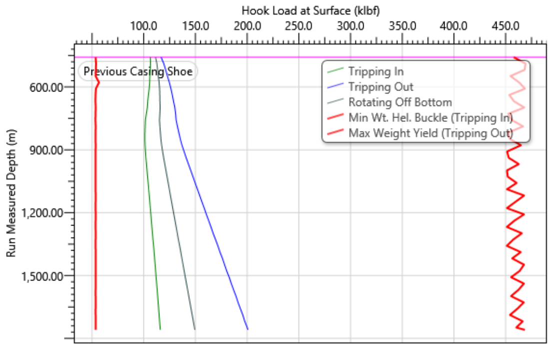


Figure 19 Well CI4 - 12-1/4" Drag Plot

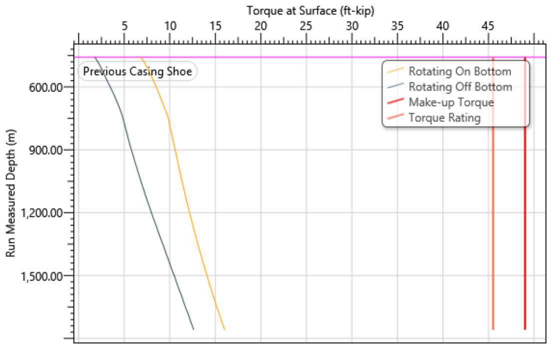


Figure 20 Well CI4 - 12-1/4" Torque Plot

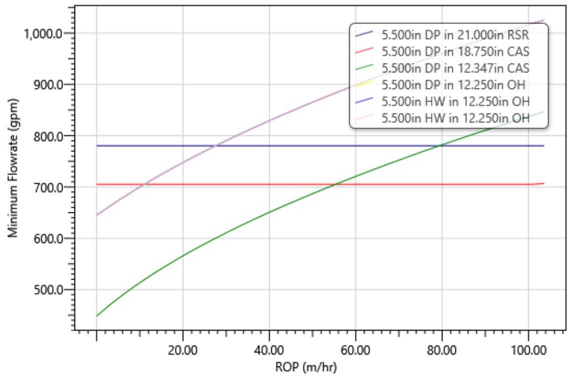


Figure 21 Well CI4 – 12-1/4" Hole Cleaning Plot

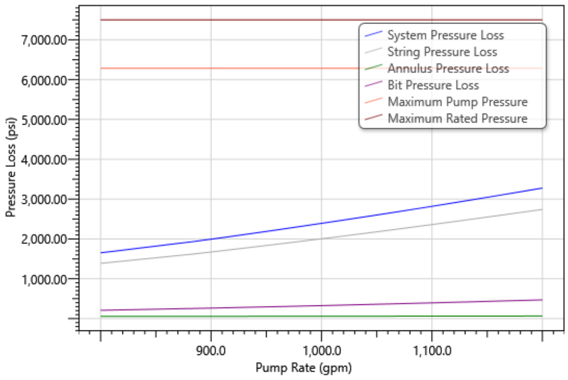


Figure 22 Well CI4 - 12-1/4" SPP Plot

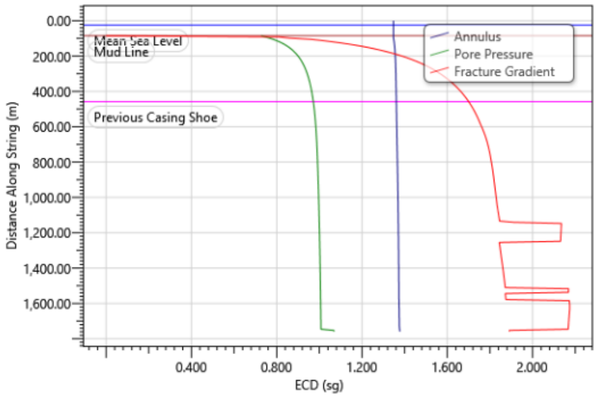


Figure 23 Well CI4 – 12-1/4" ECD Plot

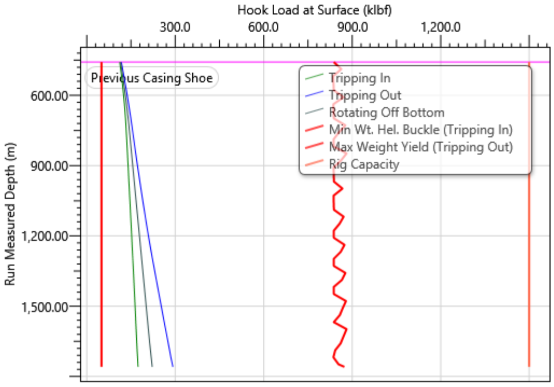


Figure 24 Well CI4 – 9-5/8" Casing Drag Plot

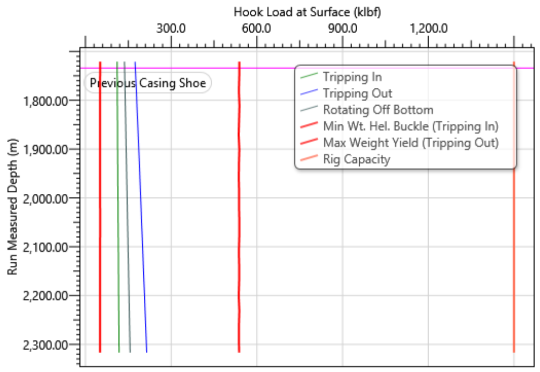


Figure 25 Well CI4 - 8-1/2" Drag Plot

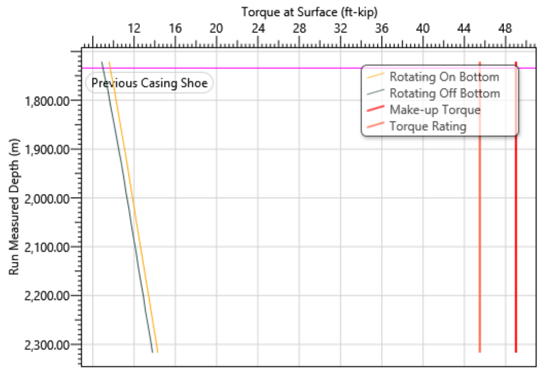


Figure 26 Well CI4 - 8-1/2" Torque Plot

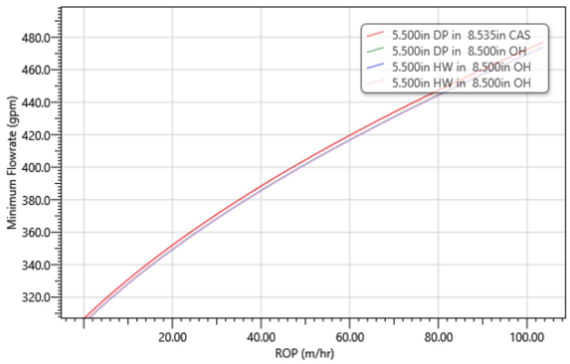


Figure 27 Well CI4 – 8-1/2" Hole Cleaning Plot

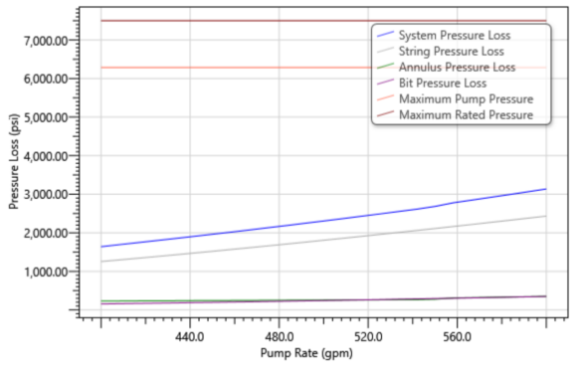


Figure 28 Well CI4 - 8-1/2" SPP Plot

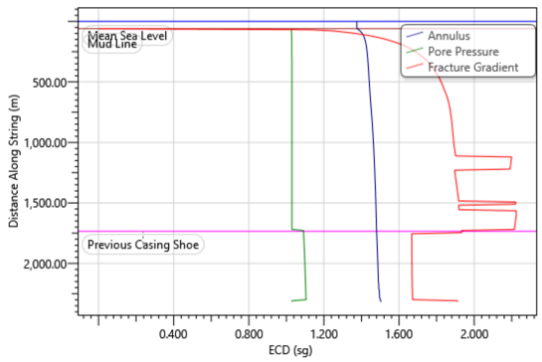


Figure 29 Well CI4 – 8-1/2" ECD Plot

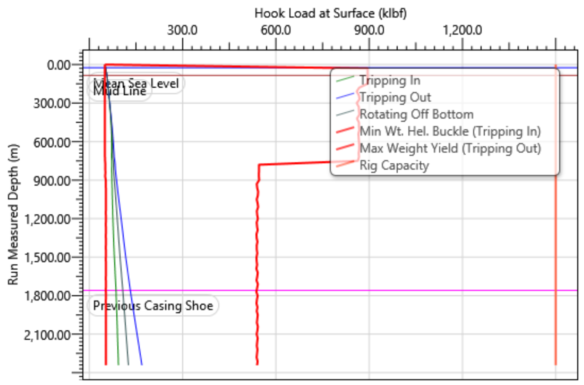


Figure 30 Well CI4 – 7" Liner Drag Plot

5.6 Drill String / Casing Landing String

Torque and drag modelling (Section 0) for the CI4 NZT/NEP deviated well assumes the following:

Drill pipe: 5-1/2” (21.9 ppf, S135, DSTJ connection, Premium)

HWDP: 5-1/2” (55.0 ppf, DSTJ Connection)

An assumption has been made that HWDP will be used to land the casing strings, with the production liner run on drill pipe. The drag modelling assumed friction factors of 0.25 in cased hole and 0.30 in open hole.

Torque and drag modelling indicated no issues related to exceeding the drill pipe or landing string mechanical limitations are expected.

Operation	Max Pick Up Weight (klbs)	Overpull Margin (klbs)[3]
Running Conductor	168	1,136
Drilling 17-1/2” Hole	158	380
Running 20” x 13-3/8” Casing	144	947
Drilling 12-1/4” Hole	201	265
Running 9-5/8” Casing	292	581
Drilling 8-1/2” Hole	214	324
Running 7” Liner	169	371

Table 18 Summary of Max Pick Up Weight and Overpull Margins

5.7 Well Geohazards

The shallow section (defined as 1000m below mudline) of the Endurance field is generally considered favourable for drilling, based on the preliminary assessment of the 3D exploration dataset, 2DHR data and the results from nearby wells. Shallow gas is not expected to be a significant constraint to drilling. Generically, there is little

[3] Based on 80% of yield stress

indication of potential shallow gas on the available seismic data throughout the area, and none was encountered in any of the offset wells.

Holocene sediments at seabed in the Endurance area are mobile under the currently tidal influenced conditions, locally forming bedforms such as mega ripples and sand waves. These have been observed to be ~10m in amplitude in the 2DHR data but are poorly constrained on the 3D exploration data. Multibeam Echosounder and side scan sonar would better quantify the potential impact of bedforms. Gravel deposits or lags directly above bedrock (typically the Quaternary glaciogenic Boulders Bank formation) may be present, and the bedrock itself may outcrop in seabed troughs.

Glaciogenic features, such as outwash channels and plains, eskers and kames lead to significant thickness and lithological variations in the Quaternary geology. Local occurrence of drop stones, cobbles, gravels and unconsolidated zones is poorly constrained on the 3D dataset. Hi-res sub-bottom profiler is needed to better constrain these features, however at least 3 outwash channels have been identified in the vicinity of Endurance. The presence of sand at the seabed, and potential for gravels, boulders and shallow hard layers may affect conductor installation.

Below the Quaternary glaciogenic sediments is Jurassic aged strata, which was uplifted and eroded during Tertiary mobilisation of the Zechstein salts. The stratigraphy comprises predominantly of Early Jurassic interbedded shales, sands and marls of the Lias formation, although depending on well placement, the sandier West Sole formation may be encountered. The area is heavily faulted related to the Tertiary uplift. There is potential for incurring losses, BHA and casing hang up while drilling through the faults. Due to the age of the rocks throughout the shallow section (as opposed to normal marine clastics), there is potential for variable gauge hole, tights spots, and ledging. bit balling and gumbo have also contributed to NPT while drilling through Lias shales.

5.8 Casing Design Summary

BP casing design has been completed to show feasibility of well execution using standard North Sea specification casing where possible. The only exception to this being the 9-5/8" production casing which, due to corrosion risk, will be SM25Cr. The plan for Net Zero Teesside at the time of writing is to drill vertical subsea wells. To ensure the BoD outlines the edge of the design envelope, both the deepest well - Injector CI4 which has a deviated trajectory - and the shallowest well - OW1 which is vertical - have been examined to ensure the worst case loads are covered leaving the largest possible design envelope.

Casing	OD (in)	ID (in)	Grade	Weight (lb/ft)	Conn	Burst (psi)	Collapse (psi)	Tensile (klb)
Conductor	30	28	X-56	310	Merlin	3267	1681	5102
Conductor	20	18 3/4	X-56	133	Merlin	3060	1450	2130
Surface / Inter	13 3/8	12.415	L80	68	VAM TOP	5024	2263	1555
Production	9 5/8	8.535	SM25CRW-125	53.5	VAM TOP	7930	6620	1244
Production Liner	7	6.184	SM25CRW-125	29	VAM TOP	13110	9110	1056

Table 19 Casing Design Summary

String	OD/Weight/Grade	Connection	CI4 Interval (mMDBRT)	OW1 Interval (mTVD/MDBRT)	Minimum Safety Factor (Abs)				Governing Loads
					Burst	Collapse	Axial	Triaxial	
Conductor Casing	30", 310ppf, X-56	Lynx HDHT	85 - 172	85 - 172			5.873 - 5.918	D 5.798 - D 5.832	Axial, Triaxial - Running in Hole
	20", 129 ppf, X-56	RL-4S	85 - 172	85 - 172			2.541 - 6.230	D 2.515 - D 6.072	
Surface Casing	13 3/8", 68 ppf, P-L80	Vam Top	85 - 690	85 - 620	2.755 - 3.388	2.516 - 3.557	2.816 - 4.337	D 2.787 - D 4.300	Burst - Bullhead kill - Start Collapse - WCD collapse Axial - Overpull force, (300 klbf) Triaxial - Overpull force, (300 klbf)
Production Casing	9 5/8", 53.5 ppf, SM25CRW-125	Vam Top	85 - 1759	85 - 1106	2.204 - 2.250	4.502 - 4.828	3.58 - 4.362	2.338 - 2.396	Burst - Pressure Test (5000psi over 1.38sg MW) Collapse - WCD collapse Axial - Overpull force, (300 klbf) Triaxial - Pressure Test (5000psi over 1.38sg MW)
Production Liner	7", 29 ppf, SM25CRW-125	Vam Top	1609 - 2342 (TD)	956 - 1,290 (TD)	3.606 - 3.861	3.903 - 4.527	3.381 - 3.399	D 3.197 - D 3.237	Burst - Pressure Test (2,900psi on 1.36sg) Collapse - WCD collapse Axial - Overpull force, (300 klbf) Triaxial - Overpull force, (300 klbf)

Table 20 Minimum Safety Factors (CI4 and OW1)

Table 21 shows the range of Safety Factors for the deepest well - Injector CI4 - and the shallowest well - OW1. Although Safety Factors for the crestal OW1 well could be expected to be lower than the deeper CI4 well due to having a smaller column of fluid to provide overbalance, the shallower shoe depths in the OW1 well actually result in the Safety Factors for the governing loads being more conservative.

The range is small, so a sensitivity was performed taking the highest case ppfg from the OW1 well and using it in the CI4 well design. Table 22 shows the collapse, axial and all but the 9-5/8" triaxial governing loads are the same in both wells, while the burst and 9-5/8" triaxial governing loads differ slightly.

String	OD/Weight/Grade	Connection	MD Interval (m)	Minimum Safety Factor (Abs)				Governing
				Burst	Collapse	Axial	Triaxial	
Conductor Casing	30", 310ppf, X-56	Lynx HDHT	85 - 172			5.873	D 5.798	Axial, Triaxial - Running in Hole
	20", 129 ppf, X-56	RL-4S	85 - 172			2.541	D 2.515	Collapse - Cementing
Surface Casing	13 3/8", 68 ppf, P-L80	Vam Top	85 - 690	2.685	2.516	2.816	D 2.787	Burst - Bullhead kill - Start Collapse - WCD collapse Axial - Overpull force, (300 klbf) Triaxial - Overpull force, (300 klbf)
Production Casing	9 5/8", 53.5 ppf, SM25CRW-125	Vam Top	85 - 1759	2.234	4.502	3.580	2.375	Burst - Pressure Test (5000psi over 1.38sg MW) Collapse - WCD collapse Axial - Overpull force, (300 klbf) Triaxial - Pressure Test (5000psi over 1.38sg MW)
Production Liner	7", 29 ppf, SM25CRW-125	Vam Top	1609 - 2342 (TD)	3.799	3.903	3.381	D 3.197	Burst - Pressure Test (2,900psi on 1.36sg) Collapse - WCD collapse Axial - Overpull force, (300 klbf)

Table 21 Minimum Safety Factors (CI4 with high case ppfg)

5.8.1 Casing Design Results (Stress Analysis)

The summary of governing loads shows the proposed casing design is suitable for all locations and potential shoe depths across the field.

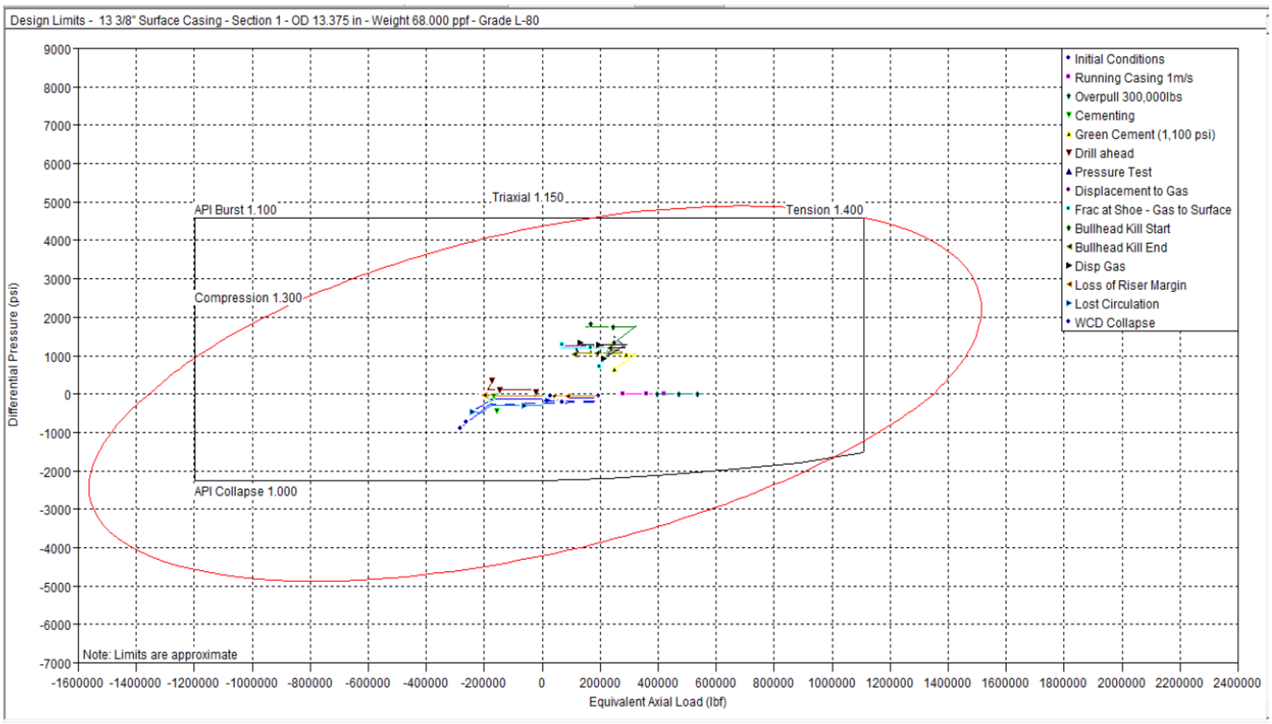


Figure 31 13-3/8" Surface Casing Design Limits Plot

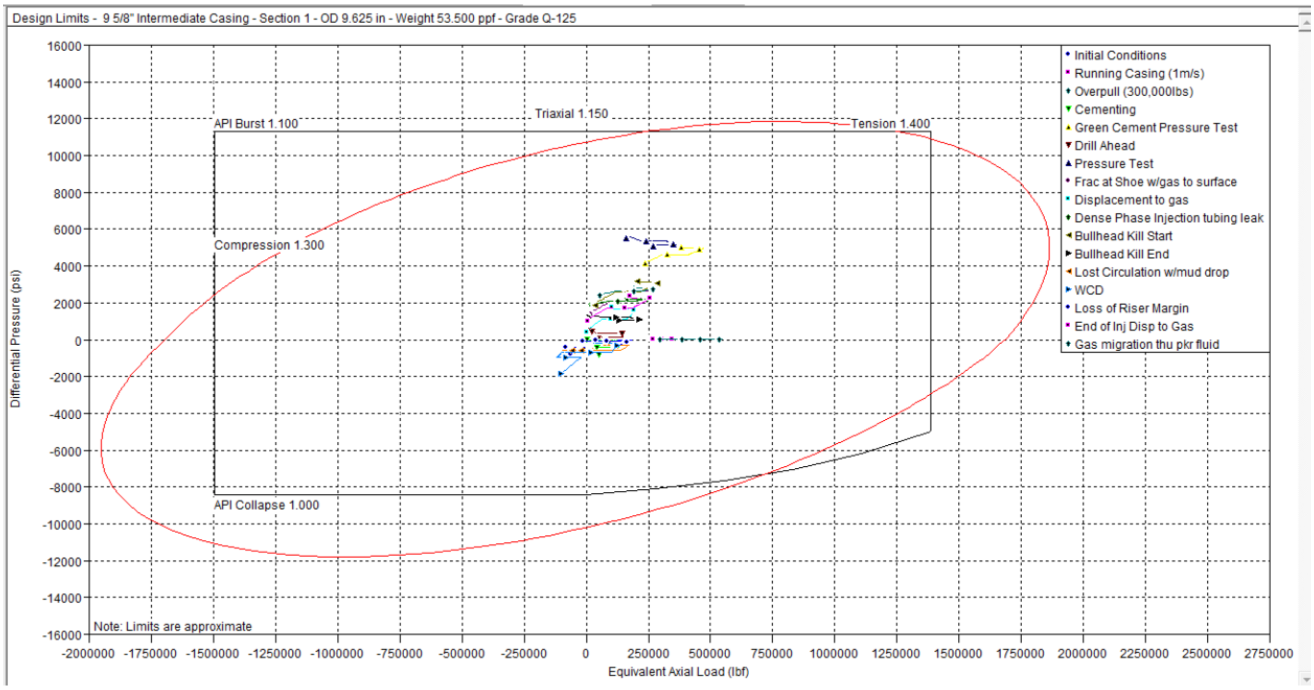


Figure 32 9-5/8" Production Casing Design Limits Plot

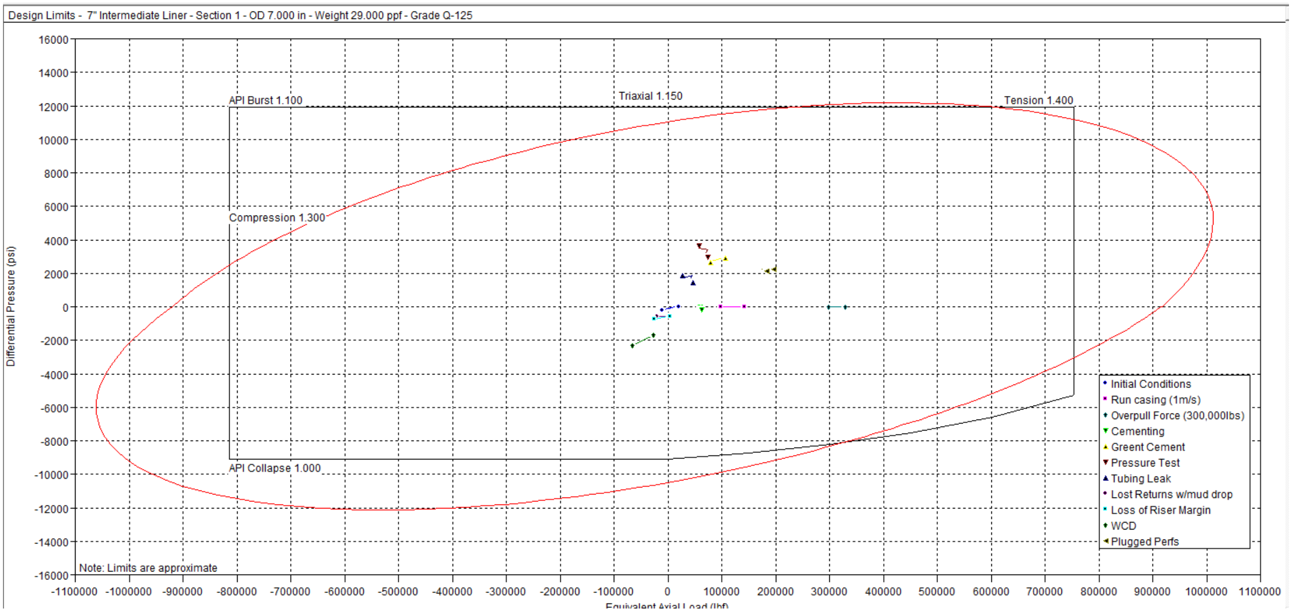


Figure 33 7" Production Liner Design Limits Plot

5.8.2 Casing Programme

20” x 30” Conductor

The conductor string with 6 joints below the seabed would be set on depth, based on the length of conductor joints, at ±172m MDBRT. The bottom of the conductor would be swaged to 20in OD, in line with the slim design of this well. It is planned to cement the conductor back to the mudline with 300% excess cement. A riser analysis would be carried out on the 310 lb/ft 30in OD conductor during detailed design to check the suitability of the planned conductor string design.

13 3/8” Surface Casing

The 13⅜in, 68lb/ft, L80 VAM TOP surface casing is planned to be set in the Lias formation; this would isolate most of the reactive Lias formation. The casing setting point would be set on depth. The BOP stack would be installed after running the casing, allowing the mud system to be swapped to LTOBM and the mud weight to be increased to drill the deeper formations.

9-5/8” Production Casing

A 9⅝in, 53.5lb/ft, SM25CRW-125, Super Duplex VAM TOP injection (production) casing string would be run and set 20m above the Rot Clay cap rock in the Rot Halite formation. The 9⅝in would cover most of the potential mobile salt sections allowing the Rot Halite, Rot Clay and Bunter Sandstone to be cored. It would also provide an injection (production) conduit with sufficient burst, collapse and tensional strength to withstand the loads from any injection scenario. The casing setting depth could be moved higher up the well, in the Rot Halite should future abandonment requirements (for improved store integrity to CO2 leakage) dictate the need for a larger cement ‘pancake’ plug above the Rot Clay cap rock.

Liner

Two liner options are carried; a 5 ½” 23lb/ft as a reference case, and a 7”, 29lb/ft liner for an option to include DTS across the reservoir which will be finalised in the run-up to FEED. In both cases, SM25CRW-125 Super Duplex VAM TOP tubulars would be specified. A liner to overlap of (150m) would be incorporated and the string cemented to top liner hanger with CO2 resistant cement. The VAM TOP connection would be specified so that the liner can be rotated during the cement job whilst the 25 Chrome Super Duplex liner would be specified for its inert nature and CO2 resistant properties.

5.9 Fluids Design Summary

Water based muds have been used to drill the upper hole sections (represented by 17-1/2in diameter hole but sometimes drilled in 26in and then 16in) and although historically sea water and sweeps has been used, this proved problematic and the use of inhibitive mud formulations such as Polyglycol and KCl polymer were used latterly.

In the lower hole sections, represented by 12¼in diameter hole and 8½in sections both Oil Based Mud (OBM) and salt saturated muds have been used, but due to improved hole properties and more efficient drilling, the OBMs have prevailed more recently. The following demonstrates that a satisfactory fluids design is achievable but detailed selection of OBM vs WBM for the lower sections should be left for the detailed design phase in FEED.

Hole Section	Mud	Density (sg)	Comments
26” x 36” (riserless)	Seawater with viscous bentonite sweeps. Displacement bentonite mud	1.20 sg	Hi-vis bentonite sweeps used to aid hole cleaning. At TD, pump 100bbl hi-vis pill and displace to 1.20sg bentonite mud before POOH to provide wellbore stability running conductor
17 1/2”	KCl or Polyglycol WBM	1.14 to 1.32 sg	Addition of shale inhibitor to reduce bit balling and provide enhanced cuttings encapsulation for the potentially troublesome Lias formation. Bit balling has been an issue on offset wells therefore sufficient pills / sweeps should be available and pumped frequently especially drilling the build section
12 1/4”	LTOBM	1.32 to 1.38 sg	Drilled through the Haisborough group to ±20m from the base of the Rot Halite formation. A LTOBM used to provide inhibition through the shale formations and also to help maintain wellbore stability. Although normally-pressured, the mud weight should be 1.32 to 1.38 sg to mitigate potential salt mobility
8 1/2”	High Performance WBM	1.20-1.26 sg	Mud weight 1.20 to 1.26 sg with calcium carbonate to prevent losses to the Bunter sandstone and mitigate the risk of differential sticking.

Table 22 Example Mud Programme Summary

5.9.1 Top Hole Section

The 36in x 26in diameter hole section would be drilled with seawater pumped at maximum pump rate. Pre-hydrated bentonite sweeps would be pumped at each connection and mid-stand, or as hole conditions dictate to TD at ±172mMD BRT. At section TD, the hole would be circulated clean with a 100bbl pill and displaced to a 1.20sg bentonite mud prior to carrying out a wiper trip and then re-displacing prior to pulling out of hole to run the conductor. The 1.20sg mud would aid wellbore stability while running the conductor.

Hi Visc Sweep Formulation		Displacement Mud Formulation	
Drill Water	0.966 bbl	Drill Water	0.923 bbl
Bentonite	25 ppb	Bentonite	20 ppb
Caustic Soda	0.125 ppb	Caustic Soda	0.125 ppb
Soda Ash	0.125 ppb	Soda Ash	0.125 ppb
Viscosifier	As required	Barite	73.7 ppb

Table 23 Top Hole Mud Section

5.9.2 17 ½" Section

The 17 ½" diameter hole section would be drilled with a 1.14-1.20sg KCL Water Based Mud (WBM) system. Additions of shale inhibitor would be added to reduce bit balling potential and provide enhanced cuttings encapsulation for the potentially troublesome Lias formation. Bit balling has been a major issue on offset wells therefore sufficient pills / sweeps would be available and should be pumped frequently while drilling the build section. This system provided the required inhibition to successfully drill the section and run 13 ⅜in casing to TD on the 42/25d-3 appraisal well. Refer to **Table** 27, KCl Polyglycol mud formulation.

Product	Function	Concentration
Water	Volume	0.510 bbl
KCL Brine	Inhibition	0.417 bbl
Soda Ash	Calcium Remover	0.125 ppb
Caustic Soda	pH Control	0.125 ppb
Biopolymer viscosifier	Viscosifier + Suspension Agent	1 ppb
Polyanionic cellulose	Fluid Loss Control	1.5 ppb
Drilling Starch	Fluid Loss Control	2.0 ppb
Biocide	Biocide	0.001 ppb
Micronised Barite	Weighting Agent	35.588 ppb
Polyglycol	Inhibition	13.9 ppb
Polymeric shale inhibitor	Encapsulator	1.5 ppb

Table 24 17 ½" Hole KCL Polyglycol Formulation

Parameter	Volume
Mud Weight (sg)	1.32
PV (120 F)	ALAP
YP (120 F)	20 to 35
Fann 6 (120 F)	10 to 15
Gels (10s/10m)	10 to 20 / 15 to 25
HTHP Fluid Loss (250 F)	<5.0 ml
Electrical Stability (V)	>400
WPS Chlorides (g/l)	210 to 240
Excess Lime (ppb)	>1.0
OWR	73/27 to 77/23

Table 25 17 ½" Hole Mud Properties

5.9.3 12 ¼" Section

The 12 ¼" section will be drilled through the Haisborough group to ±20m from the base of the Rot Halite formation. A Low Toxic Oil Based Mud (LTOBM) will provide inhibition while drilling through the shale formations and also help maintain wellbore stability. Although normally pressured, the mud system will be 1.32-1.38sg to prevent salt mobility.

Note: An inhibited water based mud system would also be capable of drilling the section, should waste management look like an area of high WOW / NPT potential. Refer to **T**able 29, showing example LTOBM mud formulations.

Product	Function	Concentration
Water	Discontinuous Phase	0.191 bbl
Base Oil	Continuous Phase	0.591 bbl
Organophilic clay	Viscosifier + Material Suspension	5.0 ppb
LTOBM emulsifier	Primary Emulsifier	11.0 ppb
Polymer	Fluid Loss Control	1.5 ppb
Lime	Alkalinity	8.0 ppb
Micronised Barite	Weighting Agent	145.42 ppb
Calcium Carbonate	Bridging Agent	20 ppb

Table 26 12 ¼" Hole Formulation

Parameter	Volume
Mud Weight (sg)	1.32
PV (120 F)	ALAP
YP (120 F)	20 to 30
Fann 6 (120 F)	14 to 16
Gels (10s/10m)	10 to 20 / 15 to 30
HTHP Fluid Loss (250 F)	<3.0 ml
Electrical Stability (V)	>400
WPS Chlorides (g/l)	55 to 80
Excess Lime (ppb)	1.0 – 3.0
OWR	70/30 to 80/20

Table 27 12 ¼" Hole Mud Properties

5.9.4 8 ½" Hole Reservoir Section

An extensive coring and logging programme is planned for the 8 ½in section including coring the Bunter Sand formation. A new LTOBM mud system would be used for the 8 ½in section to increase the likelihood of attaining the full data acquisition programme. A mud weight of 1.20-1.26sg would be used and calcium carbonate added to the system in order to prevent losses to the Bunter Sand and mitigate the risk of differential sticking. Given that the evaluation period could potentially last up to 1 week, the use of LTOBM would aid in maintaining a good hole condition. Refer to   **T**able 31, showing example LTOBM mud formulations.

Note: An inhibited water based mud system would also be capable of drilling the section, should waste management look like an area of high WOW / NPT potential. Refer to **T**able 29, showing example LTOBM mud formulations.

Product	Function	Concentration
Water	Discontinuous Phase	0.194 bbl
Base Oil	Continuous Phase	0.599 bbl
Calcium Chloride	Water Phase Salinity	30.056 ppb
Organophilic clay	Viscosifier	5.0 ppb
LTOBM Emulsifier	Primary Emulsifier	6.0 ppb
LTOBM Emulsifier	Secondary Emulsifier	6.0 ppb
Asphaltic resin	Fluid Loss Control	1.5 ppb
Lime	Alkalinity	8.0 ppb
Micronised Barite	Weighting Agent	114.06 ppb
Calcium Carbonate	Bridging Agent	30 ppb

Table 28 8 ½" Hole LTOBM Formulation

Parameter	Volume
Mud Weight (sg)	1.20
PV (120 F)	ALAP
YP (120 F)	15 to 25
Fann 6 (120 F)	8 to 15
Gels (10s/10m)	10 to 20 / 15 to 25
HTHP Fluid Loss (250 F)	<3.0 ml
Electrical Stability (V)	>600
WPS Chlorides (g/l)	210 to 240
Excess Lime (ppb)	>1.0
OWR	73/27 to 77/23

Table 29 8 ½" Hole Mud Properties

5.9.5 Drilling Waste Management

For the 17 ½” section drilled with WBM, cuttings will be returned to the rig and discharged to the sea.

For the 12 ¼” and 8 ½” sections with drilled with LTOBM, the assumption is that cuttings will be returned to the rig and skipped and shipped back to shore for treatment and disposal.

An initial estimate of the amount of drilled cuttings waste has been provided to the Environmental team based on the following assumptions:

- Water depth: 60m
- 36” hole: 132mTVDss (Sea water and sweeps)
- 17-1/2” hole: 550mTVDss (WBM)
- 12-1/4” hole: 1157mTVDss (SOBM)
- 8-1/2” hole: 1564mTVDss (SOBM)

The volume of WBM expected to be consumed per well is 5,500 bbl. The volume of OBM expected to be consumed per well is 2,200 bbl. The expected volume of cuttings per well is 250 m3 which would be approx. 650 MT. NORM (Normally Occurring Radioactive Material) contamination is not expected on the fluids or cuttings.

5.10 White Rose Cementing Design Summary

Casing cement work presented in this section is based on the well engineering work done for the White Rose Project as an example cement design, as detailed work has not yet been carried out for the subsea NEP wells. It should be noted that the concept for the White Rose Project was to drill deviated platform wells from a NUI. NEP will drill vertical subsea wells, hence the applicability is limited but it demonstrates that a satisfactory cementing design is achievable.

5.10.1 20” x 30” Conductor

For structural support, the 30in x 20in conductor will be cemented to the mudline with 16.0ppg Class G cement. This will be an inner string job with an open hole excess of 300%. A 20bbl seawater / dye spacer should be pumped ahead of the cement to detect returns at the seabed.

Composition	Value
Lafarge Class G	
Calcium Chloride Liquid	0.54 gal/sk
Seawater	4.65 gal/sk
NF-6	10pts/10bblMR

Table 30 Conductor Cement Composition (White Rose)

Property	Value
Surface Density	16.00 ppg
Surface Yield	1.17 ft3/sk
Total Mixing Fluid	5.21 gal/sk
Thickening Time (70 Bc)	5:00+
Free Water Vert at 48 deg F	0%
Pv/Yp at 48 deg F	30/64 (cp/lb/100ft3)
Compressive Strength at 46 deg F	50 psi in 8 hours
Compressive Strength at 46 deg F	500 psi in 12 hours

Table 31 Conductor Cement Properties (White Rose)

5.10.2 13 3/8" Surface Casing

The surface casing will be cemented with 13.5 ppg lead and 16.0 ppg tail slurries. Both slurries will be Class G cement and will be displaced by a single wiper plug. A 75% open hole excess should be pumped with top of cement at +/-457m.

Composition	Value
Lafarge Class G	
Silicalite Liquid	1.0 gal/sk
CFR-8L	0.5 gal/sk
HR-4L	0.15 gal/sk
Fresh Water	3.77 gal/sk
NF-6	10pts/10bblMR

Table 32 Surface Casing Cement Composition (White Rose)

Property	Value
Surface Density	16.00 ppg
Surface Yield	1.20 ft3/sk
Total Mixing Fluid	5.43 gal/sk
Thickening Time (70 Bc)	4:00+
Free Water Vert at 48 deg F	0%
Pv/Yp at 48 deg F	53/82 (cp/lb/100ft3)
Compressive Strength at 46 deg F	50 psi in 8 hours
Compressive Strength at 46 deg F	500 psi in 12 hours

Table 33 Surface Casing Cement Properties (White Rose)

5.10.3 9 5/8" Production Casing

The 9⅝" casing will be cemented to a TOC of ±914m MDBRT with Class G 13.5ppg lead and 16.0ppg tail cement. This will isolate the majority of the mobile salt sections drilled in the 12¼" section. An open hole excess of 50% should be pumped as part of a dual plug cement job.

Composition	Value
Lafarge Class G	
Halad-300L NS	0.6 gal/sk
HR-4L	0.08 gal/sk
Silicalite Liquid	1.0 gal/sk
CFR-8L	0.5 gal/sk
Fresh Water	4.99 gal/sk
NF-6	10pts/10bblMR

Table 34 9 5/8" Casing Cement Composition (White Rose)

Property	Value
Surface Density	15.00 ppg
Surface Yield	1.37 ft3/sk
Total Mixing Fluid	6.69 gal/sk
Thickening Time (70 Bc)	4:00
Free Water Vert at 48 deg F	<1%
Pv/Yp at 48 deg F	135/45 (cp/lb/100ft3)
Compressive Strength at 46 deg F	50 psi in 8 hours
Compressive Strength at 46 deg F	500 psi in 14 hours

Table 35 9 5/8" Casing Cement Properties (White Rose)

5.10.4 7" Injection Liner

The NEP liner cement design has been tailored to the requirements of dispatchability; however, the White Rose design is presented for completeness as a companion to the casing cement design above.

The 42/25d-3 appraisal well used Halliburton CorossaCem NP (Thermalock) slurry to cement the 7in liner to ensure that no carbonation takes place when the cement is exposed to CO_2. However, the expected temperature fluctuations in the project injection wells require addition of fibres to the cement recipe for elasticity. Thermalock cement cannot be mixed with Portland cement and therefore has to be stored in clean tanks and pumped through clean lines to avoid contamination.

Schlumberger's EverCRETE retains its integrity under exposure to the most critical CO_2 conditions, having predictable mechanical properties on its full range of density. EverCRETE is compatible with Portland based systems, therefore eliminates any associated risk of contamination when handling and storing offshore.

Verification of the placement and zonal isolation effectiveness should be done with azimuthal cement bond logging.

Composition	Value
EverCrete	
Fe2	0.70% BWOC
Latex 2000	2.0 gal/sk
SA-1015	0.1% BWOC
Fresh Water	2.89 gal/sk
NF-6	10pts/10bblMR

Table 36 Liner Cement Composition (White Rose)

Property	Value
Surface Density	15.00 ppg
Surface Yield	1.21 ft3/sk
Total Mixing Fluid	4.96 gal/sk
Thickening Time (70 Bc)	7:00
Free Water Vert at 111 deg F	0%
Fluid Loss at 111 deg F	20cc/30 min
Pv/Yp at mix	60/30 (cp/lb/100ft3)
Pv/Yp at 111 deg F	60/30 (cp/lb/100ft3)
Compressive Strength at 46 deg F	50 psi in 10 hours
Compressive Strength at 46 deg F	500 psi in 16 hours

Table 37 Liner Casing Cement Properties (White Rose)

5.11 NEP Cementing Design Summary

This section presents cement design specific to the liner on NEP CO2 injection wells. Further work will be undertaken to design the casing cement jobs in the run-up to FEED / Define.

A review of cementing design and industry practices was carried out to determine if specialist cements (as opposed to standard Portland cements) would be required for the NZT/NEP project.

Numerous studies and papers have been published over the years, and the conclusion is that effective zonal isolation can be achieved using standard oilfield Portland cement blends. Non-Portland based, specialised CO2 resistant cement slurries for CO2 injection or storage wells are not recommended, as the marginal advantages offered in CO2 resistance are offset by the difficulties in mixing and placing them reliably.

Note that published cement analysis work to date generally considers temperatures below 225 deg F (107 deg C) and pressures below 3000 psi. Endurance fits within this envelope.

5.11.1 Cement Type Recommendations

- Effective zonal isolation can be achieved using standard oilfield Portland cement blends. Non-Portland based, specialised CO2 resistant cement slurries for CO2 injection or storage wells are not recommended, as the marginal advantages offered in CO2 resistance are offset by the difficulties in mixing and placing them reliably.
- Portland cements with non-reactive filler (such as fly ash or silica), low permeability and non-shrinking properties can achieve effective zonal isolation in CO2 injection wells for EOR or CCS. A low water ratio is also used to reduce the permeability of the cement.
- It is expected to take millions of years for CO2 to degrade a 100m sheath of well-bonded Portland based cement. However, in the presence of a micro-annulus or larger defects in the cement, the degradation process will be significantly faster. To avoid the creation of such defects it is important that the casing is well centralised, mud removal is good and there is efficient cement placement.
- The cement needs to be designed for the stresses it will see during the life of the well to maintain integrity of the cement sheath. Enhanced mechanical property cement with expanding additives can be used to withstand the downhole stress states expected.
- It is important to differentiate the wells to be drilled for CO2 injection from those already drilled in the field. New wells can be designed with a defect-free slurry. Existing wells need measures in place to log, monitor and remediate ineffective isolation from acid gas.
- Industry organizations such as BSEE and API as well as major operators, have supported comprehensive studies on CO2 well integrity concerns and found a low risk for impaired well integrity such as potential corrosion of pipe and cement exposed to wet-CO2 induced acidic conditions. Such studies conclude that there are fit for purpose cement designs using Portland cement. Views that CO2 can leak through cement in the short term are often ill-conceived and not based on accurate downhole conditions. The matrix permeability to CO2 for properly designed Portland cements is effectively zero.
- The recommendation is supported by field experience where CO2 was produced or injected in wells cemented with conventional Portland cement blends and evidences showing that neither the cement was degraded, or zonal isolation was lost.

5.11.2 Cement Placement

Cement placement is important for CO_2 zonal isolation. A defect such as a channel or a wormhole occurring during placement or post-placement may constitute a leak path; therefore strict adherence to cementing best practice and post-job cement evaluation are key.

5.11.3 Cement Job Objectives

The Top of the DPZ (Bunter) is at 1,921 m MD, the optimum objective is to get unchanneled cement to the Top of Liner, while the minimum objective is to get 30 m of cement, confirmed by circumferential logging, above the top of Bunter.

Objective	Description	TOC Requirement	Method of Verification
Minimum	Top of circumferential cement 30 m above Top of Bunter: 1,891 m MD) Liner Top Packer tested	1,891 m MD	Logging
Desired	Top of cement 100 m above Top of Bunter: 1,791 m MD) Liner Top Packer tested	1,791 m MD	Logging / Lift Pressure/ Volumetric
Optimum	Top of cement above TOL: 1760 m Liner Top Packer tested	1,760 m MD	Logging / Lift Pressure/ Volumetric/ TOL

Table 38 Cement Job Objectives

5.11.4 Liner Cement Placement Simulations

In the cementing placement simulations, the 5 ½" (23 ppf) liner is set @ 2,543 m MD with the TOL set @ 1760 m MD. The shoe track length is 36 m (3 casing joints) The previous casing is a 9 5/8" (53.5 ppf) casing set @ 1,910 m. The liner running string is a 5" (19.5 ppf) drill pipe. The open hole is 8 ½" diameter with no annular excess.

The well is deviated with a maximum deviation of 60 deg at TD. This configuration (worst case scenario for cement placement), but as explained earlier in this report, the reference case is to drill vertical wells..

The minimum frac gradient across the 8 ½” section is 13.82 ppg EMW and the maximum pore pressure is 8.98 ppg EMW.

The mud is 11.35 ppg density with a plastic viscosity of 35 cP and a yield point of 11 lbs/100 ft2. The spacer is 13.0 ppg density with a plastic viscosity of 51 cP and a yield point of 16 lbs/100 ft2. The cement slurry is a 15.3 ppg Class K cement with a plastic viscosity of 90 cP and a yield point of 7 lbs/100 ft2. The cement slurry rheology is calculated from Fann rheometer readings and Hershel Buckley values are used in the simulations.

Fluid	Volume	Rate	Comment
Spacer	70	6 bpm	
Cement	135 bbl	5 bpm	TOC @ 1,580 m (no annular excess)
Top plug			
Mud	130	6 bpm	
Mud	25	4 bpm	

Table 39 Liner Cement Job Pumping Schedule

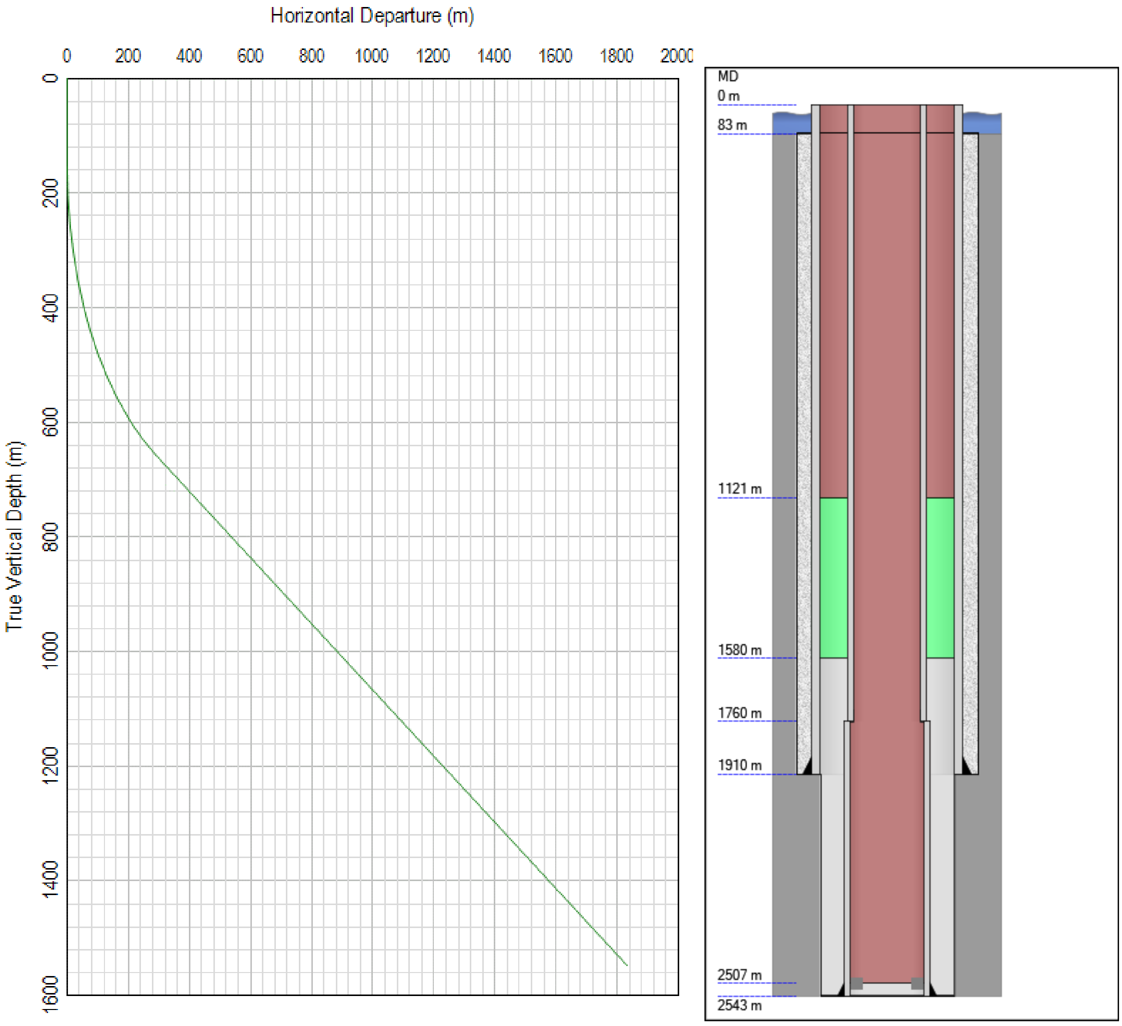


Figure 34 Liner Cement Simulation – Fluid Map

5.11.4.1 Cementing ECD

The maximum cementing ECD across the Bunter sand, at the end of the cement job, is 13.5 ppg which is 80 psi less than the theoretical frac gradient.

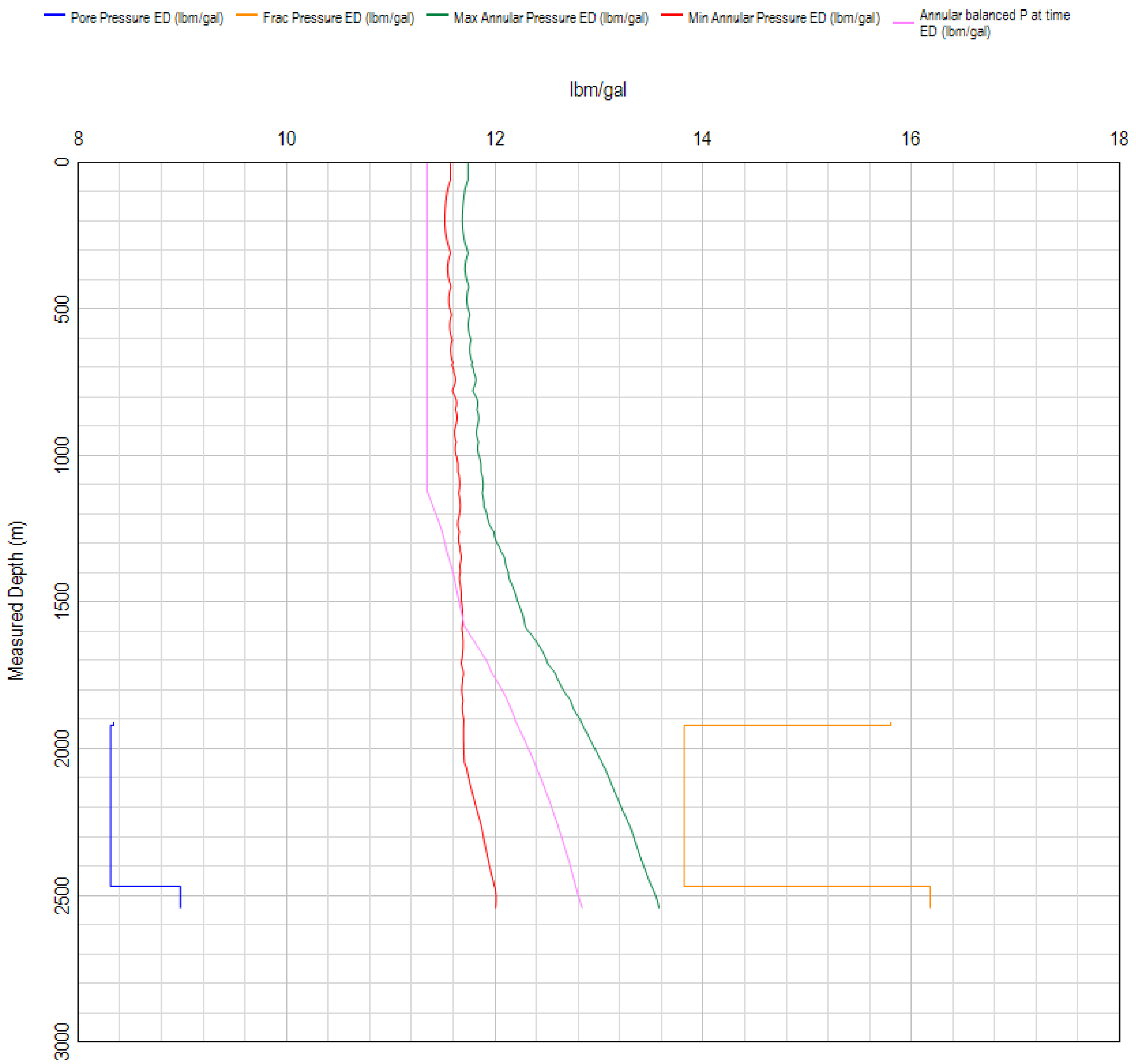


Figure 35 Liner Cement Job ECD

5.11.4.2 Liner Stand-Off

The stand-off calculation assumed a typical 5 ½" x 8 ½" one-piece bow centralizer with a placement pattern of one per joint with 2 centralizers on the last joint of casing. The minimum stand-off between centralizers is 73%.

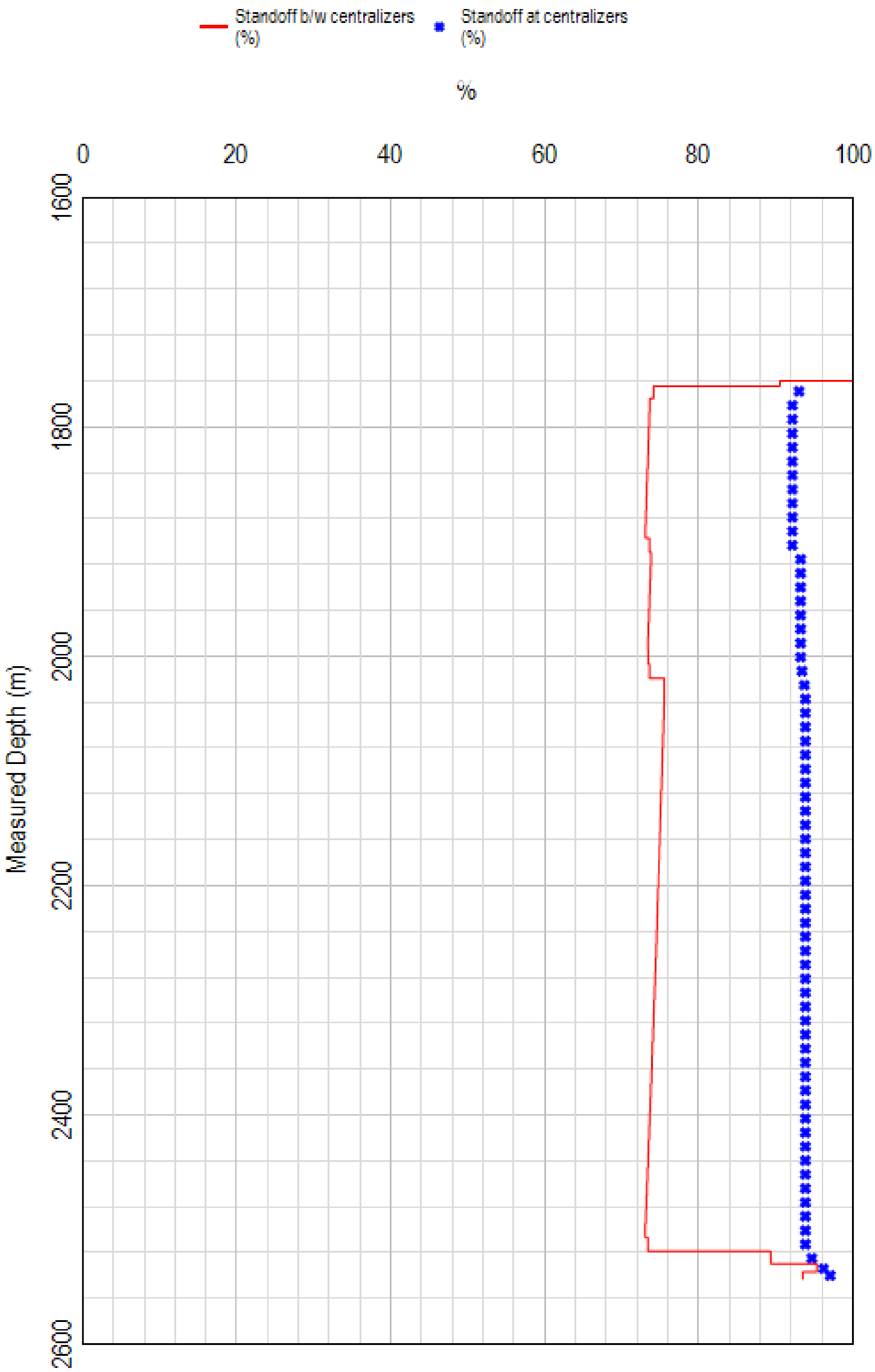


Figure 36 Liner Stand-Off

5.11.4.3 Mud Removal

The mud removal simulation assumes no bottom plug, only one top plug. With 5 ½” extra slim liner hanger system, it is recommended not to use a bottom plug based on experience with tight tolerance plug geometry. The simulation also assumes no rotation, but rotation is recommended and should be planned for.

Cement placement efficiency is above 99% up to 2,064 m MD m and 97% at the TOL.

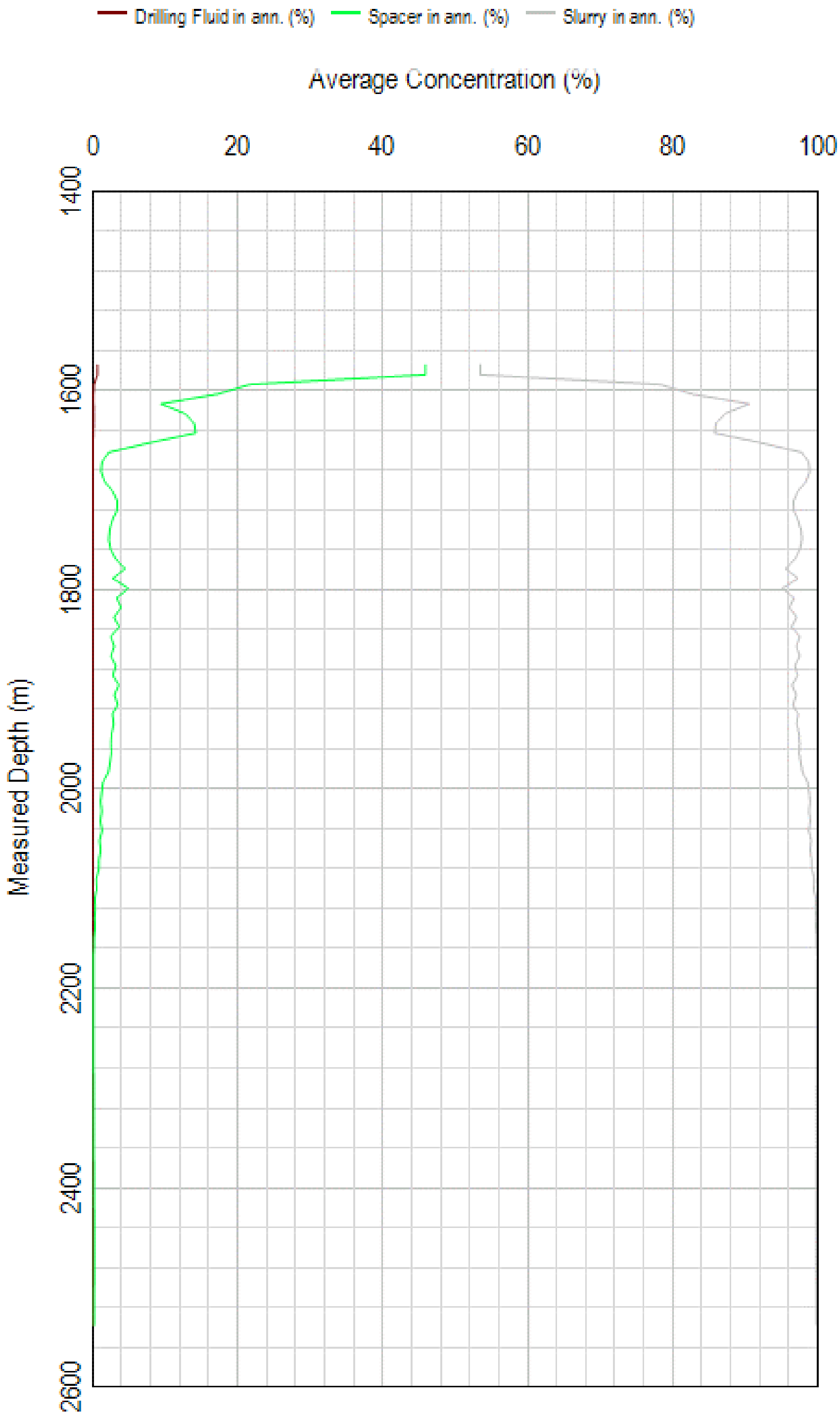


Figure 37 Mud Removal Efficiency

5.11.5 Cement Laboratory Testing (Preliminary)

A pilot test was carried out on the proposed cement formulation to check the hydraulic and cement integrity simulations. A Class K (Class G + 35% silica flour) with expanding properties was selected for a lower CO_2 footprint and reduced Portland cement composition.

This section presents a precis of the Baker Hughes report for information.

5.11.5.1 Pilot Test Input Data

Test Conditions:

BHST	150 deg F
BHCT	130 deg F
BHP	3,600 psi
Time to pressure and temperature	1 hr

Slurry properties:

Cement Class	Class K Cement
Density	15.3 ppg
Fluid Loss	<50 mL API
Free Fluid	Zero or traces
Thickening Time	5 -7 Hrs
Linear Expansion (API Ring test)	0.2% minimum - 1% maximum after 7 days

5.11.5.2 Pilot Laboratory Testing Report

Baker Hughes

BP
Request ID: 256535
Baker Hughes Request Description: Net Zero Teeside Project
Approved Date: 25-Sep-2020

CLIENT/WELL INFORMATION

Client Name	BP			**District**	Aberdeen
Well Name	CO2 Injection	**MD**	3,300 m	**Date Requested**	19/08/2020
Well Type	Deviated	**TVD**	1,800 m	**Date Result Needed**	02/09/2020
Well Location	North Sea	**GG**	5.00 °C/100m	**Tubing Size**	
Job Type	Not Required	**WD**	143m	**Casing Size**	
Job Description	Cement system for CO2 Injection	**BHST**	150.00 °F	**Mud Type**	Water-Based
UWI		**Surface Temper**	80.00 °F	**Mud Density**	11.30 ppg
Rig #	N/A	**BHCT**	130.00 °F	**Mud Density**	

SLURRY DESIGN

Slurry ID	256535-002	**Slurry Type**	Pilot	**Slurry Description**	TAIL

SLURRY PROPERTIES

256535-002 | TAIL

Slurry	15.30 ppg	**Liquid Volume**	59.78 %
Slurry Yield	1.69 ft³/sack	**Total Mix Fluid**	7.58 gal/sack
Mix Water	6.23 gal/sack		

SLURRY COMPOSITION

256535-002 | TAIL

Component Type	Component	Concentration	Lot/Batch	Source
Water	Fresh Water	55.262 %	LS TAP	1-Lab
Additive	FP-16LG	0.020 gal/sack	LAB FP843G2	2-Lab
Additive	ASA-304L	0.020 gal/sack	LS AS101GM	3-Lab
Additive	BA-58L	0.800 gal/sack	LAB stock	4-Lab
Additive	Ultra 7LN	0.400 gal/sack	LS CY91901001	5-Lab
Additive	R-12L	0.110 gal/sack	LAB 91900573	6-Lab
Additive	EC-2	1.000 %BWOC	LAB stock	7-Lab
Base	Cement, Class G Dyckerhoff	100.000 %	LS 1215027	8-Lab
Additive	S-8, Silica Flour	35.000 %BWOC	LS 1215707	8-Lab

Baker Hughes

BP
Request ID: 256535
Baker Hughes Request Description: Net Zero Teeside Project
Approved Date: 25-Sep-2020

256535-002 | TAIL

Profile:	Thickening Time	Description:	Run normal conventional TT test. Ramp time 1hr

Start Temperature	End Temperature	Time To Temperature
80.00 °F	130.00 °F	1.00 hr
Start Pressure	**End Pressure**	**Time To Pressure**
100.00 PSI	3,600.00 PSI	1.00 hr

Results:	Thickening Time	Analyst:	GORDNIA
		Equipment:	CON157R
Test Temperature		130.0 °F	
Test Pressure		3600 psi	
Initial Bc		7 Bc	
30 Bc		05:33 hh:mm	
40 Bc		05:42 hh:mm	
50 Bc		05:45 hh:mm	
70 Bc		05:48 hh:mm	
100 Bc		05:51 hh:mm	

256535-002 | TAIL

Profile:	Compressive Strength - Non Destructive	Description:	Run CS- pre condition in HPHT consistometer for 1hr,then put in

Start Pressure	End Pressure	Time To Pressure
0.00 PSI	3,600.00 PSI	0.00 hr
Start Temperature	**End Temperature**	**Time To Temperature**
130.00 °F	150.00 °F	1.00 hr
Start Temperature	**End Temperature**	**Time To Temperature**
150.00 °F	150.00 °F	167.00 hr
Start Pressure	**End Pressure**	**Time To Pressure**
3,600.00 PSI	3,600.00 PSI	168.00 hr

Results:	Compressive Strength - Non Destructive	Analyst:	GRAYPAT01
		Equipment:	SGSA1245
12 hr		1495 PSI	
24 hr		2083 PSI	
50 psi		04:15 hh:mm	
500 psi		06:14 hh:mm	
Test Temperature		150.0 °F	

BP
Request ID: 256535
Baker Hughes Request Description: Net Zero Teeside Project
Approved Date: 25-Sep-2020

256535-002 | TAIL

Results:	Fluid Loss - Static Cell (Allen Set Screw)	Analyst:	GORDNIA
		Equipment:	FL02
Test Temperature		130.0 °F	
API Fluids Loss		26.0 cc	
Liquid Volume		13.0 cc	

256535-002 | TAIL

Results:	Free Fluid	Analyst:	GORDNIA
		Equipment:	FF
Test Temperature		130.0 °F	
Deviation Angle		45º	
Sample Volume		250 cc	
Liquid Volume		0.0 cc	
% Free Fluid		0.0 %	

256535-002 | TAIL

Results:	Static Gel Strength	Analyst:	GRAYPAT01
		Equipment:	SGSA1245
Test Temperature		150 °F	
Time from CSGS to 500 lb/100ft²		00:08 hh:mm	
Time to reach 100 lb/100ft²		03:17 hh:mm	
Time to reach 200 lb/100ft²		03:20 hh:mm	
Time to reach 300 lb/100ft²		03:23 hh:mm	
Time to reach 400 lb/100ft²		03:24 hh:mm	
Time from 100 to 500 lb/100ft² - Minutes		8 min	
Time to reach 500 lb/100ft²		03:25 hh:mm	

256534-002 | TAIL

Results:	Cement Expansion Ring	Analyst:	GORDNIA
		Equipment:	CuringChamber241
Curing Pressure		3600 psi	
Curing Temperature		150.0 °F	
Distance - Initial		12.04 mm	
Distance - Final		12.37 mm	
% Expansion		0.12 %	

Baker Hughes

BP
Request ID: 256535
Baker Hughes Request Description: Net Zero Teeside Project
Approved Date: 25-Sep-2020

256535-002 | TAIL

Results:	**Rheology - Temp 1**	**Analyst:**	GORDNIA
		Equipment:	Chan340
Mixability		4 (00:20 mm:ss)	
Test Temperature		72.0 °F	
API PV		112 cP	
API YP		7 lbf/100ft²	
10 sec Gel Strength		4.0 FDR	
10 min Gel Strength		10.0 FDR	

RPM	300	200	100	60	30	6	3
Up	115.0	84.0	50.0	33.0	20.0	6.0	4.0
Dwn		85.0	49.0	32.0	18.0	5.0	3.0
Avg		84.5	49.5	32.5	19.0	5.5	3.5

256535-002 | TAIL

Results:	**Rheology - Temp 2**	**Analyst:**	GORDNIA
		Equipment:	Chan340
Test Temperature		130.0 °F	
API PV		90 cP	
API YP		8 lbf/100ft²	
10 sec Gel Strength		4.0 FDR	
10 min Gel Strength		8.0 FDR	

RPM	300	200	100	60	30	6	3
Up	93.0	73.0	44.0	30.0	18.0	6.0	4.0
Dwn		68.0	40.0	27.0	16.0	6.0	5.0
Avg		70.5	42.0	28.5	17.0	6.0	4.5

256535-002 | TAIL

Results:	**Cement Slurry Conditioning - Atmospheric**	**Analyst:**	GORDNIA
		Equipment:	AtmConsist 441
Conditioning Temperature		130.0 °F	
Conditioning Ramp		Heat to 130F in 1 hour in atmospheric consistometer, condition at 130F for 30 minutes.	
Conditioning Time		30 min	

LAB NOTES

Fresh Water - Lab tap
FP-16LG - 815549
ASA-304L - 784976
BA-58L - 723034
Ultra 7LN - 844009
R-12L - 815546
EC-2 - 691002
S-8 - 784964
Class G cement - 805005

5.11.6 Start Up and Shut-Down for Dispatchability

For the onshore power station and capture plant to operate in a dispatchable mode (i.e. on and off or at varying rates with electricity production according to demand), the transportation and storage system (including the wells) must be able to do the same.

Starting and stopping injection of CO2 in the wells leads to pressure and temperature fluctuations. Of particular concern was the integrity of the cement under these fluctuating conditions. The bp Cement Integrity Simulator[4] has been used to simulate the effects of wellbore pressure and temperature changes on the cement by calculating the stresses in the cement sheath and checking if they exceed limits which could result in tensile, shear, disking or micro-annulus failure modes. The key assumptions, results and conclusions are summarised below.

Key Assumptions

- Ideal cement placement with no channelling or contamination
- Cement, formation and casing behave in a linear elastic manner
- Mechanical properties of the cement are from preliminary lab testing carried out by Baker Hughes in UK
- Deviated wellbore (60 degrees inclination)
- Cement is 15.3 ppg class K[5]. Class K cement is Class G + 35% silica flour
- Drilling fluid (reservoir section) 10.3 ppg (driven by WBS requirements for deviated well)
- Modelled casing stand-off is 50-100%
- 9-5/8” casing 53.5 ppf, P110 (set in Rot halite)
- 7” liner 29.0 ppf, P110 or 5-1/2” liner 20.0 ppf P110 (set in Bunter sandstone)
- Events modelled
  - Start CO2 injection (over 1 hour)
  - Steady state CO2 injection - wellbore cooling
  - Stop CO2 injection and shut in well (over 1 hour) – wellbore warming

[4] The BP Cement Integrity Simulator was developed as part of the Water Injection in Soft Sand Projects and was validated against large scale testing
[5] API Class K cement is a new API class of cement introduced to reduce cement manufacturing CO2 footprint. For more information, refer to API Spec 10A -25th Edition, March 2019, Addendum 1, November 2019-Annex B

Case	Description
A	7” Liner in 8-1/2” open hole with a regular 15.3 ppg Class K cement
B	5-1/2” Liner in 8-1/2”open hole with a regular 15.3 ppg Class K cement
C	5-1/2” Liner in 6-1/2”open hole with a regular 15.3 ppg Class K cement
D	7” Liner in 8-1/2” open hole with a regular 15.3 ppg Class K cement + expanding agent (0.36% volumetric expansion)
E	5-1/2” Liner in 8-1/2”open hole with a regular 15.3 ppg Class K cement + expanding agent (0.5% volumetric expansion)
F	5-1/2” Liner in a 6-1/2” open hole with a regular 15.3 ppg Class K cement + expanding agent (0.36% volumetric expansion)

Table 40 Cement Integrity Simulation Cases

Six separate cases were modelled (**Table 40**) considering different sizes of liner and reservoir hole size and cement slurries with and without the use of expanding agent. Note that the most likely configuration is a 5 ½” Liner in a 8 ½” open hole.

The simulation results indicated that for the cases without expanding agent in the cement (cases A, B, C) there is a risk of formation on an inner micro-annulus and disking failure in the liner lap. The micro-annulus forms as the well is shut in primarily due to the reduction in wellbore pressure (pumps off and density reducing as the CO2 warms). For the cases with expanding agent in the cement (cases D, E, F) there are no predicted cementing failures.

Examples of results from Case B and E (Considered the most likely configuration) are shown in Figure 39 and Figure 40. The key to the different failure mechanisms (for use with Figure 39 and Figure 40) is shown below in Figure 38.

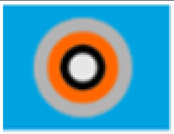
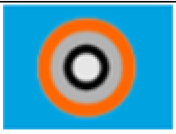
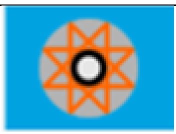
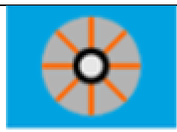
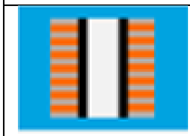
 Inner Microannulus Failure	 Outer Microannulus Failure
 Shear Failure	 Tensile Failure
 Disking Failure	

Figure 38 Key for Cement Failure Mechanisms

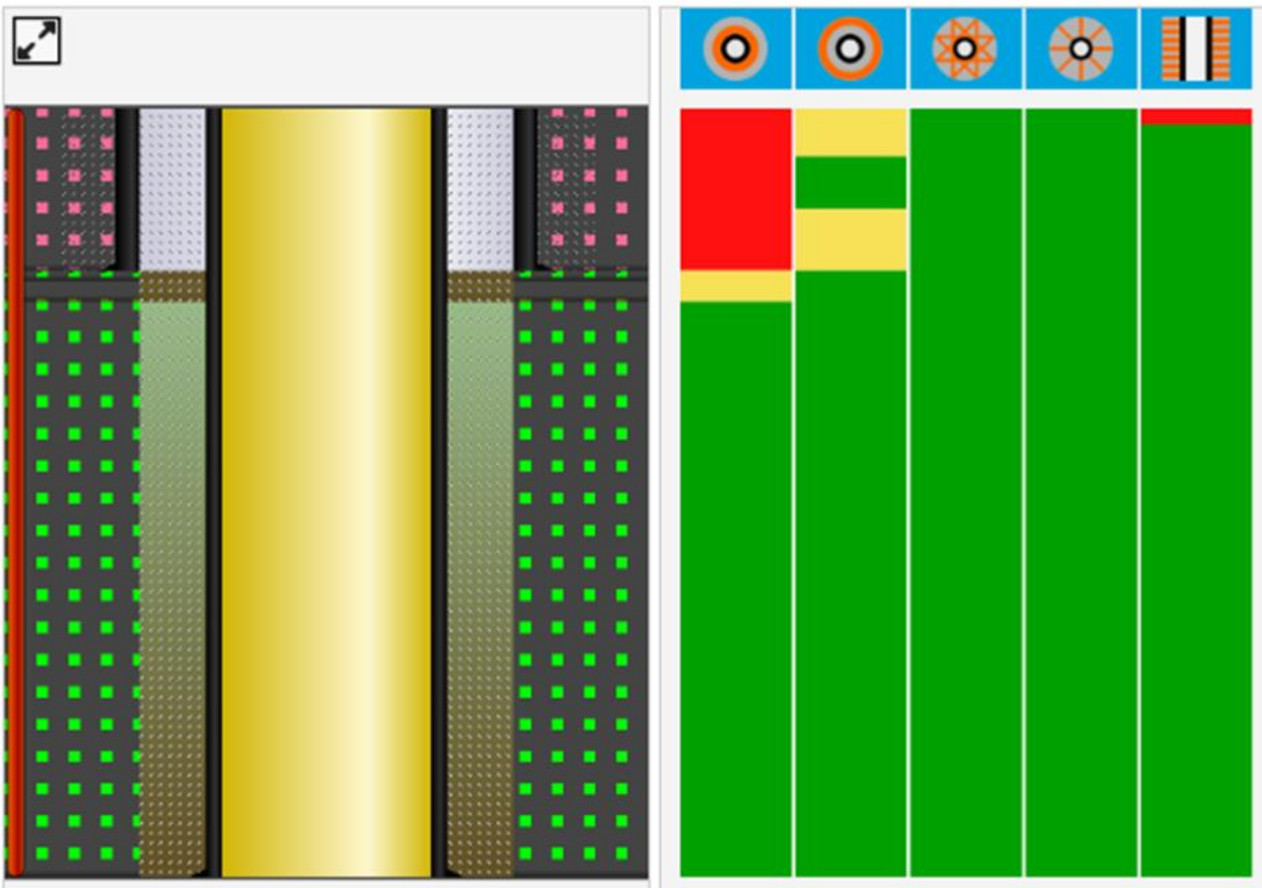


Figure 39 Case B: 5 ½" Liner in 8 ½" Open Hole with 15.3 ppg Cement

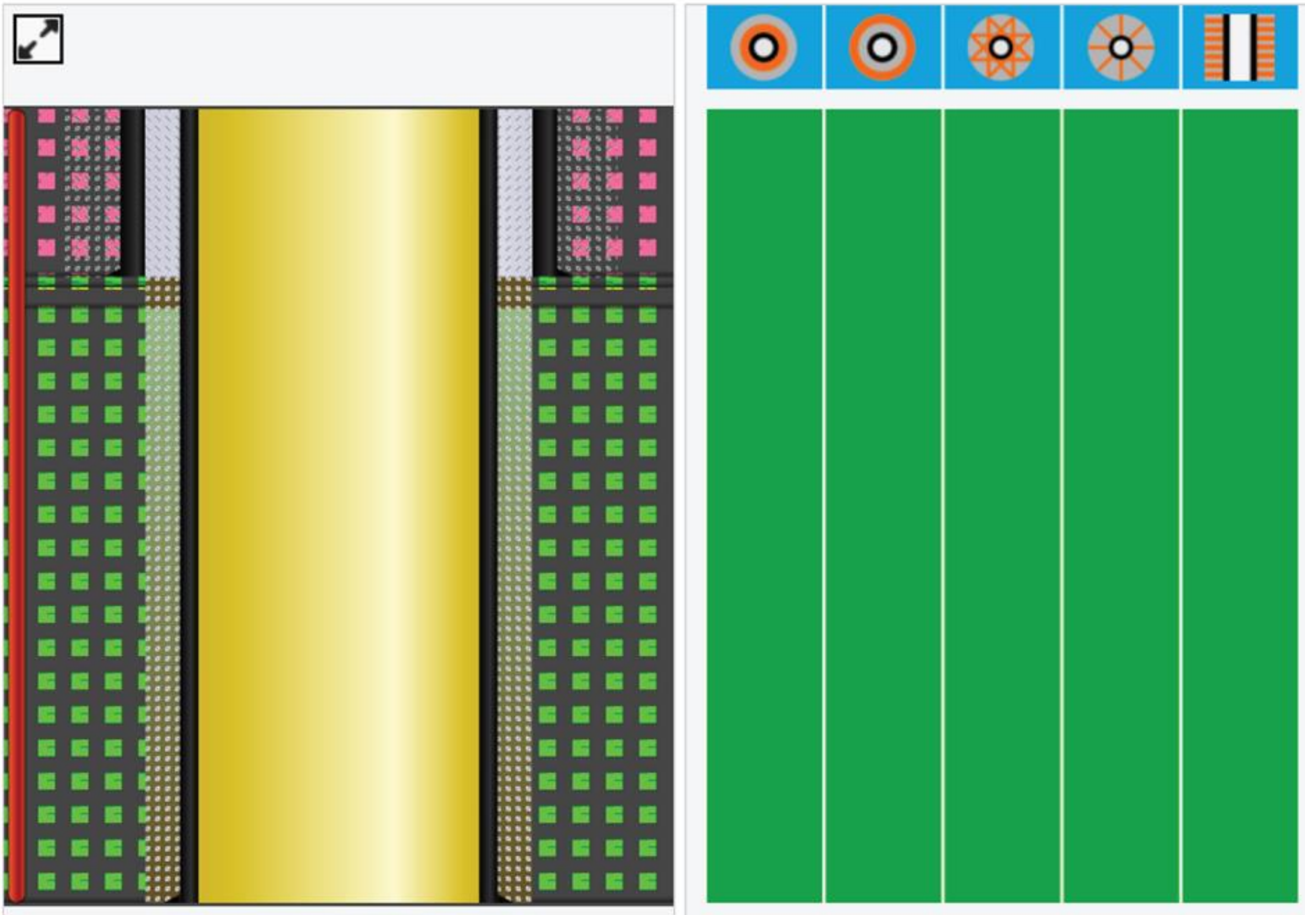


Figure 40 Case E: 5 ½" Liner in 8 1/2" Open Hole with 15.3 ppg Cement with Expanding Agent

The recommendation is to use expanding agent in the cement. Expanding agent works by putting the cement in compression during hydration with the expanding agent helping to counteract shrinkage.

As stress and fatigue modelling progresses, further workstreams may develop to reduce the magnitude of thermal cycles such as insulating packer fluids and / or insulated tubing.

5.11.7 Cement Fatigue

As the scope of the NZT / NEP project has expanded, the effect of power station dispatchability on well has reduced somewhat, as there will be more of a continuous base level of CO_2 injection available from ZCH and industrial sources on Teesside. However, the CO_2 injection wells will still be designed to take the dispatchable cycles of CO_2 from electricity generating plant for cases where either industrial capture has not started yet, or for trips and outages in industrial capture plants.

By reducing the rate into a well, or cycle the use of a single well, each well might be shut in once or twice per week as an upper limit. Spread over all five injectors, this would mean that over a 25-year project lifetime, an individual well might see anything up to 1000 cycles in total.

The analysis of the impact of well temperature and pressure cycling on cement integrity assume linear elastic behaviour of the cement but not the cumulative cycling or fatigue effects. Fatigue is usually defined as a premature failure of materials due to cyclic loading at a stress level lower than its strength under static load conditions. It is modelled by using a S-N curve which represents the ratio of cycling failure load versus static failure load versus the number of cycles. The S-N curve is modelled as a straight line on a logarithmic scale.

Well cycling is common in the oil and gas industry; Water-Alternate Gas injectors (WAG wells), rod-pumps ("Nodding Donkeys") and gas storage wells for seasonal fuel demand to name a few.

Failures in cement occur in first few cycles if they do at all – as is sometimes seen in a water injection well injecting cold water.

The key to integrity assurance is flawless cement job execution and the cement set in compression (expanding agent as described above) with a full suite of cement evaluation logs

It is worth noting that well integrity failure due to cycling generally occurs very early, after the first few cycles. The studied of well integrity of 6062 natural gas storage wells[6] show that 428 out of 6062 wells were leaking (7%). For the wells that leaked, leakage occurred within the first few cycles. 90 % of the leaking wells started to leak before cycle number 4.

This observation was confirmed during the BP Water Injection in Soft Sand large scale cement integrity study[7], where a cement annulus was cycled to 6,000 psi 134 times without measuring a change in the annulus permeability.

It is also worth noting that pressure and temperature cycles in NEP wells are relatively benign – e.g. BHP changes by <10bar (145 psi), well temperature only changes by 10 deg C over periods of days when shut-in and re-started.

Few studies have been performed with more than 1,000 cycles of fatigue. One study (Robert Pytlik et al. Fatigue of Rocks - NRMS-2017-020 ISRM - Conference Paper – 2017) suggests that the S-N curve for cement/sand mortar after 2,000 cycles is within 80% of the initial shear strength (see Figure 41). The spread of the data results is

[6] Journal of Petroleum Technology, Volume 41, Number 11, 1989, Cement Bonding Characteristics in Gas Wells, Roy S. Marlow
[7] Water Injection in Soft Sands (WISS) Cement Zonal Isolation Project Large Scale Testing, 11-June 2014

large and the reduction of the material strength due to repeated loading differs across the range, but occur soon after cycling begins as described above.

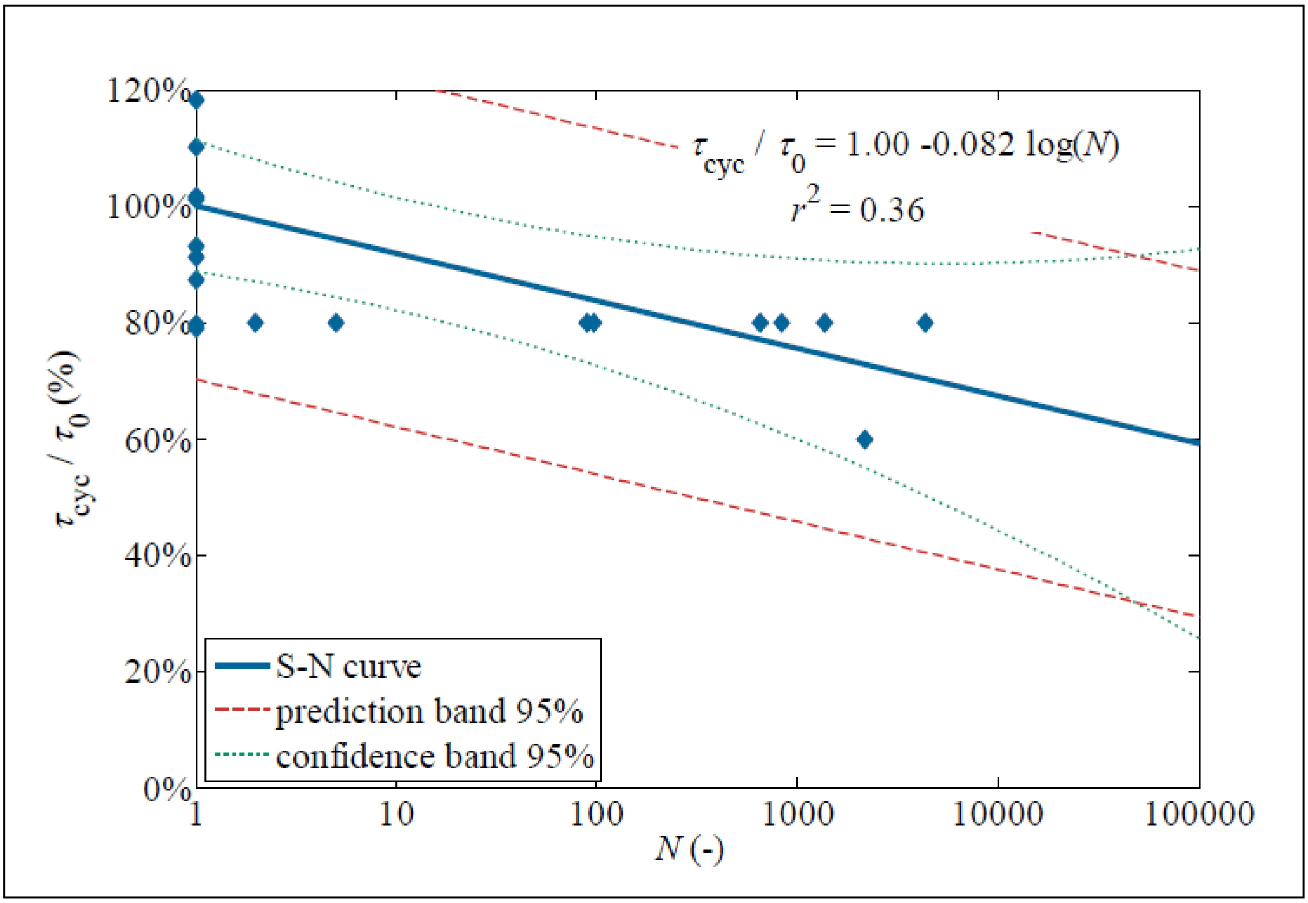


Figure 41 S-N Curve for Cement/Sand Mortar (Robert Pytlik et al. Fatigue of Rocks - NRMS-2017-020 ISRM - Conference Paper – 2017)

Thus, in order to consider possible fatigue of the cement sheath after 1,000 cycles, a 20% decrease of the measured cement compressive strength and tensile strength was used in the Cement Integrity Simulator. Using the most probable case of a 5 ½" liner in 8 ½" Open Hole with expanding agent- (Case E) with 20% downgraded cement properties, the simulation shows no failure (see Figure 42).

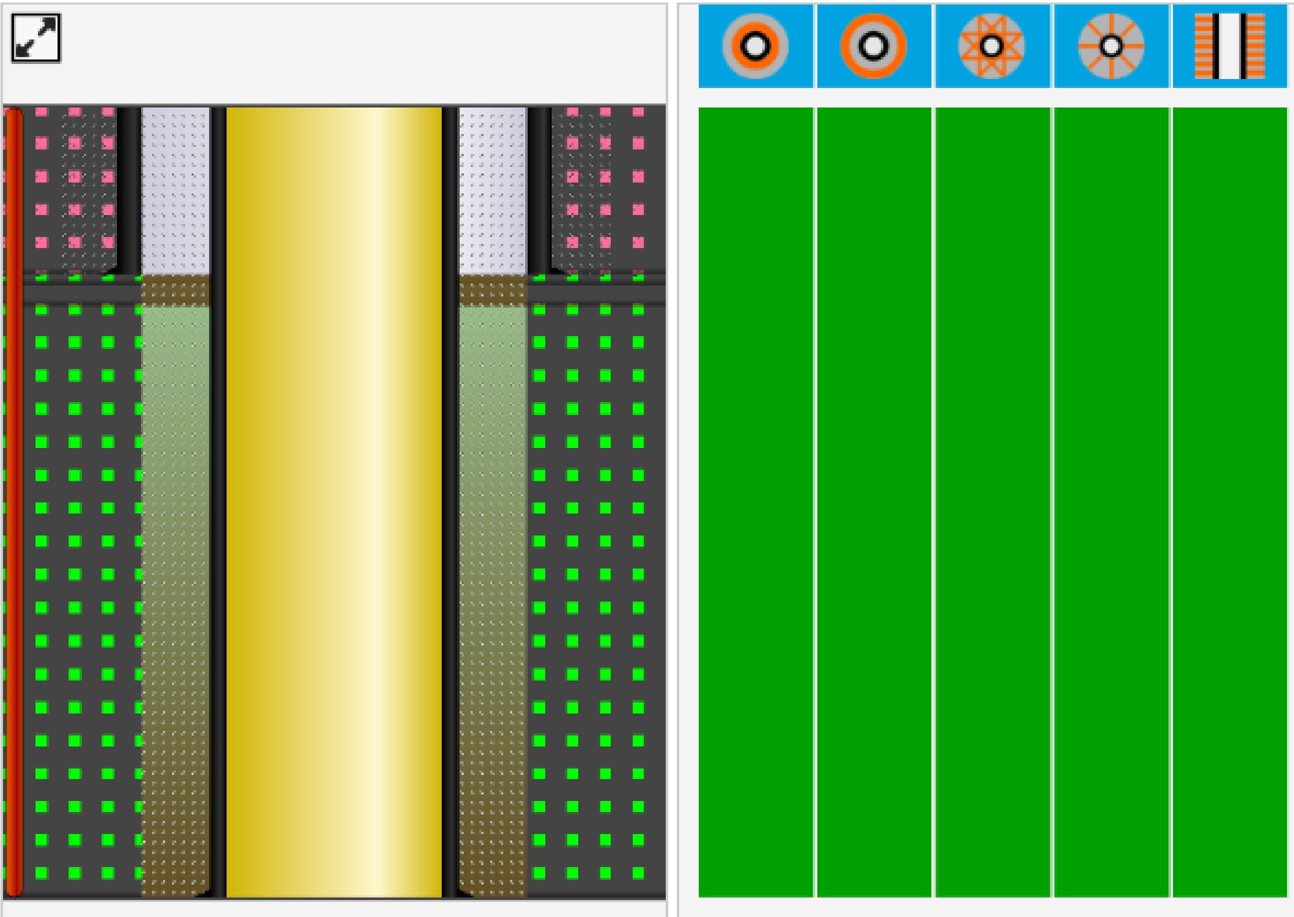


Figure 42 Case E : 5 ½" Liner in 8 ½" Open Hole with 15.3 ppg Cement with Expanding Agent, Cement Strength Down-Rated by 20%

5.11.8 Reservoir Dilation

[HOLD] Placeholder for conclusion on effects on cement of the reservoir uplift due to injection

5.12 Metocean Summary

A full technical report on metocean conditions for Net Zero Teesside has been produced. The key data from this report are tabulated below in

Table . It is important to recognise the uncertainty with these predictions resulting from the following:

- Bathymetry – due to small scale and transient seafloor dunes;
- Ocean currents – due to lack of site-specific measurements and short model dataset;
- Ocean temperatures – due to a lack of measurements and short model dataset

Parameter	Units	Value	Notes
Maximum Wind Speed	m/s	1yr: 22.0, 10yrs: 24.9, 25yrs: 25.6, 50yrs: 26.0, 100yrs: 26.3, 1000yrs: 27.3	1h wind speed at 10m above the surface, directions are coming from
Maximum Significant Wave Height	M	1yr: 5.8, 10yrs: 7.0, 25yrs: 7.6, 50yrs: 8.0, 100yrs: 8.5, 1000yrs: 10.9	1h wave height, directions are coming from
Maximum Surface Current	m/s	1yr: 1.94, 10yrs: 2.11, 25yrs: 2.16, 50yrs: 2.19, 100yrs: 2.22, 1000yrs: 2.34	Directions are towards; possible bias due to lack of on-site measurements
Maximum Near-bed Current	m/s	1yr: 1.38, 10yrs: 1.54, 25yrs: 1.58, 50yrs: 1.63, 100yrs: 1.67, 1000yrs: 1.82	Directions are towards; possible bias due to lack of on-site measurements
Maximum Air Surface temperature	°C	1yr: 18.4, 10yrs: 23.1, 25yrs: 23.4, 50yrs: 23.5, 100yrs: 23.6, 1000yrs: 23.8	
Minimum Air Surface temperature	°C	1yr: 3, 10yrs: -1.8, 25yrs: -2.5, 50yrs: -2.8, 100yrs: -3.1, 1000yrs: -4.0	
Water Depth	M	60	
Sea Surface Temperature	°C	1yr: 16.6, 10yrs: 16.7, 25yrs: 16.8, 50yrs: 16.8, 100yrs: 16.8, 1000yrs: 17.1	Large uncertainty in return values longer than 5 yrs due to short model timeseries
Mudline Temperature	°C	1yr: 16.6, 10yrs: 16.7, 25yrs: 16.8, 50yrs: 16.8, 100yrs: 16.8, 1000yrs: 17.9	Large uncertainty in return values longer than 5 yrs due to short model timeseries
Temperature Gradient Mudline to Sea Surface	°C	0.68	Annual average

Table 41 Metocean Conditions

6.0 Completion Design

6.1 Summary

CO_2 injector wells will be completed with a cased-and-perforated liner. Work done by the White Rose Project previously indicates a competent Bunter sandstone with no risk of sand production when shut-in. This is in alignment with fields in the surrounding area which are also cased and perforated. Furthermore, as the field is being pressurised rather than depleted, net pressure on the sand grains will decrease, reducing residual sand production risk.

Flow-wetted tubulars in the lower part of the well (liner, any casing overlap and the lower part of the tubing at least) will be 25% chrome super-duplex to mitigate CO_2 corrosion in the presence of reservoir brine.

Engineered equipment (packer, SSSV, nipple profiles, DHPTG mandrel etc.) will be a nickel alloy steel such as Inconel 725, Incoloy 825 or 925.

A dual downhole pressure temperature mandrel will be used to monitor pressure conventionally inside the tubing, but also in the ‘A’ annulus, as the annulus gauge on the xmas tree will not read correctly with the fall in annulus liquid level which will occur under cold temperature injection conditions.

An option to incorporate DAS fibre optic measurements will be carried through into the next stage the project which involves more detailed design and engineering (Define / FEED). The decision to proceed with this technology will depend on the final monitoring, measurement and verification plan (MMV) and further modelling on the impact of the completion design changes on well operation and management.

The tubing-casing ‘A’ annulus will be filled with either base oil or MEG to mitigate the risk of a conventional brine freezing under low temperature operation, and also formation of carbonic acid should CO_2 leak past the packer into the annular space.

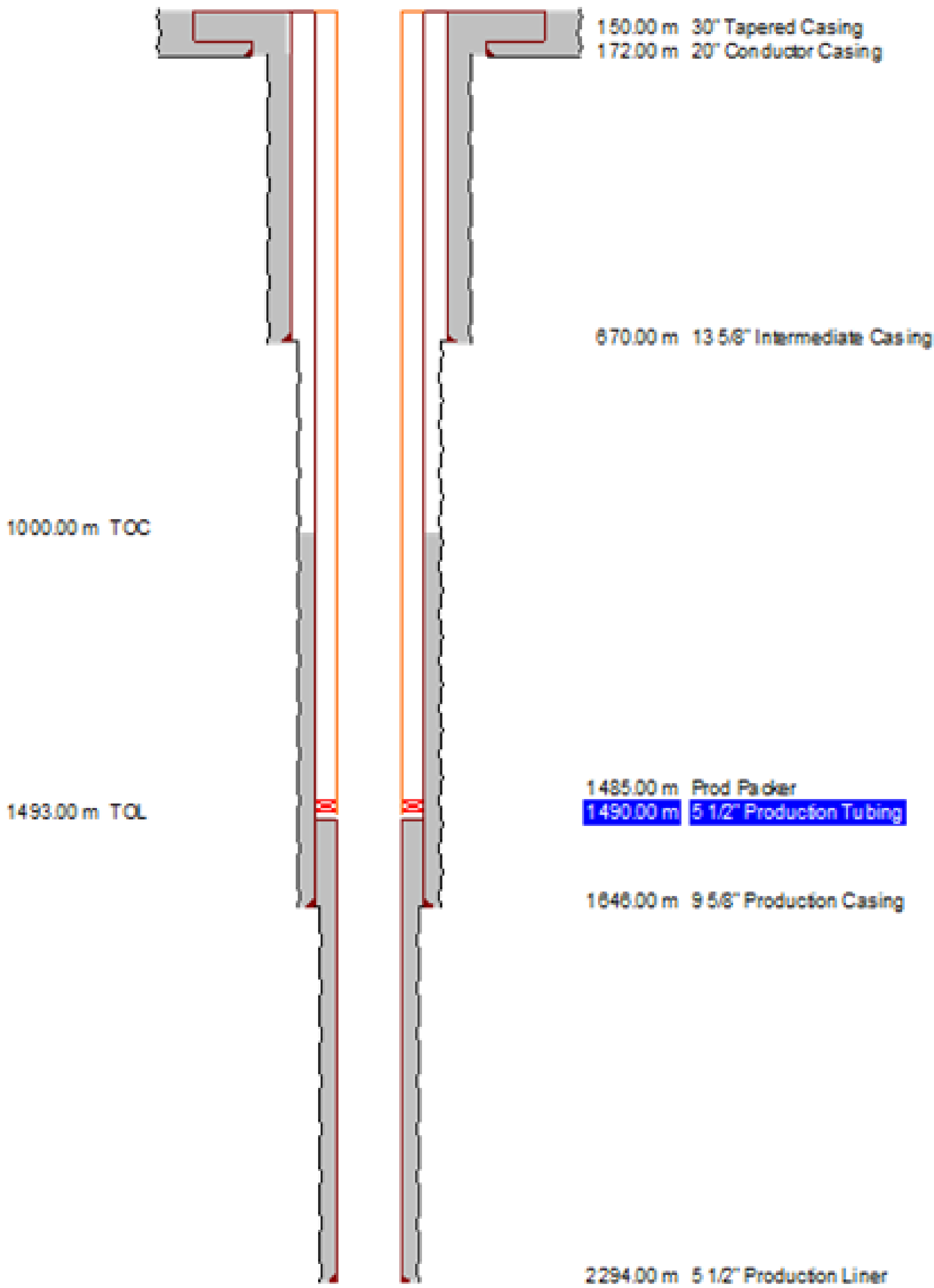


Figure 43 CO2 Injector Schematic (d

6.2 Brine Production Wells

Although brine production wells are likely to be needed in subsequent phases of the project when injected volumes of CO_2 increase, they are not needed for Phase 1 as there is sufficient pore volume and compressibility to prevent the reservoir pressure increasing beyond cap rock limits with the planned stored CO_2 volume.

Therefore, the design of brine production wells is not considered in the document.

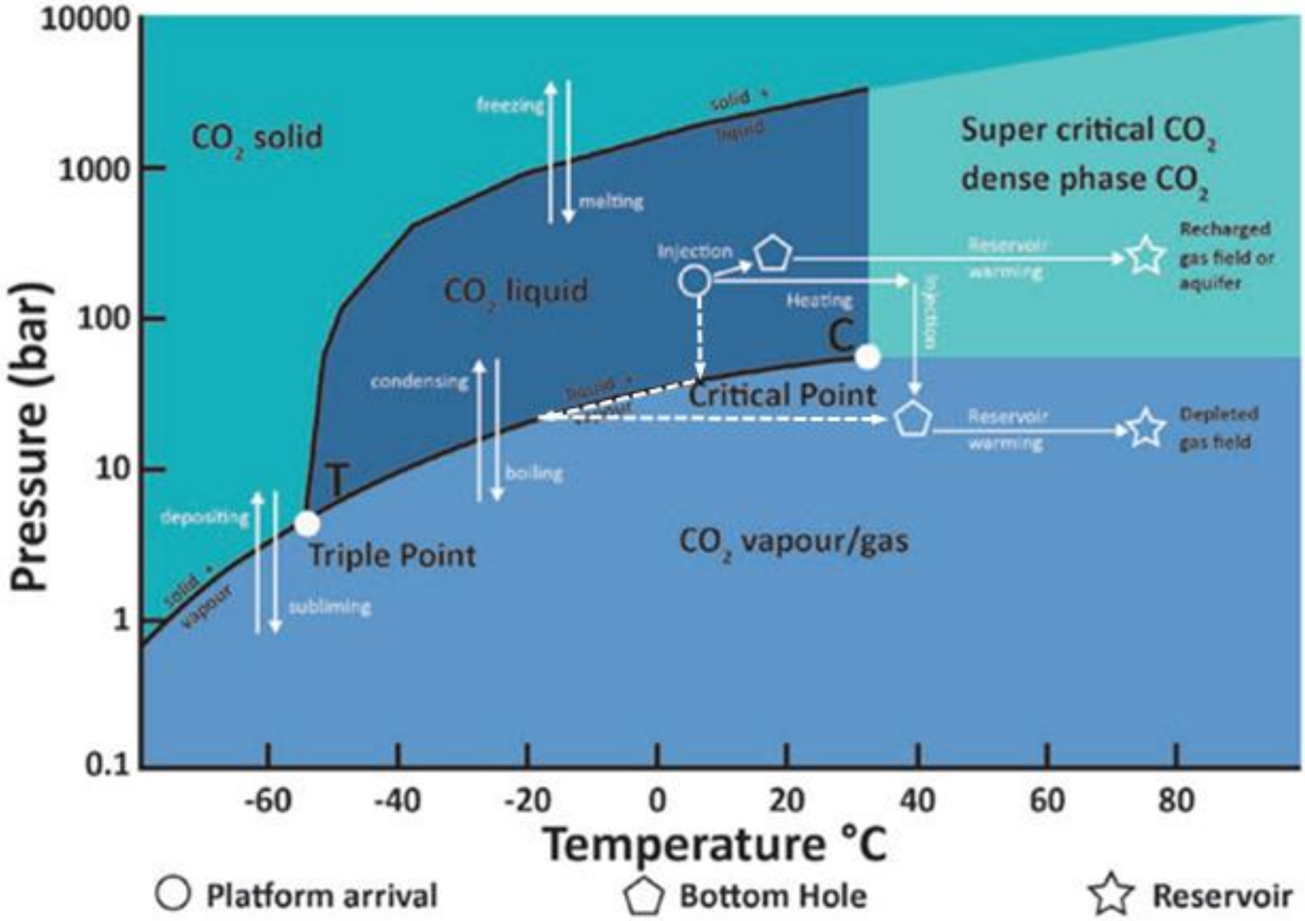
6.3 Flow Assurance

6.3.1 Phase Behaviour of Pure Carbon Dioxide

The properties of CO_2 are exploited in many industries; as a dissolved gas in fizzy drinks, as a stored liquid in fire extinguishers and as a refrigerant, as a solid for sublimation for special smoke effects in films and theatres and as a super-critical fluid (dense phase) as a solvent. Dense phase is often favourable for transportation or for flow in the reservoir for a CCUS project due to low viscosity, but for wells, the Joule-Thompson cooling effect is the most important and is generally not a benefit.

Referring to **Figure 44**, the path through phase diagram shows two options for injecting into a pressurised field (e.g. Endurance) or a depleted field (e.g. Hewett). CO_2 arrives at the offshore wellhead as a liquid, in this case at around 110 bar (~1595 psi) and at ~4 deg C seabed temperature (white circle).

The upper white pentagon shows the pressure and temperature increase slightly as the CO_2 is injected as a liquid down the well into a pressurised reservoir (i.e. one that is at higher pressure than the CO_2 arrives at). The CO_2 is then heated to geothermal equilibrium as the plume migrates through the reservoir, eventually becoming a super-critical fluid once the temperature rises above 31.1 deg C. This path is typical of injection into a saline aquifer, and reflects what will happen on Endurance for NZT/NEP. There are no large pressure drops along the path, and so temperatures are manageable during normal operation, although start-up may require some special measures if the SIWHP is lower than ~50 bar, for example with a gas cap in the tubing in early life for Endurance before the reservoir has pressurised sufficiently to maintain the tubing as a liquid or dense phase fluid.



Critical point 73.9 bara (1017 psia), 31.1 deg C

Figure 44 CO2 Phase Diagram

The lower white pentagon shows the reservoir pressure in a depleted field, with two paths to get to it; the solid arrows with additional heat, and the dashed arrows naturally with no additional heat to mitigate J-T cooling.

Taking the unheated path, the CO2 starts to boil off across the wellhead choke from arrival pressure to ~11 bar (160 psi), typical of a depleted gas field. The fluid follows the vapour line (in the theoretical case of no additional heat input) as the fluid is injected down the tubing, arriving at the reservoir as a cold gas, where it migrates through the reservoir and heats up to geothermal equilibrium. In reality, heat from the surrounding overburden will reduce the temperature drop, but it will still reach a minimum of well below zero deg C.

The heated path shows what is required to mitigate the J-T cooling; the liquid CO2 is heated on arrival (to ~80 deg C as an example for the Hewett field as considered for NZT/NEP), which allows the depressurization to reservoir pressure to occur without the temperature dropping below zero. The heating requires large amounts of power and is the primary reason why depleted gas fields have not been used for CO2 storage to date (other than for experimental / pilot projects).

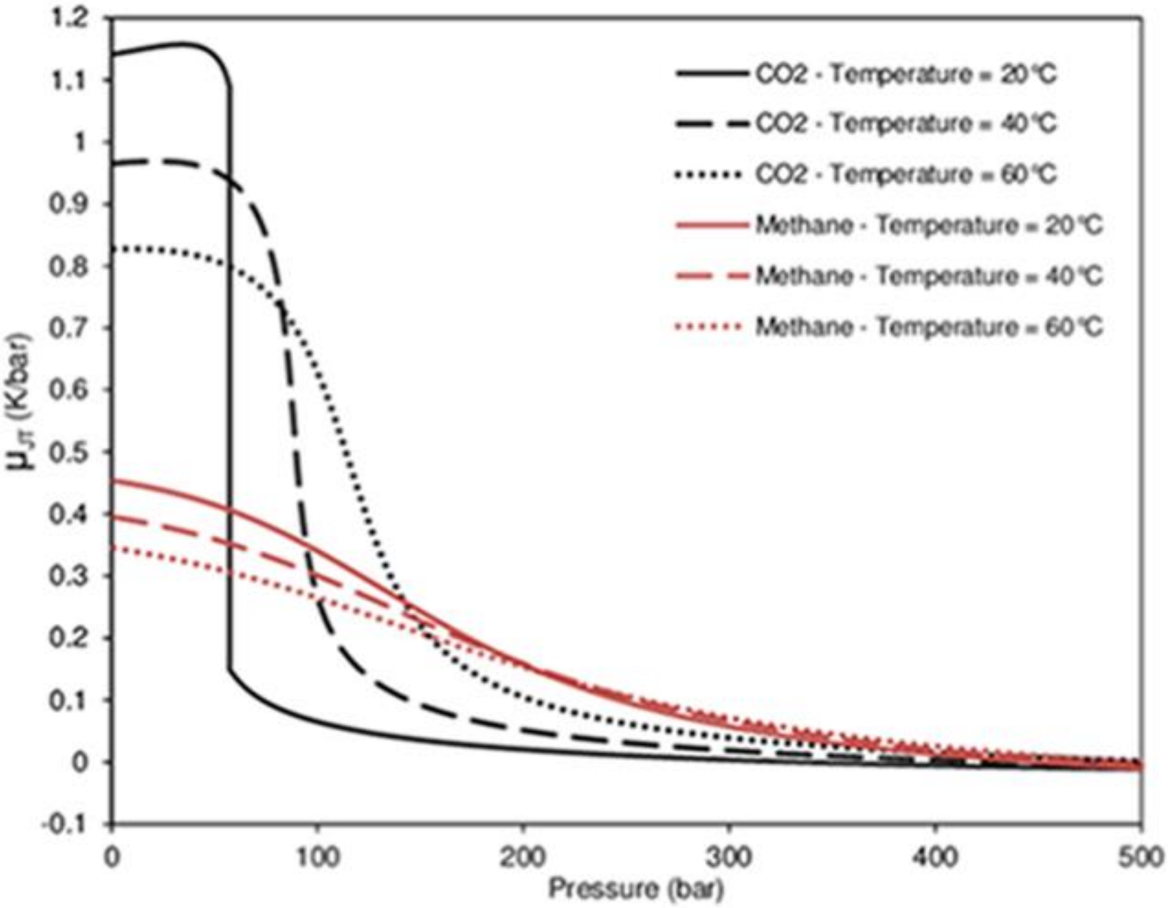


Figure 45 CO2 Joule-Thomson Curve

For an alternative view, **Figure 45** shows the J-T coefficient for CO2 at representative temperatures, with methane included for comparison. They key point to note is that as the ambient temperature falls, the J-T coefficient increases, but there is a sharp increase for CO2 as the pressure falls below ~150bar (for the temperatures plotted). Of particular interest is the 20 deg C curve for CO2 below ~50 bar which is more representative of Endurance – it can be seen that below this pressure, the temperature falls by more than 1 deg C for every 1 bar drop in pressure, which explains the issues arising when CO2 flashes off across a choke into a low pressure sink at the top of the tubing or in a depleted reservoir.

For a saline aquifer or other pressurised reservoir, a challenge remains for some events, for example:

- Bleeding off above the SSSV for regular testing will take days rather than hours depending on the low-side pressure – if possible, design the test that does not cross the phase transition line.

- A leak in the tree above a closed SSSV or LOPC at the tree or wellhead can result in very low temperatures as the pressure is released to local ambient – if no additional heat input is assumed, the temperature will follow the vapour line down to -78.5 deg C at 1 atmosphere which is outside of any downhole equipment operating envelope. Pressure provided by a head of water in a subsea well helps, but in the case of shallow water typical of the southern North Sea and NZT/NEP, this only increases the minimum temperature to ~-55 deg C which still requires specially qualified equipment and design cases.

6.3.2 Phase Behaviour of Impure Carbon Dioxide Systems

For impure CO2 systems such as NZT/NEP, even with >95% CO2, the gas-liquid Phase transition line becomes a thin envelope and the critical pressure increases as shown in Figure 46

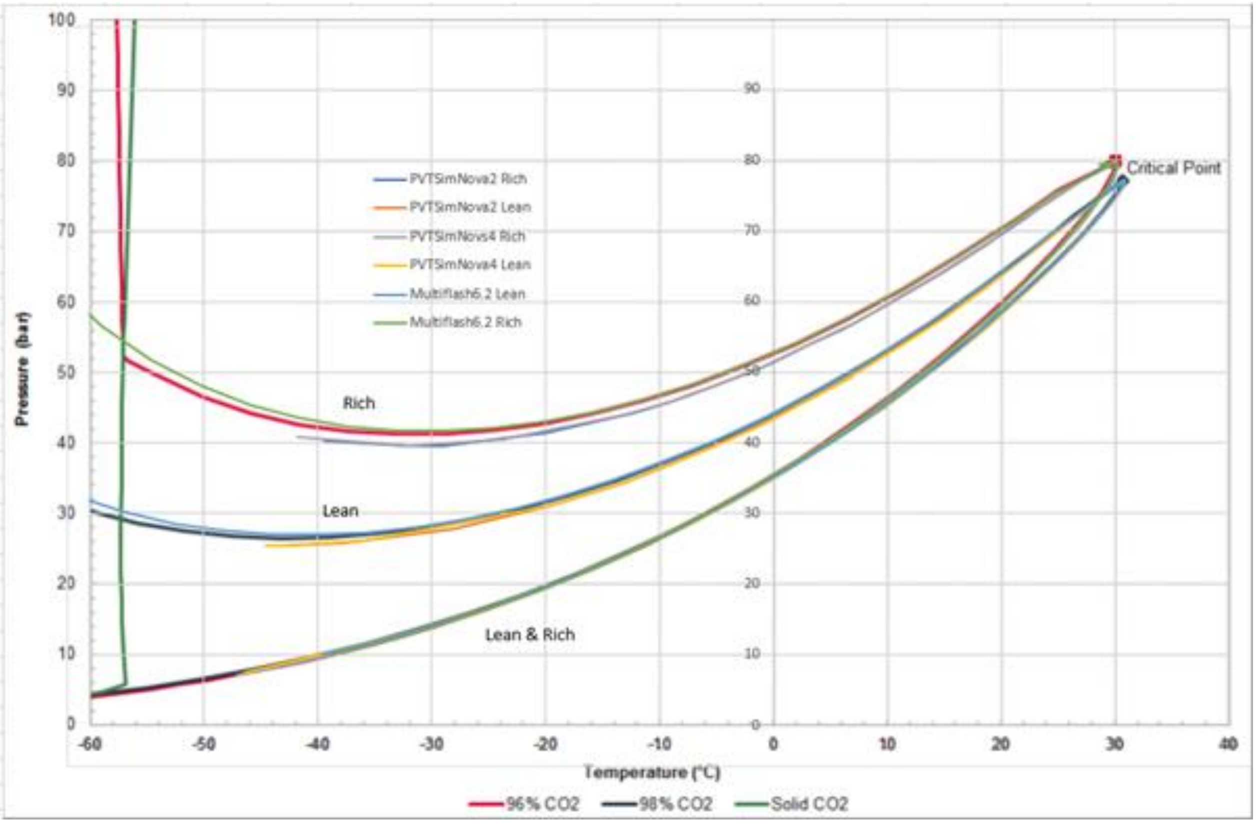


Figure 46 NZT/NEP Specification Phase Envelope for CO2 Containing Impurities

6.3.3 Requirement for Water Washing

The native fluid in Endurance is a highly saline brine(~156,000ppm NaCl measured, but potentially up to 250,000 ppm). There are no hydrocarbons present – movable or residual.

When CO2 contacts a brine, the solution dehydrates and salt can be precipitated, and this is predicted to occur in Endurance, particularly in the case of a low injection rate that does not sweep the interface far enough into the reservoir fast enough. This is illustrated in Figure 47, showing the injectivity index as a function of cumulative injection for high and low-rate cases (1 MTPA ~ 52 mmscf/d at STP).

In the high rate case close to nominal well capacity, distributed precipitation occurs and there is negligible effect on well performance and the injectivity index remains constant. In the low-rate case, the injectivity drops significantly soon after injection begins and it is entirely lost after a throughput of 1 b

scf (~18 MTPA).

A progressive transition between these two regimes occurs at an injection rate of ~30 mmscf/d (0.6 MTPA).

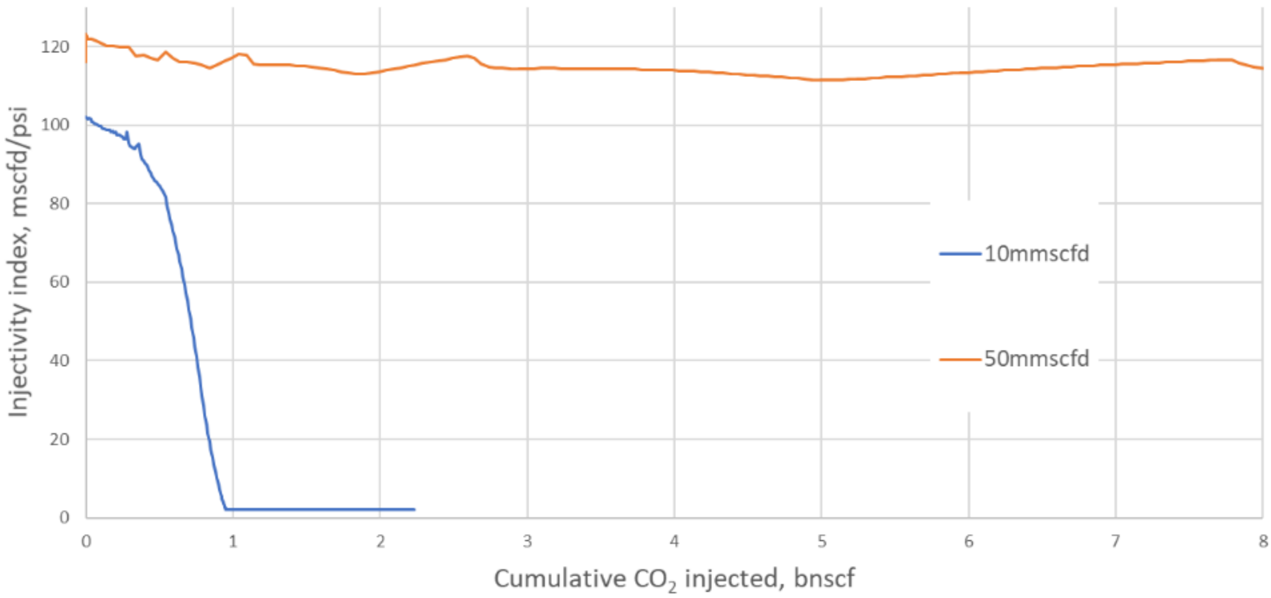


Figure 47 Injectivity Index for Low and High Injection Rates

As an analogue, this has been seen in another analogue other CCUS project, where halite has been observed in downhole camera surveys – the salt tends to precipitate out of perforations in low permeability streaks where CO2 has not flushed the brine far enough away from the well.

In general, the effects of this will be minimised by injecting up to 6000 bbl of fresh water at the time of completion (similar to a scale squeeze, sometimes known as a "shock treatment" in CCUS parlance) which would dilute the brine and eliminate the potential for halite drop-out in the near wellbore. Precipitation further out has ever-reducing effects as the area increases.

Furthermore, in early life, project may require "baseload" power generation which will generate a continuous injection rate for the first few years of operation before switching over to "dispatchable" operation where the whole system is modulated by electricity demand in tandem with renewables generation; this means that the CO2 – brine interface will move far out into the reservoir and will reduce the likelihood of injectivity impairment even further. Long term shut-ins are not expected to result in significant back-flow of brine back into the near wellbore.

That said, a practical wash water injection plan has been designed to allow regular washing of the well with fresh water (and MEG to prevent hydrates) to dissolve any salt that may reduce injectivity. The plan comprises two parts – a scale threat assessment based on water compatibility, and a pumping schedule based on well angle and tubing lift performance.

The wash water system needs to be capable of injecting water at 40 m3/hr against a maximum wellhead pressure of 110 barg (including a margin of +8.5 bar over SIWHP).

Wash water will be de-aerated sea-water (possibly with further oxygen scavenger) with biocide, corrosion inhibitor and possibly a scale inhibitor.

Following washing operations, the tubing is water-filled and the wellhead pressure will collapse to vacuum (water vapour pressure) in early life with. As a result, the wash water system must be robust against low pressure delivery and a method of addressing cold temperatures expected during re-introduction of CO2 designed; this may involve a nitrogen cushion or material qualification to cope with the transient sub-zero temperatures expected (though of short duration in the order of minutes maximum).

6.3.4 Halite Scale Threat Assessment

The scale threat assessment study concluded and recommended the following:

Adopt fresh water or an appropriately designed KCl brine to wash the near well bore of the Endurance injector well prior to dense phase CO2 injection. Selecting fresh water or KCl brine eliminates the potential for scale deposition on mixing with the hyper saline Endurance formation water.

- Do not adopt seawater to wash the near well bore of the Endurance injector well prior to dense phase CO2 injection. Seawater injection is not recommended as it was predicted to lead to significant calcium sulphate and potentially strontium sulphate scale deposition which could impact on injector skin values.

- Downhole wash water and scale inhibitor injection capability is not required to manage the production of Endurance formation water when brine production wells are required in later phases of the project. Predictions highlight that halite is not a threat and whilst some mineral species were predicted to be oversaturated (calcium carbonate, barium sulphate and calcium sulphate) the potential for these scales to deposit was considered very low and a preventative barrier (wash water or scale inhibitor injection) is not considered necessary.
- Be aware that injecting MEG90 into the near well bore and mixing it with Endurance formation water will lead to the oversaturation of some scale species and thus the potential for some deposition. This is limited by the volume of MEG90 injected.
- Ensure that an evaluation is undertaken to assess whether fresh water injection could lead to formation damage and, if it does, consider KCl brines at an appropriate strength.
- For future brine production wells (not considered in the BoD), producing Endurance formation water to surface to maintain reservoir pressure within safe limits does not create scaling conditions that require a preventative barrier. Halite was not predicted.

6.3.5 Hydrates

Hydrates can be formed between CO2 and water in a similar manner to methane hydrates.

Hydrate prevention strategies are not required for normal, shutdown, and restart operations because under normal circumstances with on-spec fluid (rich and lean), the operating conditions do not fall to -25°C or below 20 bara and so hydrates are not stable (Figure 48).

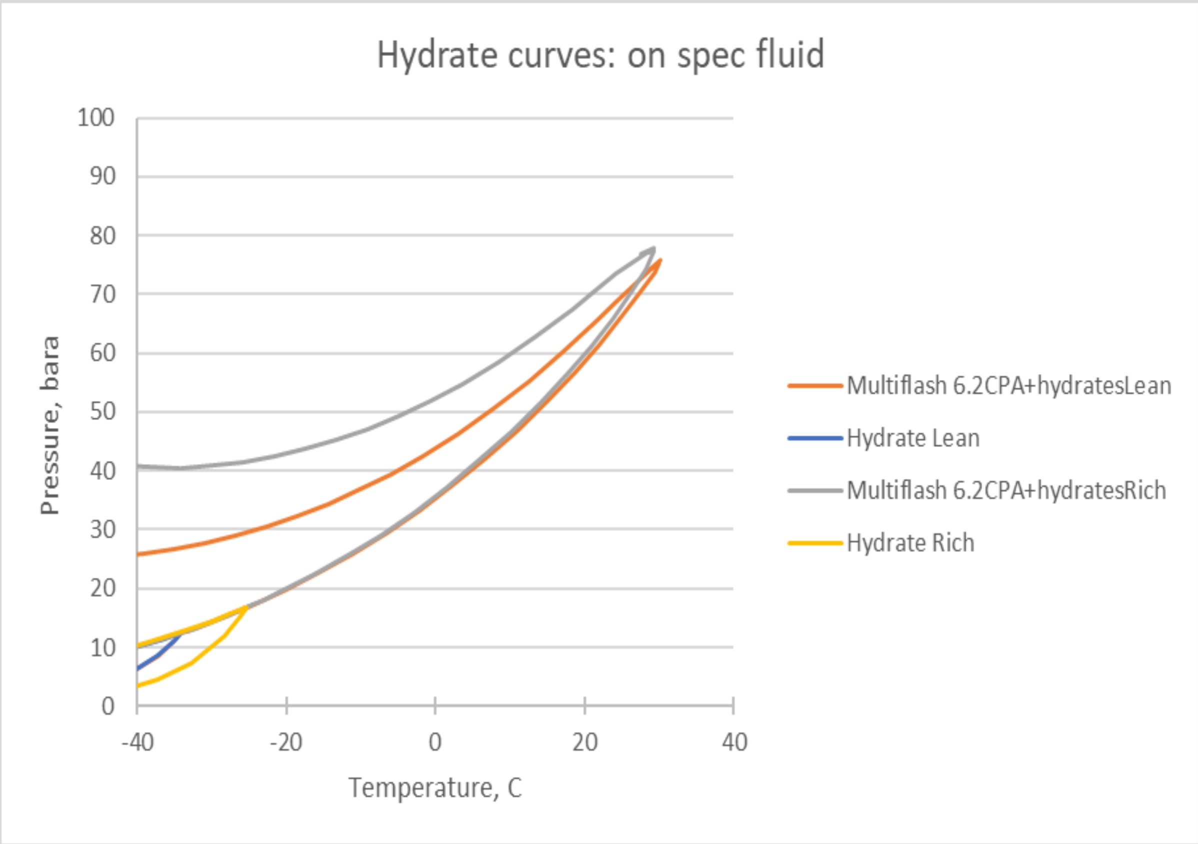


Figure 48 Phase Envelopes and Hydrate Curves in Contact with Pure Water

Hydrate prevention strategy is only required at the start and end of the water washing operation.

To achieve hydrate suppression at 200 bar and 4 deg C (representative of maximum pressure expected and minimum temperature expected for pure water in contact with CO_2 in the wellbore or near wellbore region of the reservoir), then 25 wt% MEG is required (Figure 49 and Figure 50).

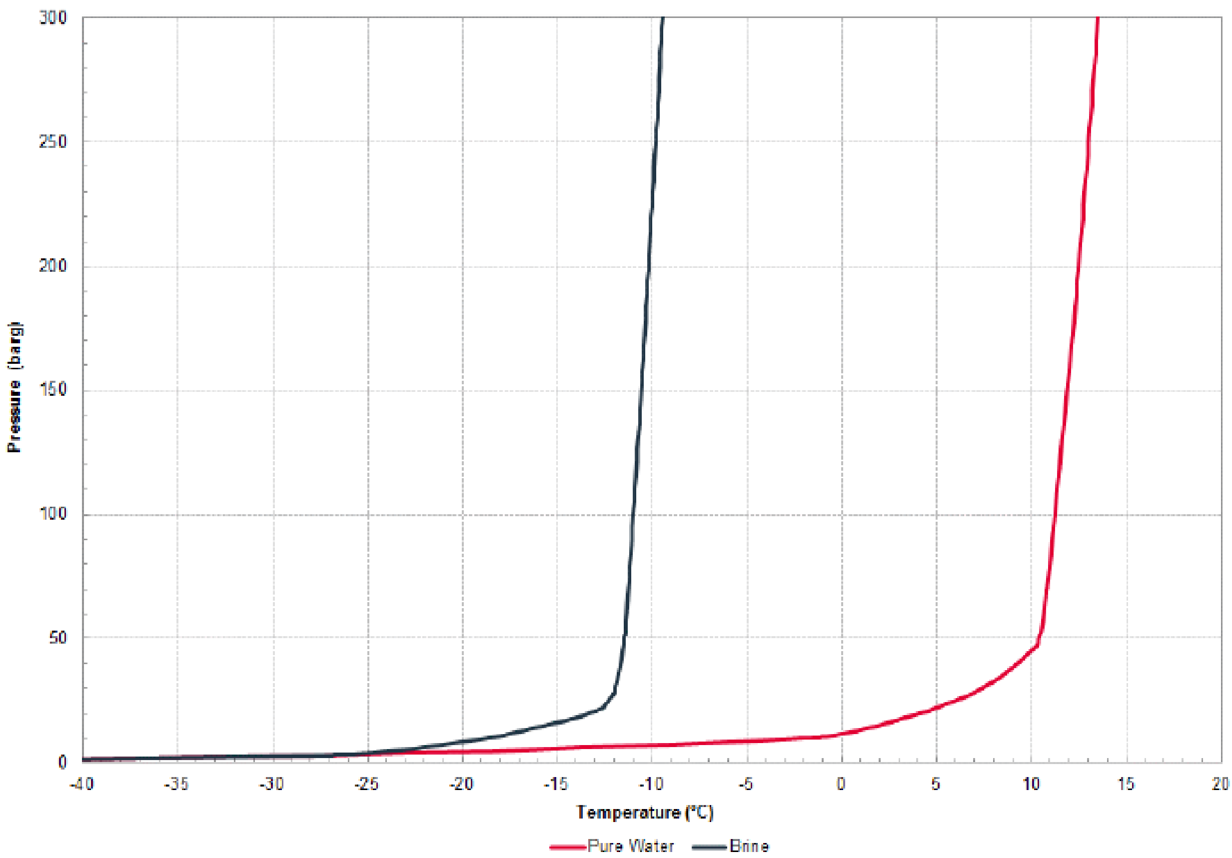


Figure 49 Hydrate Curve for CO2 in Contact with Water or Formation Brine

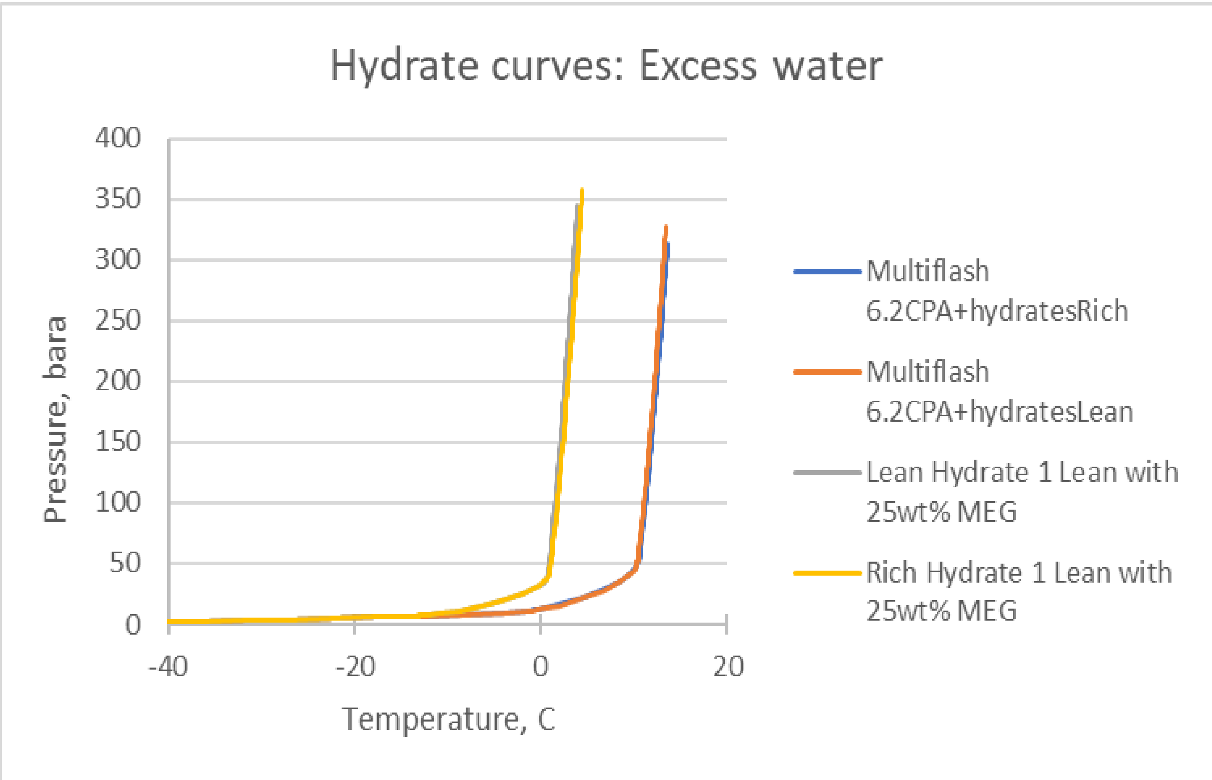


Figure 50 Hydrate Curves for Rich and Lean CO2 with Excess Water, with and without MEG

6.3.6 Hydrate Management for Water Washing

An early view of the MEG requirements during the water washing operation expects:

> 7.5 m3 of MEG is used to inhibit hydrates ahead of water washing and a further 2.5 m3 is used in the first 20 minutes of flowing the 40 m3/hr wash water schedule.
> 7.5 m3 of MEG is also used to inhibit hydrates after water washing, and a further 2.5 m3 is used during the first 20 minutes of resuming CO2 injection (at 1 MPTA) to prevent hydrate formation with any slugs of water hold-up.

Each well wash operation requires up to 20 m3 of MEG. For comparison, the tubing volume is ~29 m3.

6.4 Injection Pressure and Temperature Evolution over Field Life

Most of the flow-assurance work to-date has been done for a dry tree installation. This means that the water wash restart is too pessimistic and predicts a lower temperature on restart than will occur for a subsea well due to the SIWHP being positive at the mudline. This will be re-visited in Define.

6.4.1 Flowing Wellhead Pressure

Figure 51 shows the flowing wellhead pressure (downstream of the production choke) for a range of injection flowrates and reservoir pressures. At the start of operations, reservoir pressure will be ~140 bar, rising to ~200 bar as the store fills over its operating lifetime.

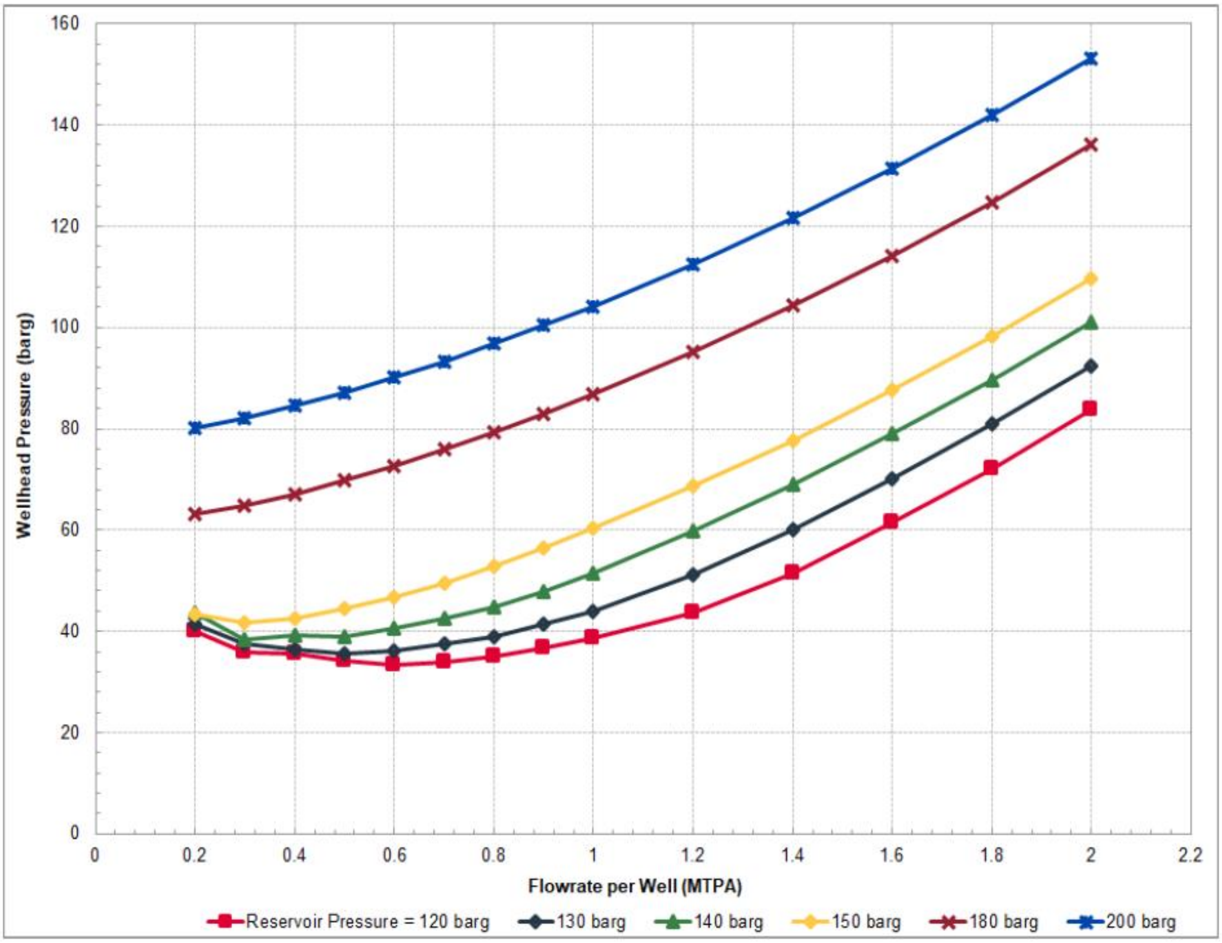


Figure 51 Steady State Flowing Wellhead Pressures vs. Flowrate and Reservoir Pressure

6.4.2 Flowing Wellhead Temperature

Figure 52 shows flowing wellhead temperatures (downstream of the production choke) for a range of flowrates and reservoir pressures.

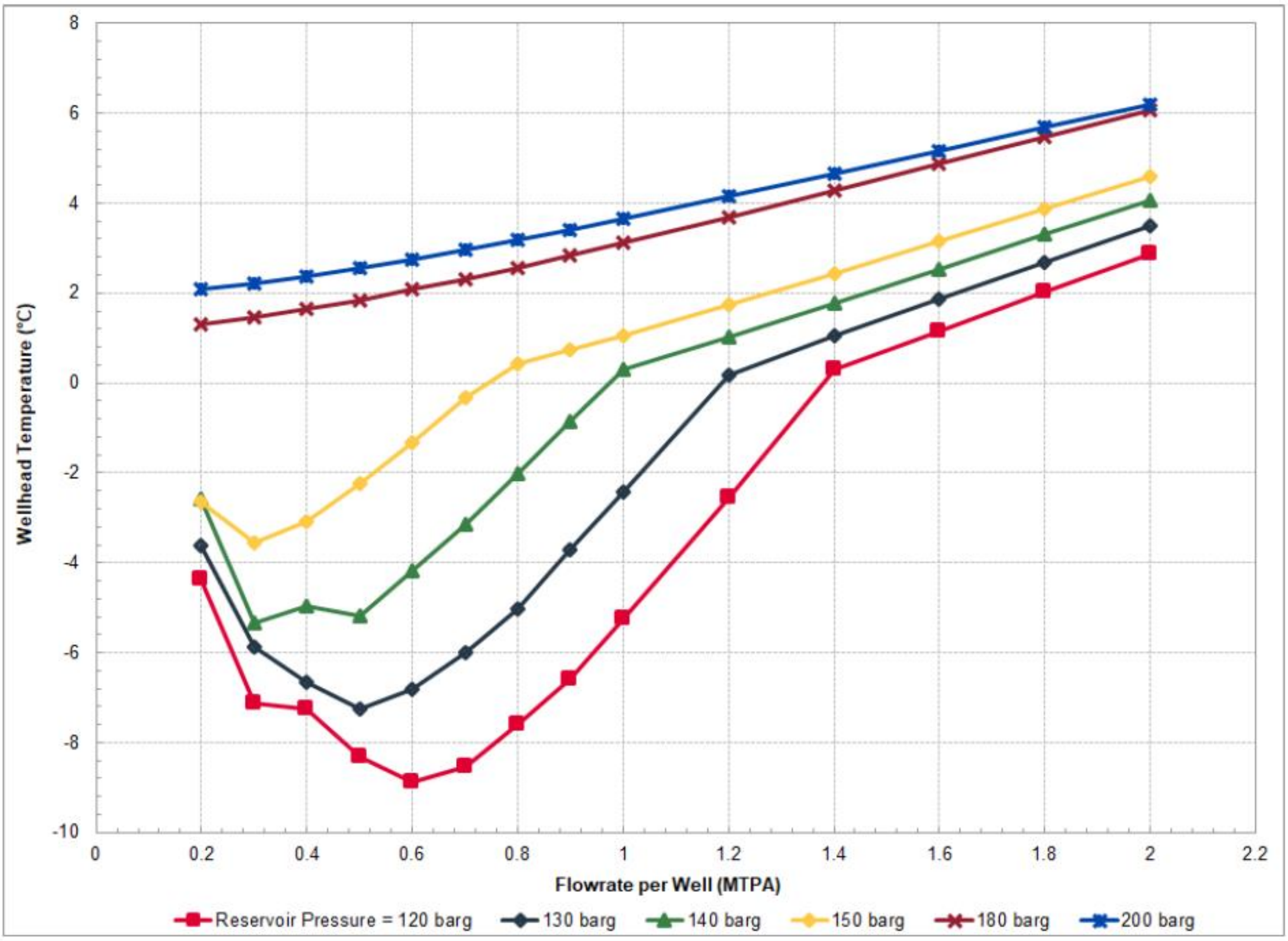


Figure 52 Steady State Flowing Wellhead Temperature vs. Flowrate and Reservoir Pressure

Key points to note from this plot are:

- At the start of operations (early life), reservoir pressure is ~140 bar, and wellhead temperature is not expected to fall below -6 deg C under normal operating conditions even at low injection rates, which is unlikely to present significant issues with standard equipment specification, although some equipment may need minor re-qualification or a design review depending on the supplier chosen.
- For injection rates at the well's nominal capacity of ~1 MTPA, FWHT will never fall below zero deg C.

The temperature expected downstream of the wellhead choke can be generalised versus wellhead pressure as shown **Figure 53**.

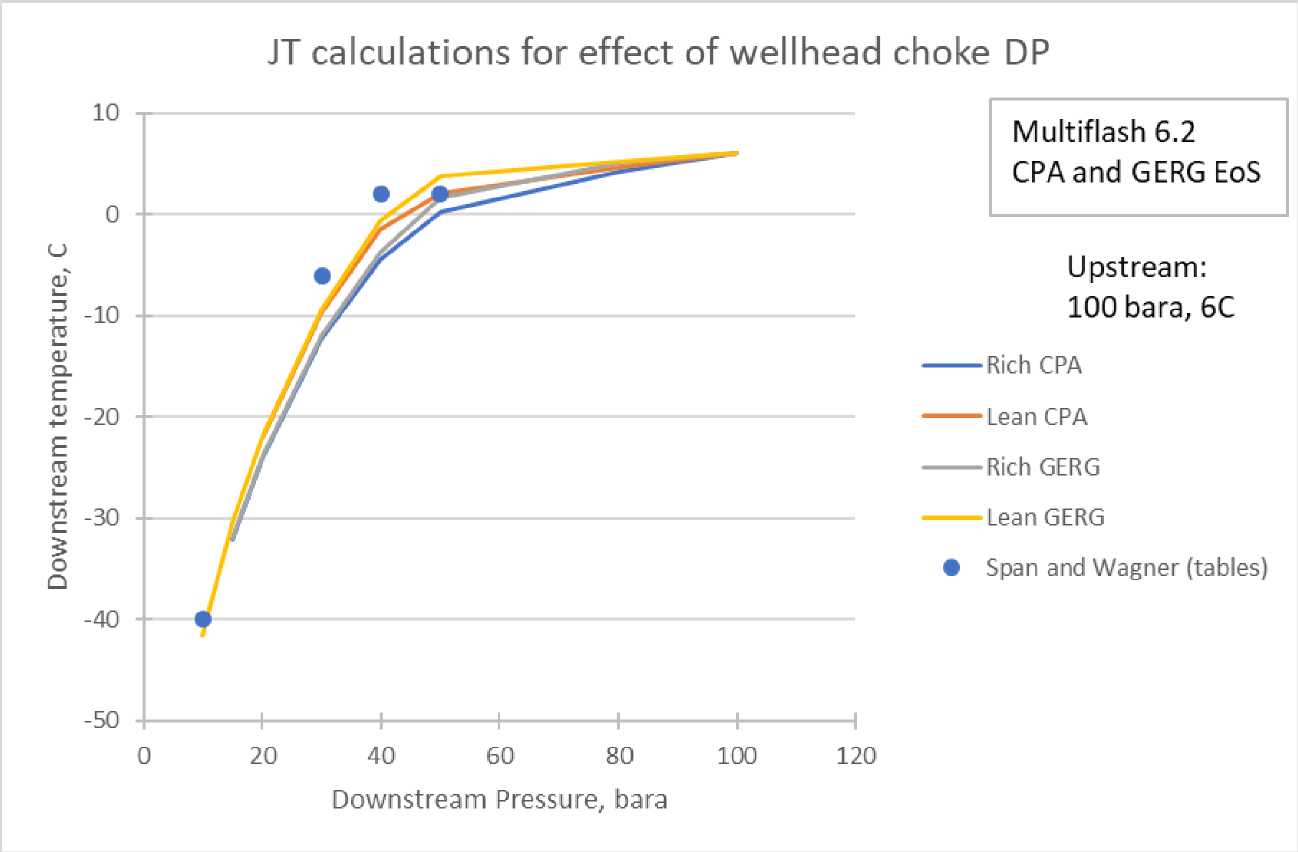


Figure 53 Flowing Wellhead Temperature vs. Pressure (100 bara and 6 deg C Arrival)

6.4.3 Restart after Water Washing

After water-wash operations in early life, the pressure at the top of the tubing will be low (in the order of a few bar). Under these conditions, introducing CO2 from the pipeline would result in a pressure drop through the liquid-gas transition line and a significant degree of JT cooling. This is illustrated in Figure 54. Genesis' OLGA modelling indicates that the tubing wall temperature is considerably warmer (minimum at -15°C), but this requires further verification as otherwise it may require additional equipment qualification or other methods of reducing the delta-P at restart such as bull-heading nitrogen prior to restart of CO2 injection or even pre-heating the CO2 at the wellhead.

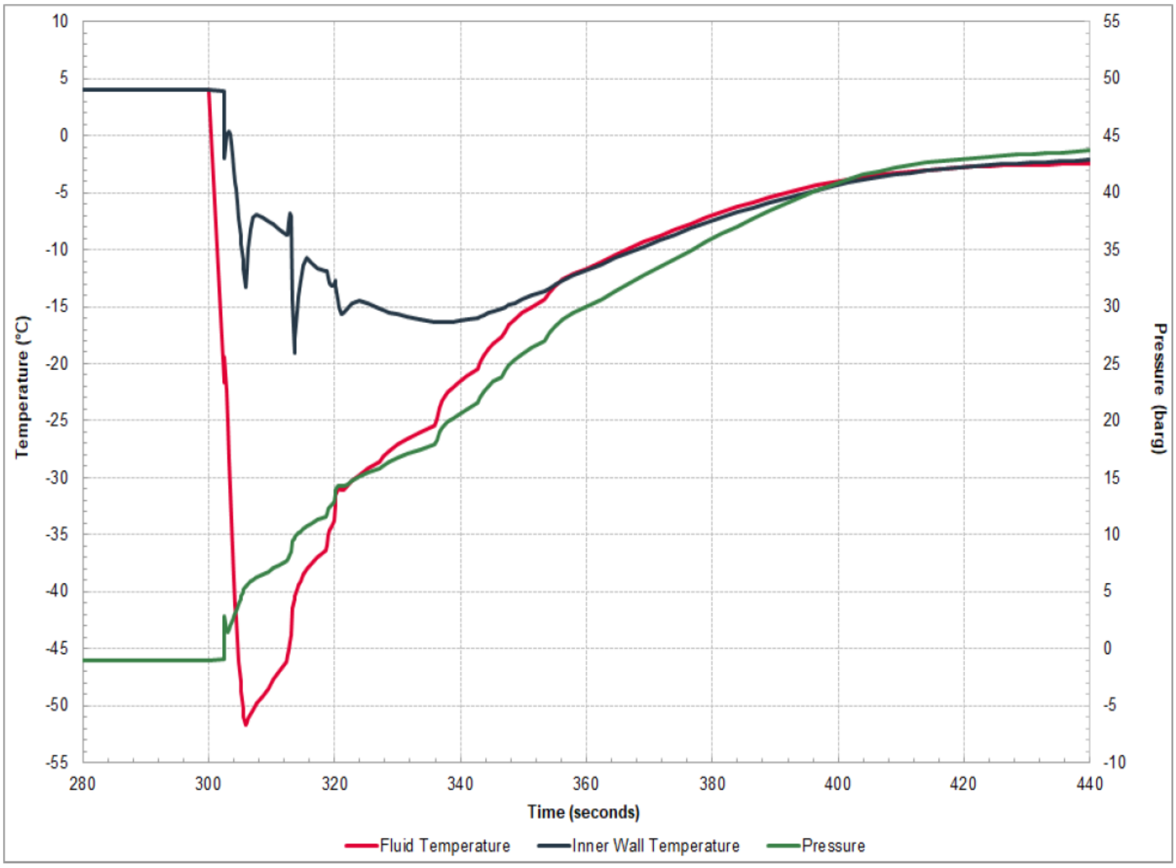


Figure 54 Wellhead Pressure and Temperature during Restart after Wash-Water Treatment

6.4.4 Occurrence of Multiphase Flow

During early field life when the reservoir pressure is less than 170 bara (initially 140 bara), CO2 is expected to evolve gas at the top of the tubing during shut-in periods.

At low flowrates, this will form a pocket which extends over the first section of the tubing. Below this point the pressure will be sufficient to drive the CO2 back into dense phase. At high flowrates and at higher reservoir pressures, the tubing is in dense phase throughout.

At the initial expected reservoir pressure of 140 barg, a gas pocket is expected for flowrates less than 1 MTPA (which is the intended nominal maximum injection rate per well). When the pressure exceeds 170 barg dense phase conditions are expected regardless of flowrate, as illustrated in **Figure 55**.

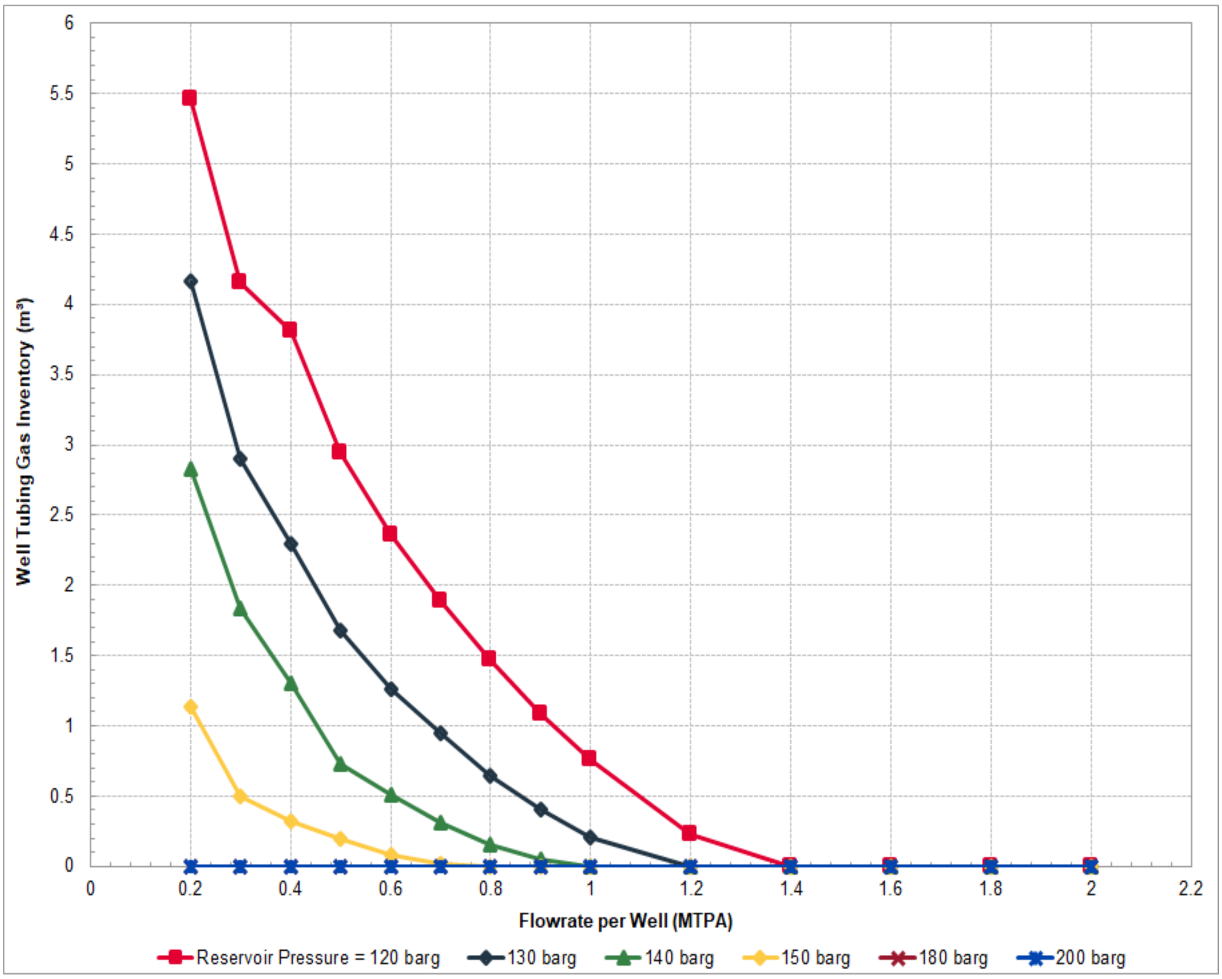


Figure 55 Gas Pocket Volume vs. Injection Rate and Reservoir Pressure

6.4.5 Abnormal Events

Should a loss of containment occur at the tree, any liquid or dense phase CO2 above a closed SSSV will boil off (see **Figure 56**), with the temperature at the gas-liquid interface around -28°C. This “cold front” moves slowly down the well until it encounters the SSSV where it is possible for further cooling to take place. If the SSSV has a small leak (which is permitted under the API specification for a hydrocarbon SSSV) then continuous cooling can continue at the SSSV with the lowest temperature reaching sublimation point at 1 atmosphere (-78.5°C) in theory for a dry tree.

For a subsea application, the water depth creates a head of pressure which reduces the delta-P for J-T cooling; in the case of NZT/NEP with ~60 m of water, the worst case leak would produce a temperature of around -55 deg C.

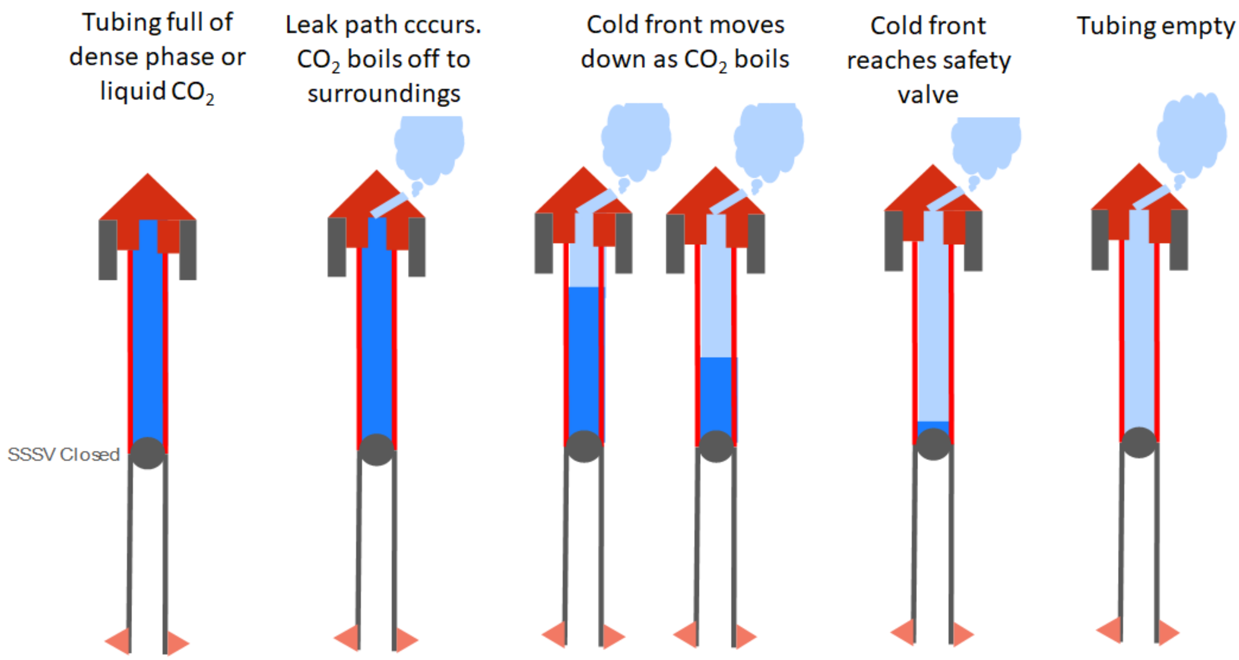


Figure 56 CO2 Depressurisation with Loss of Primary Containment8

A SSSV qualification programme will therefore be required to support this project, and a potential Joint Industry project (JIP) is being discussed with partners. A lowest common denominator temperature is likely to be used to support dry and wet tree applications, co-incident with the -78.5 deg C figure for CO2 sublimation at 1 atmosphere.

6.4.6 Test Events

Inflow testing the SSSV could also lead to generation of low temperatures in a similar manner to that illustrated in **Figure 56** and could take days rather than hours depending on the low-side pressure – if possible, design a test that does not cross the phase transition line

[8] Cartoon courtesy of Shell

6.5 Solids and Well Clean-Up Strategy

NZT/NEP reservoir fluid is a salt saturated brine close to 1.2 SG density with hydraulic connection to the seabed via an outcrop to the east of the field. There are no hydrocarbons present, residual or otherwise. This means that reservoir fluid cannot flow to the seabed naturally.

This limits well clean-up options unless artificial lift is employed, and at present a notional plan is that to surge the well and flow back part of the tubing contents (base oil) depending on how much sump is available and how much confident there is that debris will fall into the sump.

This aspect of the well design and operations planning will be worked in Define.

6.6 Tubing Metallurgy and Elastomer Selection

A full metallurgy and elastomer assessment has not been carried out at this stage. A preliminary position has been taken based on the injected fluid compositions shown in Table 7 and is summarised in this section which also aligns with general CCUS industry practice.

6.6.1 Free Hydrogen

The injection stream potentially has up to 1%mol H2 as a worst case. In early life with the well shut in, there is not enough reservoir pressure to maintain the fluid in dense / liquid phase all the way up the tubing, and there will be a small gas cap at the top of the well (0).

Hydrogen is likely to segregate out and sit at the top of the well at a concentration potentially an order of magnitude higher than the 1% in the stream

This may have a bearing on downhole material selection:

- Hydrogen gas can degrade properties and is not something that is typically considered for downhole materials, but generally will result in a drop in ductility and toughness though it is not expected to be significant
- Elastomers and seals may need further qualification

Ultimately, there is likely to be a full qualification program undertaken as the project progresses and material selection is confirmed.

6.6.2 Oxygen

The injection stream will be passed through an oxygen removal unit (ORU) as part of the onshore process plant, with the nominal O2 specification regulated at~10ppmv. The engineering team is reviewing the operation of these ORUs in dispatchable cycles; they operate at ~150 deg C, and therefore there is the potential for the stream to be off-spec at start-up. To mitigate this, a study is on-going to look at the feasibility of removing the ORUs completely and specifying the downstream metallurgy to allow higher oxygen levels.

For wells, this would entail using a high-nickel casing and tubing in all flow-wetted areas which would increase cost and novelty. This BoD assumes oxygen control at 10ppmv.

6.6.3 Production Tubing

Due to the need to flush halite precipitation in the near-wellbore region with fresh water, all flow-wetted OCTG pipe will be SM25CRW Super-Duplex to avoid carbonic acid corrosion.

Fibreglass-lined carbon steel pipe is used extensively for dry CO2 injection particularly in the USA for EOR wells, but due to the need for water washing in Endurance, the smallest leak in a connection sealing ring or crack in the fibreglass lining[9] would allow corrosive fluids to contact the base pipe which would result in rapid corrosion and integrity loss; therefore GRE-lined pipe has not been considered for NZT/NEP.

6.6.4 Downhole Equipment

Engineered equipment will be Alloy 925 or a similar nickel alloy to resist carbonic acid corrosion. Further work will be done as part of the SSSV qualification programme as many of the cryogenic low temperature steels used in medical and physics research are austenitic materials (e.g. 316 SS which is already widely used in the oil and gas industry).

6.6.5 Hydraulic Control Lines

825 is the standard material for oilfield control lines. Its mechanical properties are relatively constant from cryogenic temperatures (-150 deg C) to in excess of 500 deg C and is suitable for use on NZT/NEP.

6.6.6 Elastomers

An elastomer selection report has not been commissioned yet. A preliminary view suggests at least two suitable materials:

- FKM Fluoro-elastomer with ultra-low temperature capabilities (for example James Walker Vermilion 1) with sealing capacity confirmed down to -76 deg F (-60 deg C) in product configured testing
- Low Temperature HNBR (for example James Walker Vermillion 5/ Elast-O-Lion 985)

Other suppliers besides James Walker (Parker, Green Tweed etc) offer similar products and the service companies will recommend suitable elastomeric compounds from their range or suppliers when tendering is carried out in Define.

[9] Cracking may be exacerbated by thermal cycling for dispatchability

6.7 Reservoir Summary

6.7.1 Geology and Depositional Environment

The Bunter sandstone formation comprises several large-scale fining-upwards units in which predominantly fluvial and aeolian sandstones fine upwards into siltstone and claystone alternations of the playa margin facies. Lower permeability facies such as clay-rich playa mudstones and playa margin flood plain siltstones, deposited during periods of low energy or lake expansion, are abundant in the Lower Bunter. Coarser grained deposits are more common in the middle and upper parts of the Bunter Sandstone.

Cements (dolomite/halite cement and patchy bleached cement), silty mud-crack surfaces and cemented surfaces are recognised as potential barriers to flow in the reservoir; however, the sands in the Bunter Sandstone Formation are expected to be connected on a large scale as any identified baffles are not laterally continuous.

The main laterally pervasive band (CB1) is high in the reservoir, ~20m below the cap rock and may be a partial barrier to vertical flow. It is correlatable across all three wells on structure but is still likely to have pathways through it. Note that although correlatable, logs suggest CB1 lithotypes within the band are not the same across all 3 wells, hence there is expected to be some vertical communication (**Figure 58**).

Figure 57 shows the depositional environment of the Bunter Sandstone Formation at the storage site.

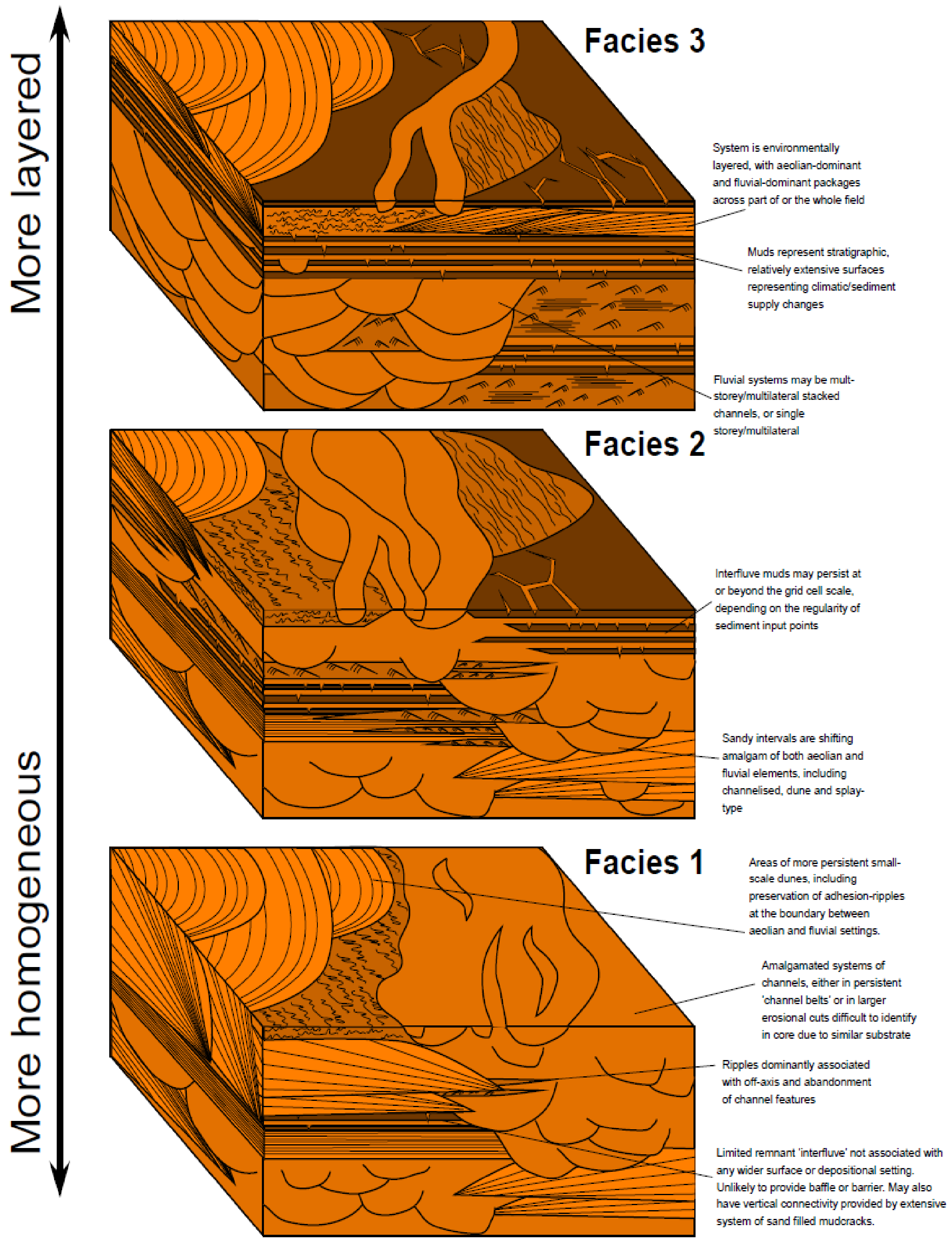


Figure 57 Representation of the Bunter Sandstone Depositional Environment around 42/25d-3

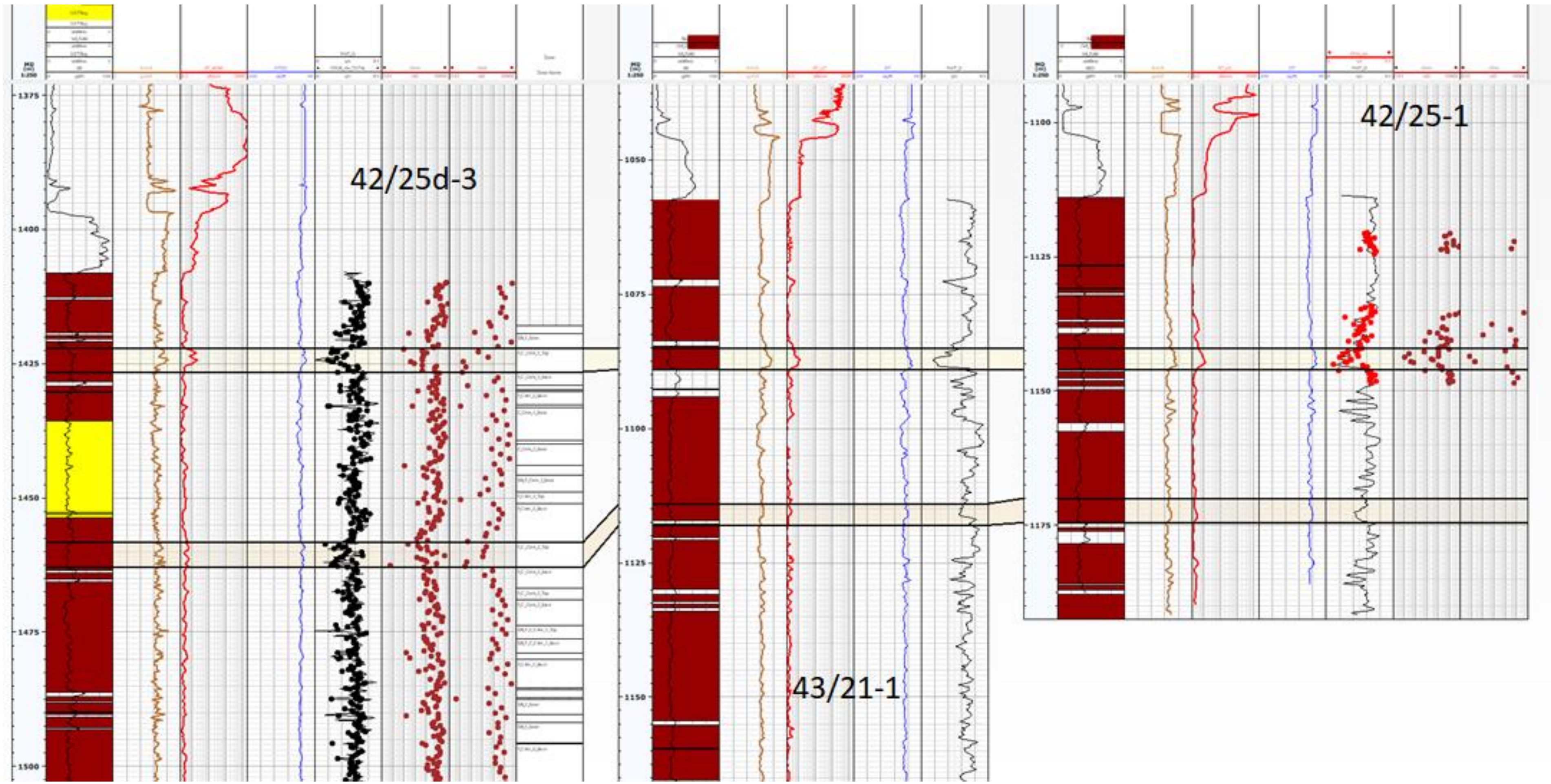


Figure 58 Candidate Continuous Baffle 1 (CB1) Attempted Log Correlation

Figure 59 and Figure 60 show log and schematic cross-sections of the Bunter around the NG 42/25d-3 well, depicting potential permeability baffles and barriers

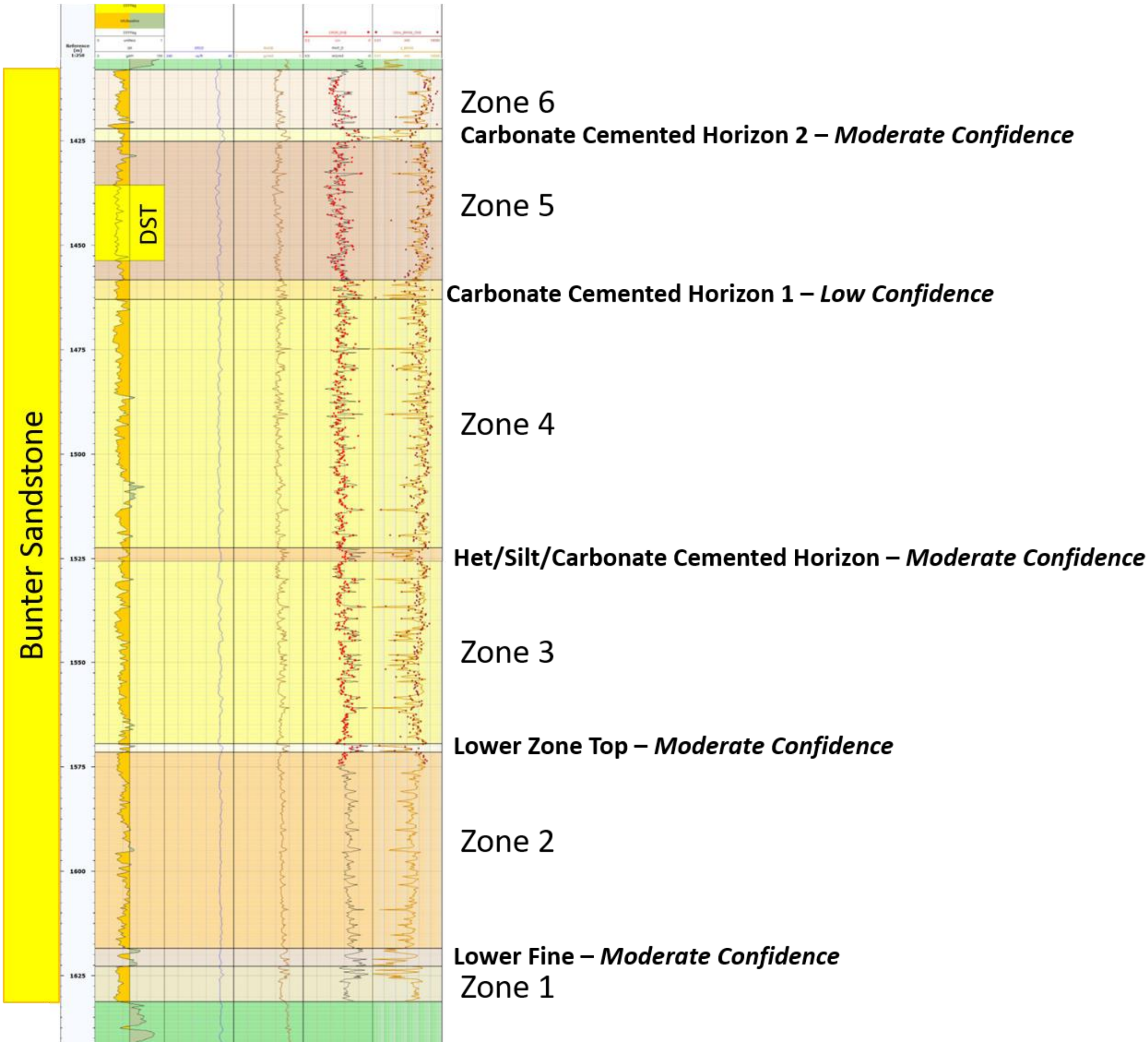


Figure 59 42/25d-3 Log Showing Baffles and Barriers

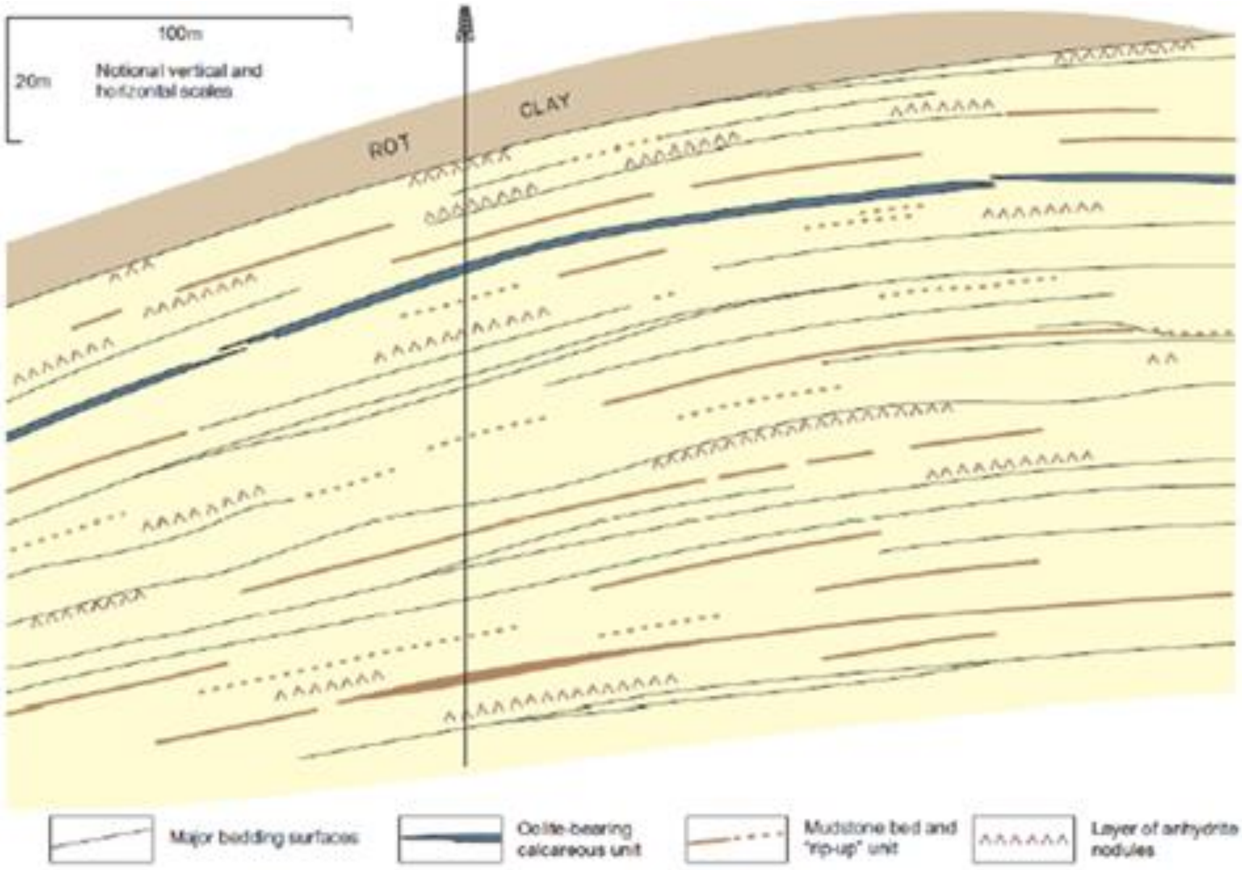


Figure 60 Cross Section at 42/25d-3 Potential Geometry of Permeability Baffles and Barriers[10]

6.7.2 Well Test

National Grid carried out an injection test on the Endurance appraisal well, as part of the cancelled White Rose project in 2013.

The test aimed to inject ~ 5000 bwpd for 24 hours, followed by a 48hour fall-off test and then a step-rate injection test at 5000, 10000, and 15000 bwpd.

Likely scale precipitation led to rapid blockage of the perforations and subsequent fracturing during the injectivity test indicated a high risk of $CaSO_4$ scale deposition when Endurance brine is mixed with sea water)

Interval	Depth (m MD BRT)	Depth (m TVDSS)
#1	1435.6 – 1453.6 (18m)	1396.3 – 1414.3 (18)

Table 42 42/25d-3 Injection Test Perforated Interval

Summary of well test results

- Radius of investigation calculated at 1.3 km
- No lateral barriers observed once tidal effect corrected
- Kh ~ 260-300* mD with radial, homogeneous model with partial penetration
- Very low vertical permeability ~ Kv/Kh = 0.001- 0.004 (0.1-0.4%)
- Low macro-scale Kv/Kh (over 10-100's meters, < 1%) & moderate Kv/Kh from Vertical Interference Test #1 (over smaller scale 1's meters, ~10%)
- N.B.: Non-uniqueness: match could be found with higher Kv/Kh and lower Eff. Thickness for instance (i.e. well has not seen the entire reservoir section)
- * White Rose brine viscosity at 0.95 cp – BP brine viscosity modelled at 0.99 cp for reservoir conditions & 250,000 ppmw

6.7.3 Petrophysical Properties

Property	Value
Reservoir Rock	Sandstone
Reservoir Type	Fluvial-Aeolian Clastics
Reservoir Datum Depth	1300m TVDSS
Reservoir Top Depth	
Reservoir Bottom Depth	
Initial (and minimum) Reservoir Pressure at Reference Depth	2030psi
Shut in Wellhead Pressure	970-1350psi (early life 67 bara, late 93 bara)
Spill Point	1450m TVDSS
Temperature at Reference Depth	57deg C
NTG (P10-mean-P90)*	74- 95 – 97 %
Porosity (P10-mean-P90)*	16.4 - 22.5 - 24.1%
Permeability (P10-mean-P90)*	100 – 300 – 500 mD

Kv / Kh	Macroscale: 0.04 (DST 42/25d-3 DST), core scale ranging from 0.01 to 10% (heterolithic / cemented to clean facies)
Pore Volume Compressibility	4*10-6 /psi
Thermal Expansion	Halite: 4.0 (3.85@20-40degC, 4.24@40-60degC), shale: 1.4, sand: 1.2
Poisson's Ratio (sand)	0.19 avg. (static), 0.27-0.36 (dynamic)
Young's Modulus	1.45*10-5 avg. (static)
Formation Dip & Azimuth	Near crest: dip ~4.25 degrees, azimuth ~300 degrees, down-flank: dip 1-2 degrees, azimuth 270 degrees

* Predicted average reservoir properties for a penetration of the entire Bunter sandstone, representative of a single new well. A campaign average would have a much smaller range.

Table 43 Petrophysical Properties

Property	Pure CO2	High N2	Comments
Density (bottom hole flowing)	960 kg/m3	922 kg/m3	BHT 5 deg C, BHP 160 bar (cold liquid)
Density (initial conditions)	607 kg/m3	550 kg/m3	T res 56 deg C, P 140 bar (hot, supercritical)
Density (late life)	748 kg/m3	708 kg/m3	T res 56 deg C, P 200 bar
Viscosity (bottom hole flowing)	0.1086 cp	0.089 cp	BHT 5 deg C, BHP 160 bar (cold, liquid)
Viscosity (initial conditions)	0.046 cp	0.043 cp	T res 56 deg C, P = 140 bar
Viscosity (late life)	0.063 cp	0.058 cp	T res 56 deg C, P = 200 bar

Properties derived from Peng Robinson in PVTp

Table 44 Fluid Properties

6.8 Injectivity and Tubing Performance

6.8.1 Reveal Numerical Injectivity Modelling

A numerical injectivity study was carried out using Petroleum Experts' "Reveal" application, indicating the following:

- The risk of vertical fracture growth is manageable and low based upon screened tested cases - no case presents a fracture reaching top Bunter by the end of injection
- The study has demonstrated the value of leaving an (upper) section of the Bunter unperforated (at least 20-30 meters), both for pressure limit and conformance
- Injectivity is sufficient in all cases that have sufficient Young's modulus to fracture – except for a short initial period where no fracture occurs and the skins were large (S =30)
- Fractures follow the temperature profiles. The tendency is for positive feedback where cool CO2 reduces the temperature of the formation and fracturing occurs. Then more CO2 flows into the fractures causing more cooling and the process is repeated and enhanced.
- The most important parameters are the combination of Young's modulus and the LTEC which drive the thermo-elastic stress reduction.
- The safe BHP limit (3,250 psia at 1300 m TVD ss) was approached only in case where injectivity is very low for crestal well #4 (< 0.1 MMscf/d) with no fracture (low YM) and high skin (S=30). This is a scenario of low probability (evidence of fracturing during the 2013 injectivity test in 42/25d-3) which would lead to rate curtailment.
- Skin build-up (and associated injectivity loss) is likely to be offset by thermal fracturing. In the low probability case where fracturing does not occur and there is formation damage with low Young's Modulus and high skin, late life BHP could require curtailment due to the cap rock pressure limit for the crestal well. This indicates the importance of avoiding high skin in order to achieve acceptable injection rates across the full uncertainty range.

6.8.2 Average Rate Requirement

The Wells Statement of Requirements requires an average design capacity of 1 MTPA (million tonnes of CO2 per annum) per well over 25 years. The CCUS industry tends to use mass rates rather than volumes due to the phase changes throughout CCUS systems. For comparison, 1 MTPA CO2 is approximately comparable to 52 mmscf/d of gas or ~19 mbd of water injection.

The design capacity of 1 MTPA is not an injectivity or tubing constrained number, but is taken from industry benchmarks to take into account uncertainty in injectivity impairment from relative permeability, mineral or other skin increases such as halite precipitation which are difficult to model conventionally.

6.8.3 Peak Rate Requirement

Assumed peak injection rate will be 1.5 MTPA per well. This is to cope with outages for intervention, water washing and other losses of availability over a year, and is within the P50 Reveal injectivity modelling envelope.

1.5 MTPA per well would represent ~ 38,000 reservoir barrels per day as a supercritical fluid in the reservoir which would be on the high side of water injection analogues (BP Caspian high rate WI wells inject up to ~45 mbd)

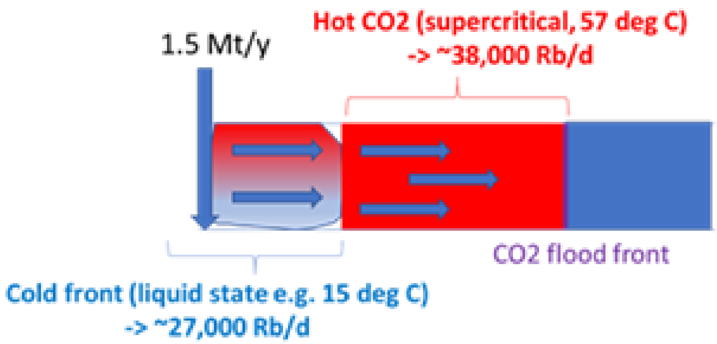


Figure 61 Peak Rate Reservoir Flow

6.8.4 Tubing and Liner Size Selection

A 5 ½” tubing string has been selected:

- 5 ½” tubing easily meets the required peak injection rate. There are no turn-down limitations
- Smaller tubing is not required to give additional friction to reduce choke delta-P to mitigate J-T cooling
- The low temperature SSSV will be a 5 ½” item – this meets the requirement for other projects and there are benefits with standardisation
- If a lubricator valve is fitted in the string (i.e. if a single wireline perforating run is adopted), this will also be a 5 ½” nominal item.
- The liner is nominally 5 ½” also. This gives the best resistance to cement stress in an 8 ½” hole and also enables intervention access with guns, PLTs and shut-off patches if required; however an option for a 7” liner will be carried through Define to accommodate a perforated inner string fibre optic surveillance option which will likely need 3 ½” pipe (ID 2.922”) to keep upside injection capability (see Figure 65).

6.8.5 Tubing Performance

A well performance model was built in Prosper to assess initial injection rates:

- 5 ½" cased and perforated completion
- Base case skin of 5
- 60 m (200 ft) of perforations in a formation thickness of 200 m (650ft).
- Permeability 120mD
- Sensitivities made around reservoir pressure, skin and use of a perforated tail pipe for fibre conveyance
- All work assumes matrix injection; a thermal fracturing seems likely with low BHPs (~13 deg C) and rock UCS values in the 2000 psi to 4000 psi range and a study has been commissioned to investigate this for delivery in ~3Q2020
- Although conformance across the whole perforated interval is assumed, the thermal fracturing work will likely show a smaller zone taking fluid, although it is expected that CO2 migration will occur throughout the reservoir away from the wellbore. This limited entry injection will effectively have a skin component comprising a partial penetration (+ve) and a fracture conductivity component (-ve). The 5-30 skin ranges in the IPR modelling will conservatively encompass these effects.

Figure 62 below shows the base case injection performance for the base case well with 5 ½" tubing. It can be seen that for the nominal WHIP of 110 bar, the peak rate requirement of 1.5 MTPA (~84 mmscf/d) is achievable even with a skin of 30, all the way from initial reservoir pressure of 140 bar to a final reservoir pressure of 200 bar.

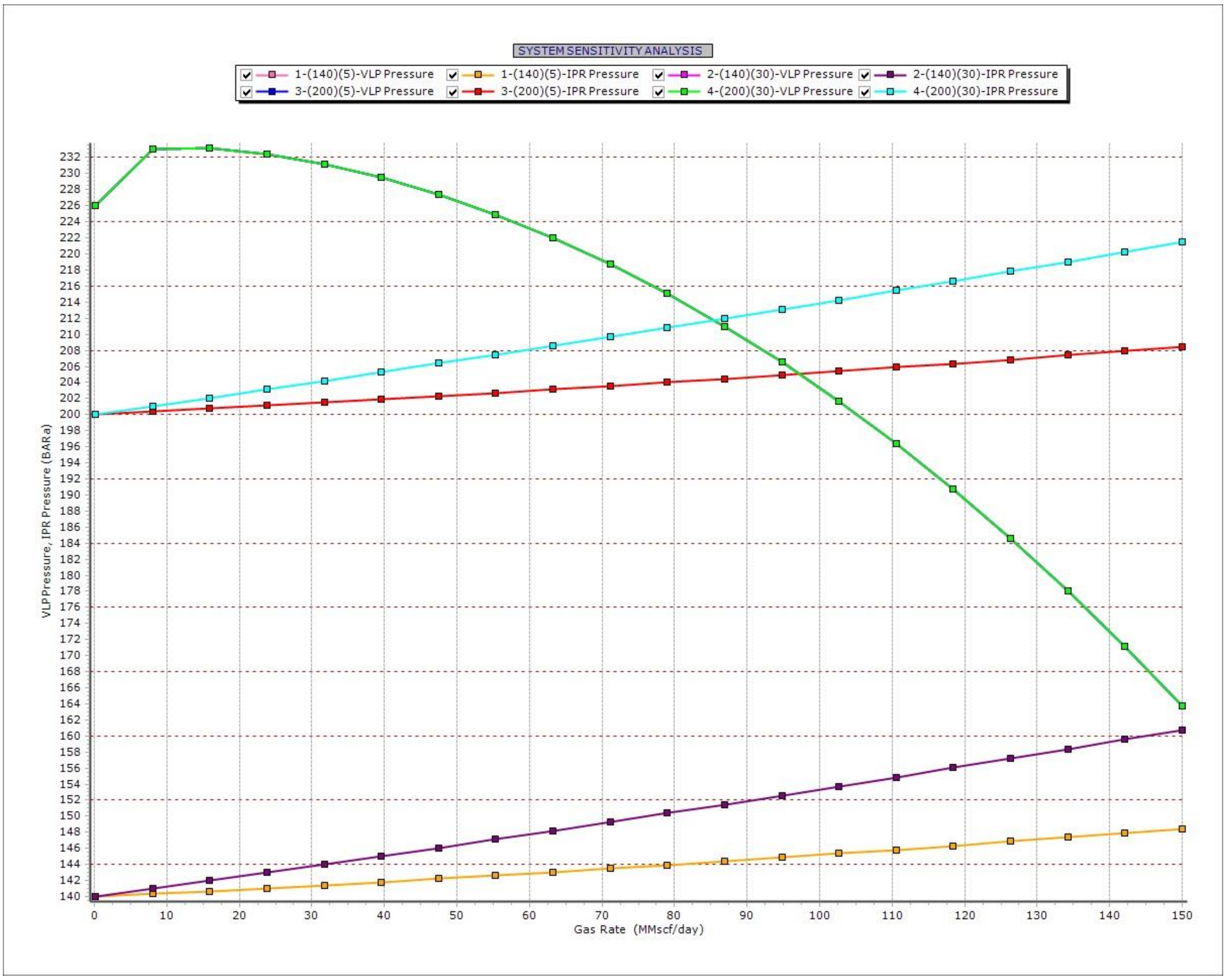


Figure 62 Tubing Injection Performance (5 ½" Tubing, WHIP 110 bar, Skin 5-30, Pr 140-200 bar)

Figure 63 shows the injection performance with the same parameters as Figure 62 but with a 3 ½" perforated tailpipe carrying a fibre to TD (see Section 0). Injection is assumed to occur at mid-perf, but further modelling will be undertaken to analyse annular flow between tailpipe and liner which is not included at present which makes the current view slightly conservative.

The key point to make from this plot is that although peak injection is achievable in early life with virgin reservoir pressure, as the field pressures-up towards a final pressure of ~200bar, only the average rate of 1 MTPA (~52 mmscf/d) is achievable no matter what skin is assumed. The point at which peak rate cannot be achieved is with a reservoir pressure of approximately 170 bar if a worst case skin of 30 is assumed.

Circumstances may mitigate this as the development progresses; for example, brine production might be arranged to keep reservoir pressure below a point where the peak rate of the time can be met, or more wells may be available to distribute injection more widely across the field and have sufficient sparing capacity.

These considerations will influence the decision on fibre installation in Define.

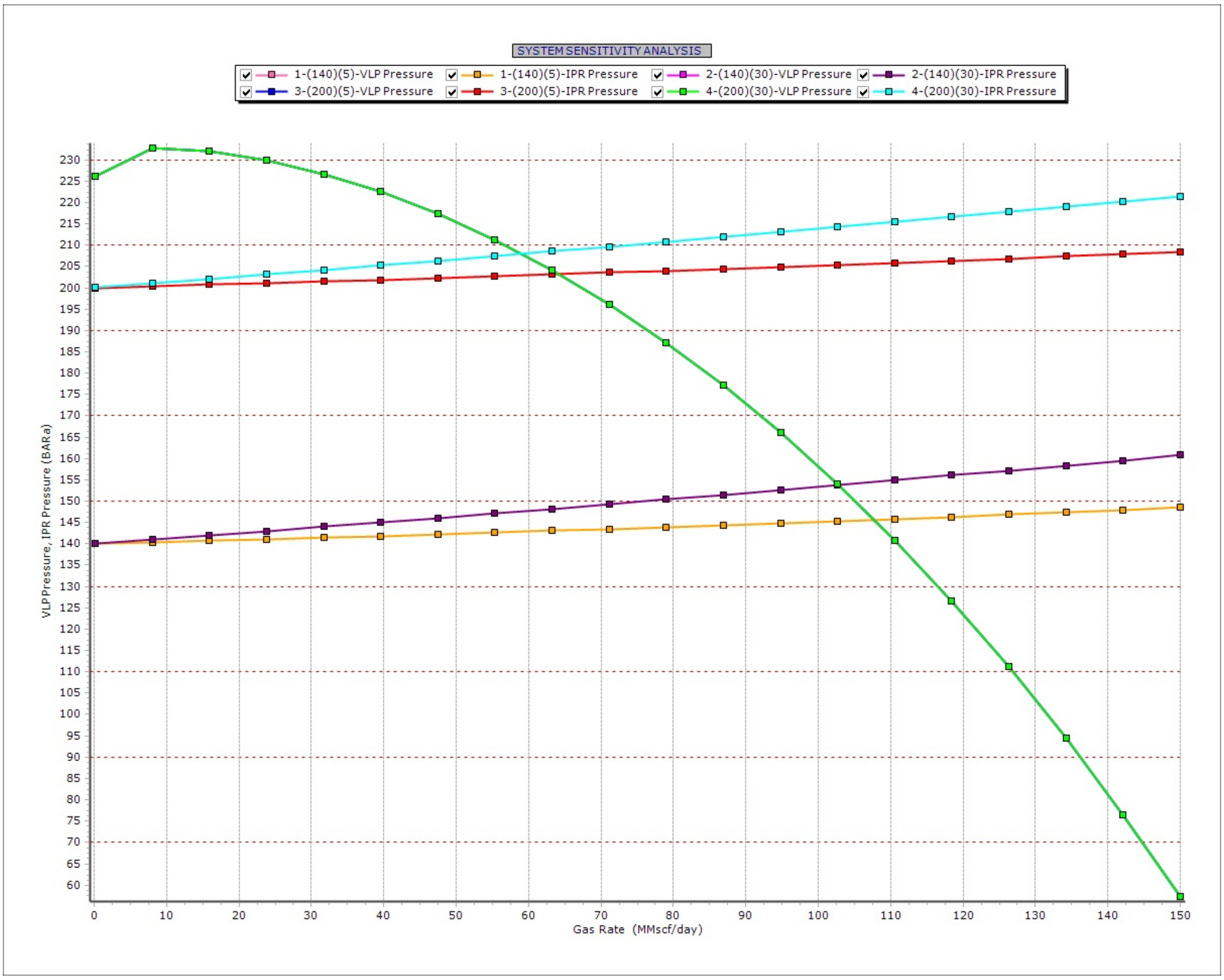


Figure 63 Tubing Performance with 3 ½" Tailpipe to TD Injecting Mid-Perf at 1950 m MD

6.9 Completion Fluids Design

6.9.1 Running Fluid

As the reservoir is sub-hydrostatic (normally pressured by seawater from the via an outcrop, with dense brine in the pore space), mud weight in the reservoir section is largely determined by well-bore stability issues at up to 60 deg deviation which may not be a concern once the liner has been cemented.

That said, the reservoir section mud weight is expected to range up to ~1.36 SG. Formation damage testing has not been carried out at this stage, and so both monovalent and divalent brines are indicated for suitability:

- For monovalent brines, NaBr covers the range 1.0 to 1.52 SG and so could potentially be used for all well inclinations. Clearly NaCl or KCl will be considered where lower mud weights have been used in the reservoir section.
- For divalent brines, CaCl2 almost covers the full range, but as it would be saturated at 1.35 SG, it may not be suitable for the worst case WBS requirement. In this case, a CaCl2 / CaBr2 blend (1.0 to 1.8 SG) would be suitable.
- The perforating strategy has not been fully defined yet, and may dictate use of kill pills depending on perforating method, use of an extended tailpipe (fibre option) and timing relative to completion installation.

6.9.2 Packer Fluid

There is no requirement for kill weight fluid in the 'A' annulus. The key criteria are that any fluid should not freeze when subjected to temperatures below 0 deg C at start-up, low rates in early life with the reservoir pressure close to initial conditions (**Figure 52**) and in abnormal situations, should not form corrosive products should a tubing or packer leak occur (carbonic acid), and should not form CO2 hydrates in the same leak scenario.

Note that because the low temperature scenarios are generally transient, the risk of the annulus freezing as a whole is low because of the annular fluid thermal mass (pending detailed thermal modelling). Nonetheless, a low temperature packer fluid would be preferred to prevent localised freezing for situations noted above.

- MEG 90. Density is 1.11 SG, but will freeze at -13 deg C which is very close to the -10 deg C estimated for early life start-up. Unlike water, it contracts when it freezes, so if the freezing point was deemed acceptable, there would not be a risk of casing burst / tubing collapse if the temperature fell below -13 deg C.
- Base oil. The key parameter is the pour point temperature; of the common base oils used by BP in the North Sea, Clairsol 370 has a pour point of -29 deg C which would work well for NZT/NEP, and would just require some consideration of abnormal

situations where temperature could fall below this transiently (e.g. LOPC). Regardless, there is a wide range of base oils available with pour points as low as -63 deg C.

- Insulating Fluids. These work by reducing conduction (glycols or oils as a base fluid) and convection by gelling the fluid. These would provide additional mitigation for cement stress from thermal cycling with dispatchability above the packer. For example, MI's Isotherm is an oil-based system that could potentially be developed to suit NZT/NEP's low temperature and anti-corrosion requirements. Further work would be needed to determine if additional cement stress mitigation was required, and then if the insulation would be sufficient to reduce the temperature change over typical dispatchable periods. In addition, although the insulating properties in the 'A' annulus might reduce peak temperature changes for the 9 5/8" casing cement above the packer, it would in turn mean a lower BHT and more risk to the liner cement through larger thermal cycles. A gelled packer fluid might make workovers more complex as difficulty displacing these fluids has been observed in the field.

7.0 Lower Completion Selection

7.1 Overview

The Bunter sandstone is well cemented with a high UCS (range ~2000 psi to ~4000 psi, generally trending stronger with depth). Reservoir pressure will increase over time due to CO_2 injection and <100% displacement when brine production is eventually required, and so the net pressure on the sand grains will decrease.

Note that for brine production wells, the lower completion design may be different and tend towards a stimulated design of some sort (e.g. frac-packs), in order to increase effective kh and well rate. This is because the localised increase in reservoir pressure at the brine production wells is unlikely to be large enough to drive high rates which would otherwise mean more wells. However, brine production wells are not included in Phase 1 and are not considered in this document.

7.2 Sanding Propensity

7.2.1 National Grid Evaluation (White Rose Project)

In March 2012, prior to the appraisal well 42/25d-3 being drilled, a sanding study was carried out on the Endurance area target Bunter sandstone using offset well log derived rock strength data (42/25-1 and 43/21-1 crestal wells) that was calibrated using 42/25-1 core derived uniaxial compressive strength (UCS) and thick wall cylinder (TWC) rock mechanic test results. An in-situ stress model was developed based on offset and field wells to date including LOT and FIT data sets. The sanding model was developed to consider a range of drawdown, depletion and injection conditions to consider both lifecycle injector and producer well sanding risks.

The study indicated in that in general terms rock mechanical strength increases with depth. This is matched by the inverse trend of reservoir quality decreasing with depth. Results indicated that for a CO_2 injection well completed with a cemented and perforated sand face solution, there would be minimal risk of sanding given a rising lifecycle reservoir pressure where matrix stress is reduced over time as pore pressure rises.

As an aside, in a drawdown scenario of up to 69bar, sand production risk was considered low. If the drawdown was increased to 138bar then some sand production from the weakest interval was expected.

Additionally, given a desire to perforate in the middle and lower half of the reservoir where strengths are highest then sanding risk is reduced still further; even without a reservoir pressure increase, no drawdown case poses a threat with respect formation failure and wellbore sanding.

7.2.2 Composite Logs with Calibrated UCS

Figure 64 shows a composite log for the National Grid 42/25d-3 well, including a synthetic UCS curve derived from the sonic log. Overlaid on the UCS curve are the UCS measurements from the core mechanics testing, which indicated good correlation between core and log.

The key point to make from this is that within the resolution of the log, UCS does not fall below 2500 psi across the entire Bunter sand, but in particular, if a ~80m standoff is taken from the base of the Rot Clay at 1369m TVDSS to ~1450m TVDSS, the UCS is consistently 5000 psi or greater.

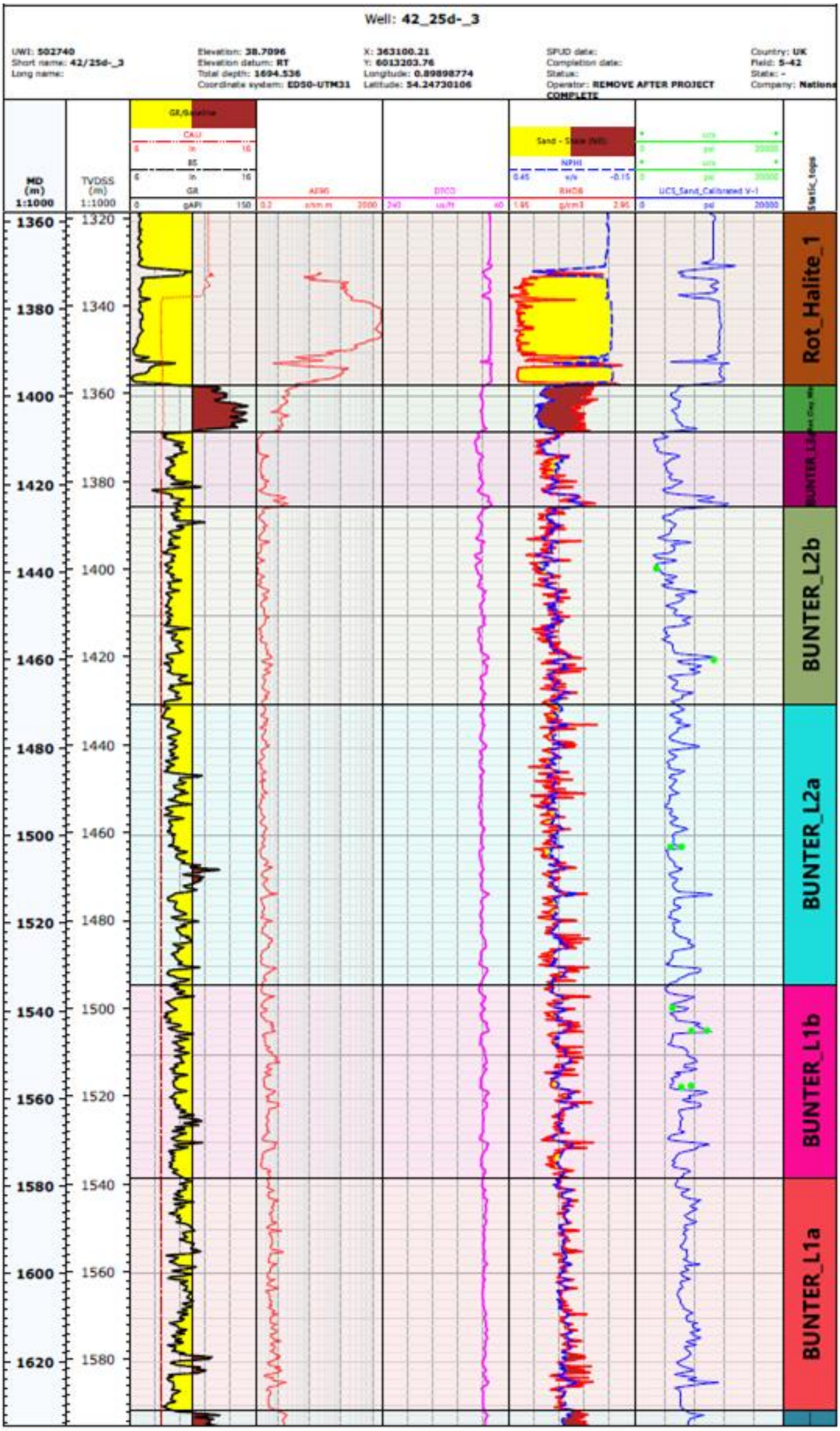


Figure 64 42/25d-3 Composite Log with UCS

7.2.3 Cross Flow

The reservoir is quite heterogeneous if 25d-3 core is fully representative with better properties in the upper Bunter L3 and L2 with poorer section in the L1 (lower Bunter). Crossflow may occur if any pressure differential develops over time.

Poor sweep or conformance for fresh water pumped to dissolve halite precipitation may create zones of poor permeability which will further exacerbate future halite deposition and may create zones that are not fully charged which would create crossflow potential as time goes by; however, such zones would be local rather than laterally extensive. As an analogue, the Aquistore project (Canada) has seen halite precipitation in poorly swept or un-swept intervals but have not reported any issues with crossflow.

The largest possible dP would be final – initial reservoir pressure which is around 60 bar; the lower completion strategy must be robust to this.

7.2.4 Degradation of Mineral Cementation

CO2 by itself is unlikely to have any interaction with carbonate minerals. It's the presence of water (and therefore carbonic acid) that has the potential to cause issues; this aligns with the desire to keep the brine – CO2 interface deep in the reservoir (to minimise halite precipitation) so any potential local sandface degradation is minimised further.

In theory, the dissolution of carbonate mineral cements could potentially lead to sanding. The uncertainty is in two areas; firstly where these minerals are present and in what quantities, and secondly the reliability of model thermodynamic data which currently predicts either a very small amount of dissolution or a very small amount of precipitation of dolomite depending on the database used.

Equilibrium modelling to date indicates that the only mineralogical changes likely to be observed following the saturation of reservoir brine with CO2 are slight dissolution or precipitation of carbonate minerals. These minerals are not abundant in the reservoir so their alteration is unlikely to have a substantial impact on the overall reservoir quality; however, the rate of fluid flow through a perforation might be such that an equilibrium model is no longer appropriate due to rapid removal of any dissolved material. This physical process is likely to dominate over the chemical ones in these circumstances, again aligning with the desire for the brine – CO2 front to be kept away from the near wellbore.

Priority case	Details	System description	Likely processes	Modelling outcome
Priority 3 (A) Behaviour in the Bunter How will CO_2 react with typical Bunter?	4722 ft brine XRD plug 343 Initial pH 5.25	Plume of water-saturated supercritical CO_2 in Bunter reservoir sandstone Static due to physical trapping	CO_2 unlikely to have substantial direct interactions with minerals in reservoir, no significant damage to the reservoir is expected	n/a
Priority 3 (B) Behaviour in the Bunter How will CO_2 react with typical Bunter?	4722 ft brine XRD plug 343 Initial pH 5.25	CO_2 saturated hypersaline brine Static fluids with limited physical extent	Low pH and unsaturated brine will interact with more reactive minerals, including carbonates and some aluminosilicates; immobile brine will be pH buffered and may see some mineral precipitation.	Anhydrite, halite and feldspars may dissolve, dolomite may precipitate. Impact on RQ is negligible
Priority 3 (C) Behaviour in the Bunter How will CO_2 react with typical Bunter?	4722 ft brine XRD plug 343 Initial pH 5.25	Hypersaline brine containing some dissolved CO_2 Static fluids with limited physical extent	Low pH and unsaturated brine will interact with more reactive minerals, including carbonates and some aluminosilicates; immobile brine will be pH buffered and may see some mineral precipitation.	Anhydrite, halite and feldspars may dissolve, dolomite may precipitate. Impact on RQ is negligible
Priority 3 (D) Behaviour in the Bunter How will CO_2 react with typical Bunter?	4722 ft brine XRD plug 343 Initial pH 5.25	Hypersaline brine containing some dissolved CO_2 Mobile fluid phase	Low pH brine and unsaturated fluid will interact with more reactive minerals, including carbonates and some aluminosilicates; mobile brine will prevent pH buffering possibly exacerbating dissolution of fast-dissolving minerals	n/a

Table 45 Effect of CO2 on Mineral Cementation

7.3 In-Well Monitoring

Both conventional and newer-technology monitoring are being considered.

7.3.1 Downhole Pressure-Temperature Gauge

A dual DHPTG will be fitted to monitor pressure in both the tubing and the annulus. The annulus gauge is included to allow ‘A’ annulus pressure monitoring when the fluid level drops due to thermal contraction on injection. Under these conditions, the conventional gauge in the tree is not in contact with the fluid and so does not register. An alternative is to install a nitrogen-cushion to expand to fill the void, but this is operationally more complex.

7.3.2 “Behind-casing” Pressure Monitoring

This is a technology option carried into Define. Systems are available from several vendors that allow pressure to be monitored behind cemented casing, which would enhance reservoir surveillance particularly in the cap rock in the observation well close to the crest and / or to monitor ‘B’ annulus pressure which is not directly measurable with a subsea wellhead:

- Electro-magnetic RF systems such as Halliburton’s Linx and Expro’s CaTS
- Metrol’s Paragon / Oculus acoustic transmission-based system

7.3.3 Distributed Acoustic Sensing and Distributed Temperature Sensing

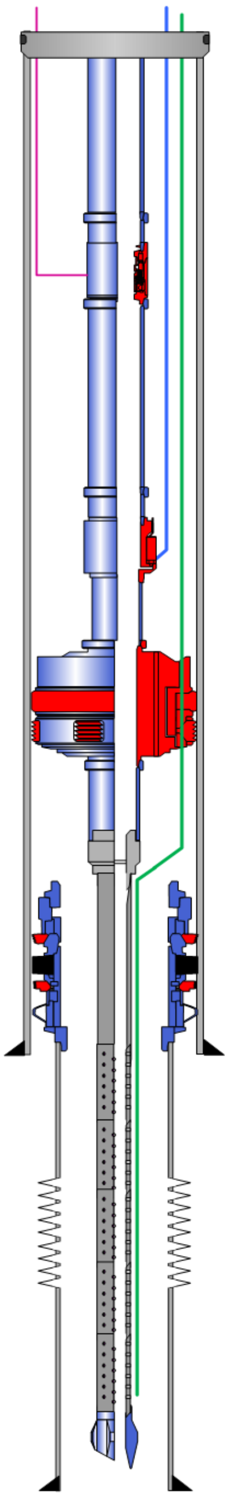
Both DAS and DTS will be carried into Define as an option. DAS would be run to the top of the packer for micro-seismic monitoring. DTS would be an advantage if run across the reservoir to monitor flow performance, although the interpretation of DTS data for CO2 injection profiling is not fully mature yet.

Although the distance from Endurance to shore is ~140km which exceeds the current fibre transmission limit of ~100km, developments are increasing this transmission distance and it is expected that this will not be a restriction when the wells are drilled. Fibre couplers are generally qualified for use in subsea trees, and equipment is available to install fibre down to the production packer across the reservoir.

At present, cementing fibre behind the production liner in a cased and perforated completion is not possible, and there are no nascent plans to address this at the time of writing. However, fibre can be run on small diameter tube that runs inside the liner, known as “fibre on a stick” or an “inner string”. This carries some risk because it prevents mechanical access for PLTs, add-perfs and re-perfs, and also may exacerbate halite precipitation in the small clearances between liner and fibre tube. The flow restriction through this inner string may also limit upside injectivity potential; clearance is needed for the clamps that hold the fibre – typically the extended pipe will be 2 3/8” (run inside 5 ½” liner) or 2 7/8” or possibly 3 ½” (run inside 7” liner) depending on what connections are used. Initial modelling suggests that 3 ½" pipe is required as a minimum to maintain the 1 MTPA target rate per well.

NZT CO_2 Injector - Inner String with DAS / DTS

Revision:	Rev 1	Date:	12 Oct 2020	Prepared by: Russ Haley
CO2 Injector		Packer Fluid:	Base Oil	Notes: All depths approximate



OD [in]	Nom. ID [in]	L [m]	Top [mTVD SS]	Top [mMD BRT]	Description
			58		5 1/2" Subsea Tubing Hanger
					5 1/2" VAM Top HT Tubing (25% Chrome Super Duplex)
			525		5 1/2" SSSV (Alloy 925 or similar)
					5 1/2" VAM Top HT Tubing (25% Chrome Super Duplex)
			957		9 5/8" Casing TOC
			1082		5 1/2" DHPT Dual Gauge Mandrel (tubing and annulus, Alloy 925 or similar)
			1107		9 5/8" x 5 1/2" Permanent Packer (Alloy 925 or similar)
			1157		7" Liner Hanger (Alloy 925 or similar)
			1232		9 5/8" Casing Shoe (flow-wetted 25% Chrome Super Duplex)
			1238		Top Bunter Sandstone
			1318		Top Perforation (standoff from Rot Clay)
					3 1/2" perforated pipe inner string
			1418		Bottom Perforation
					7" VAM Top HT Liner (25% Chrome Super Duplex)
					DAS / DTS Fibre Bundle
			1512		Top Bunter Shale
			1549		7" Liner Shoe

Figure 65 Notional Fibre Optic Inner String Configuration

7.3.4 Expro's "Reveal" Electrical System

An alternative to DTS is an electrical distributed pressure and temperature system, and this technology option will be carried into Define / FEED. For NZT/NEP, this system would be configured as an inductive coupling in the tubing with an inner string hung from the coupling to run the cable with in-line sensors into the cased and perforated liner. One advantage of this system is that although as a whole it is only TRL3, the coupling itself is TRL6 and could be run at the time of completion and the inner string run subsequently; that said, as the first wells will be completed in 2024, it is likely to be fully qualified by then.

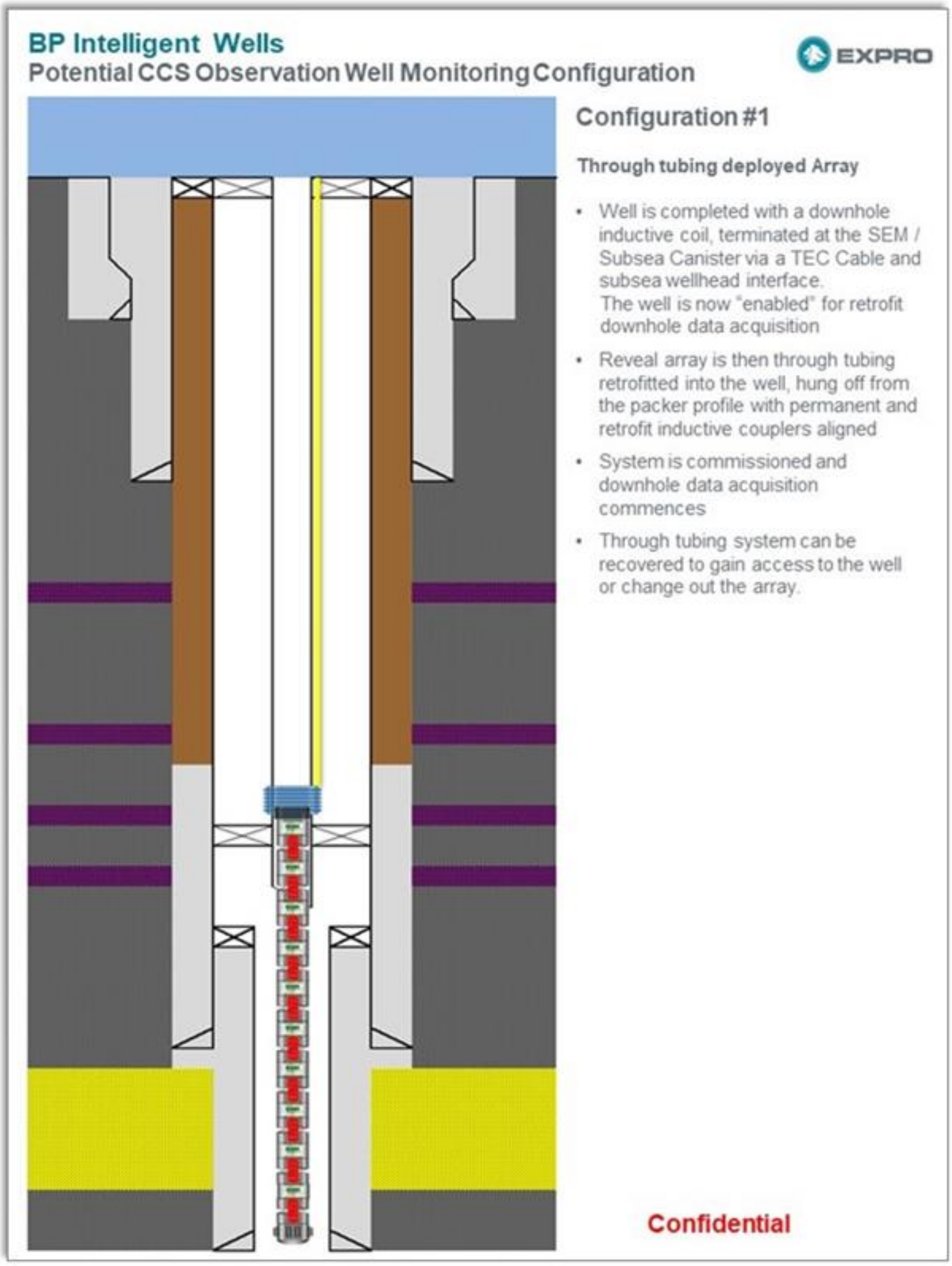


Figure 66 Notional Expro Reveal Configuration

7.4 Lower Completion Options

7.4.1 Sand Control / Screen Completion

Although a screen / sand control completion is not required for sand-control purposes per se, there is one advantage to using a screen-based lower completion; running a screen completion allows fibre to be run in conduits through the screens across the reservoir. This is routinely done for dry trees with a pump-around system, and is also feasible for subsea trees with a feed-through and wet-mate system at the gravel -pack packer.

There are several disadvantages though:

- Sealing the store at cessation of injection requires a robust abandonment program. This is more difficult to achieve and verify with a screen completion, particularly with an existing fibre conduit through the screens which could create a future leak path.
- Boundary Dam experience suggests that halite precipitation in the near-wellbore can “extrude” back into the wellbore particularly in areas of low permeability where the CO2 / brine interface front has not been pushed far from the well. A gravel pack completion in particular may exacerbate this effect allowing halite precipitation through the gravel.

The disadvantages outweigh the advantage of the potential to place fibre across the reservoir, and so a screen-based completion for non-sand control purposes is ruled out.

7.4.2 Downhole Flow Control

The need for conformance control by DHFC or other isolation means has not been demonstrated. Reveal injectivity modelling (see Section 0) suggests that although there may be vertical “baffles”, none are expected to be laterally extensive; poor Kv/Kh is symptomatic of the geology but the CO2 will still migrate over time.

From a practical point of view, there are no clear shale breaks between zones across which to place any flow control devices.

Therefore DHFC has been discounted at this point.

7.4.3 Inner String for DTS

Another method for acquiring DTS data across the reservoir is to run an extended perforated tailpipe as a means of conveyance for the fibre as shown in Figure 65. Key aspects for this approach are:

- We need clearance for the clamps that hold the fibre – typically the extended pipe will be 2 3/8" (run inside 5 ½" liner) or 2 7/8" or possibly 3 ½" (run inside 7" liner) depending on connections. No decision has been made on 5 ½" or 7" liner sizing yet – it will depend on the cement stress and fatigue modelling for dispatchability and reservoir dilation which has yet to be modelled. It probably more likely that a 5 ½" liner will be chosen which will restrict upside injection rate.
- A 3 ½" inner string just allows 1.5MTPA in later life at 200 bar Pr (see Figure 63). Smaller strings (2 3/8" or 2 7/8") give <<1 MTPA, at least if only tubing flow is considered.
- Under-reaming is not desirable as liner centralisation will not be optimum which will compromise the cement placement.
- Running 9 5/8" casing to TD is feasible and has been done in many offset wells that target deeper gas-bearing horizons. However it is preferred that the production casing is set above the reservoir to isolate it from the effects of dilation which may impair the liner cement over time. Cement placement will be more tricky as a high density slurry is needed for fatigue mitigation.
- The well will need to be perforated and killed while running the upper completion. This may introduce higher skins and poorer conformance.

Notwithstanding the above, this option will be carried forward into Define pending further evaluation.

7.4.4 Cased and Perforated Completion

A cased and perforated completion is recommended for Endurance wells; fundamentally there are no reasons not to:

- Allows flexibility in choosing reservoir intervals
- Robust during well construction and future intervention
- Robust operationally with the expected temperature and pressure cycles (cement stress and fatigue analysis)
- Easier zonal isolation in future
- Simple abandonment for store closure

7.5 Perforating Strategy

This section presents an outline view of the perforating strategy, in line with subsurface expectations and Reveal modelling output (Section 0).

The current view is that between 80 m to 100 m of perforations will be shot in the middle of the zone, maintaining up to 60 m TVT stand-off below the base of the Rot Clay cap rock to avoid vertical fracture migration and cold CO2 contacting the cap rock.

Although there are multiple baffles in the reservoir across the entire interval (upper section due to calcite cementation, trending to finer particles in the heterolithic section at the bottom) as borne out by poor Kv/Kh, these are generally not mappable across the structure with “gaps” to flow, and gravity dominated migration will occur.

7.5.1 Vertical Wells

A fully-distributed subsea layout with vertical or near-vertical wells has emerged as the preferred case during mid-Optimize.

This is advantageous for perforating as the required interval of ~80m is within recent experience of being done in one wireline run[11].

An outline job description is:

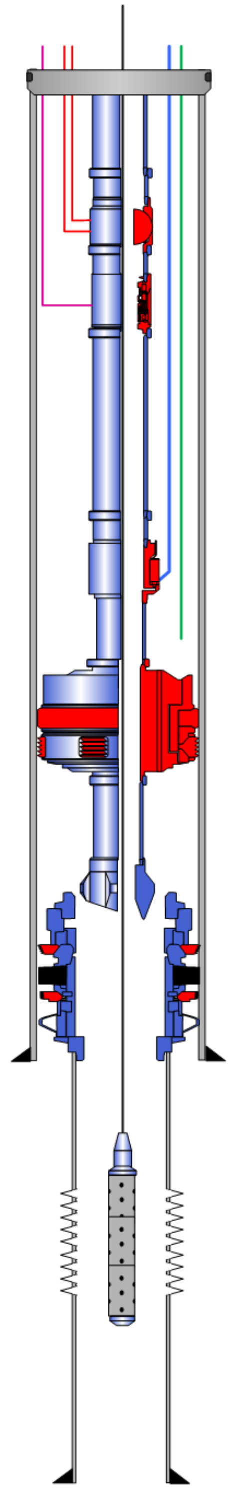
- Perforating fluid freshwater ~180psi underbalance. Alternative fluids could be base oil or a mutual solvent. Big cable pressure gear is feasible on the rig floor.
- A lubricator valve may be required in the tubing – this would require “survivability” qualification for low temperature exposure.
- Assuming a 5 ½” liner, 3 3/8” guns would be used, weighing around 12lb/ft in air. 80m of guns would weigh ~3,200 lbs.
- Cable weight ~330lb/1000ft, so at 1600m TVD cable weight is ~1800lbs
- This gives pick-up weight (air, without buoyancy) of ~5000lbs at TD
- Remaining over-pull 3000lbs on standard 16klbs cable (8k max safe pull). Consider an electrically releasable weak point.

The conceptual job schematic is shown in Figure 67 below,

[11] Perforating Conveyance Technology Achieves a World Record in Maximizing Operational Efficiency, SPE-194281-MS, Alhadi Zahmuwl et al. (Schlumberger) and Garry Sinclair et al. (Taqa), March 2019

NZT CO_2 Injector - Wireline Perforating

Revision: Rev 1	**Date:** 12 Oct 2020	**Prepared by:** Russ Haley	
CO2 Injector	**Packer Fluid:** Base Oil	**Notes:** All depths approximate	



OD [in]	Nom. ID [in]	L [m]	Top [mTVD SS]	Top [mMD BRT]	Description
			58		5 1/2" Subsea Tubing Hanger
					5 1/2" VAM Top HT Tubing (25% Chrome Super Duplex)
			475		5 1/2" Tubing Isolation / lubricator Valve (TBC for wireline perforating)
			525		5 1/2" SSSV (Alloy 925 or similar)
					5 1/2" VAM Top HT Tubing (25% Chrome Super Duplex)
			957		9 5/8" Casing TOC
			1082		5 1/2" DHPT Dual Gauge Mandrel (tubing and annulus, Alloy 925 or similar)
					DAS / DTS Fibre Bundle
			1107		9 5/8" x 5 1/2" Permanent Packer (Alloy 925 or similar)
			1137		Wireline Entry Guide
			1157		5 1/2" Liner Hanger (Alloy 925 or similar)
			1232		9 5/8" Casing Shoe (flow-wetted 25% Chrome Super Duplex)
			1238		Top Bunter Sandstone
			1318		Top Perforation (standoff from Rot Clay)
					3 3/8" HSD Gun (TBC)
			1418		Bottom Perforation
					5 1/2" VAM Top HT Liner (25% Chrome Super Duplex)
			1512		Top Bunter Shale
			1549		5 1/2" Liner Shoe

Figure 67 Conceptual Wireline Perforating Schematic

7.5.2 Deviated Wells – TCP Shoot and Drop

Although not the current reference case, the potential for drilling from single drill centres in a “clustered” layout must be considered. Such wells would typically be ~60 deg deviation through the reservoir, which means the measured perforating interval is twice that for a vertical well.

This is not ideal for wireline as it cannot be done in one run. The second run would be shot-on balance which is not preferred.

TCP shoot-and-pull is probably the preferred method in such cases; work has not been done on extending TD with a suitable length sump, but it is likely to be feasible as the thickness of the underlying Bunter shale will suffice. A schematic of such an arrangement is shown in Figure 68.

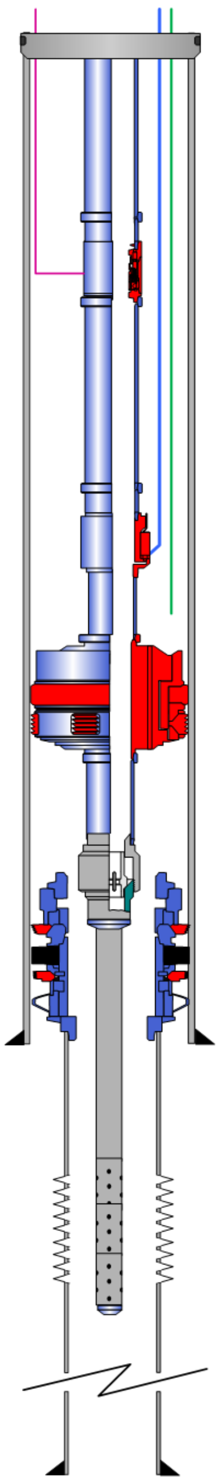
All the advantages of shooting wireline underbalanced in one run can be realised – perforation tunnel clean-up, skin optimisation and operational simplicity.

The main risk would be that the guns did not fall far enough into the sump.

Detailed design on this option will be done in Define, should deviated wells be planned.

NZT CO_2 Injector - TCP Shoot and Drop

Revision:	Rev 1	Date:	12 Oct 2020	Prepared by: Russ Haley
CO2 Injector		Packer Fluid:	Base Oil	Notes: All depths approximate



OD [in]	Nom. ID [in]	L [m]	Top [mTVD SS]	Top [mMD BRT]	Schematic	Description
			58			5 1/2" Subsea Tubing Hanger
						5 1/2" VAM Top HT Tubing (25% Chrome Super Duplex)
			525			5 1/2" SSSV (Alloy 925 or similar)
						5 1/2" VAM Top HT Tubing (25% Chrome Super Duplex)
			957			9 5/8" Casing TOC
			1082			5 1/2" DHPT Dual Gauge Mandrel (tubing and annulus, Alloy 925 or similar)
						DAS / DTS Fibre Bundle
			1107			9 5/8" x 5 1/2" Permanent Packer (Alloy 925 or similar)
			1137			Gun Drop Sub
			1157			5 1/2" Liner Hanger (Alloy 925 or similar)
			1232			9 5/8" Casing Shoe (flow-wetted 25% Chrome Super Duplex)
			1238			Top Bunter Sandstone
			1318			Top Perforation (standoff from Rot Clay)
			1418			Bottom Perforation
						5 1/2" VAM Top HT Liner (25% Chrome Super Duplex)
			1512			Top Bunter Shale 100m Extended Liner
			1649			5 1/2" Liner Shoe

Figure 68 Conceptual TCP Shoot-and-Drop Perforating Schematic

7.5.3 Deviated Wells – TCP Shoot and Pull

TCP shoot-and-pull avoids the need for an extended sump, and is a common method for running long gun strings.

As the Endurance brine will not flow to surface at virgin pressure, the well does not need to be killed after pulling the guns, and so the interval could be shot very simply on-balance with a suitable brine in the well, the guns pulled out and the completion run with open perforations.

The disadvantage of this is that the perforation tunnels will not clean-up properly as they will be shot on-balance, and there is a risk of losses when running the upper completion with surging from the production packer; that said, it is operationally straightforward and does not carry well control risks that would normally occur with a fluid that can flow to surface, and formation damage potential having to pump a kill pill after pulling the guns.

An alternative shoot-and-pull scheme is shown in Figure 69, which allows the interval to be shot underbalanced, permitting perforation tunnel clean-up and skin optimisation.

Detailed design on this option will be done in Define, should deviated wells be planned, but an outline sequence would be:

Guns run under a DST-type packer with a circulation valve in the string
Well full of brine of similar salinity / density to formation (~0.52psi/ft gradient)
Circulate the drill pipe to base oil
Perforate underbalanced
Reverse out base oil to brine
POOH on-balance

NZT CO_2 Injector - TCP Shoot and Pull Run

Revision:	Rev 1	Date:	12 Oct 2020	Prepared by: Russ Haley
CO2 Injector		Packer Fluid:		Notes: All depths approximate

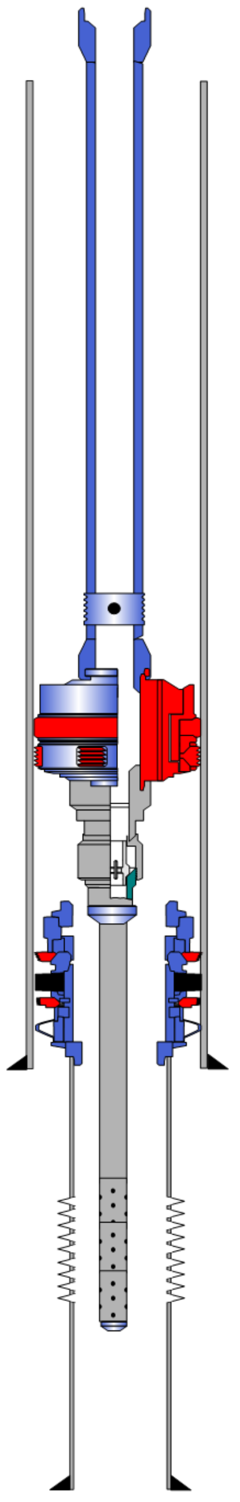
OD [in]	Nom. ID [in]	L [m]	Top [mTVD SS]	Top [mMD BRT]	Schematic	Description
						Drill Pipe Running String
						Circulating Sub
						DST-Type Retrievable Packer
						Firing Head
			1157			5 1/2" Liner Hanger (Alloy 925 or similar)
			1232			9 5/8" Casing Shoe (flow-wetted 25% Chrome Super Duplex)
			1238			Top Bunter Sandstone
			1318			Top Perforation (standoff from Rot Clay)
			1418			Bottom Perforation
						5 1/2" VAM Top HT Liner (25% Chrome Super Duplex)
			1512			Top Bunter Shale
			1549			5 1/2" Liner Shoe

Figure 69 Conceptual TCP Shoot-and-Pull Perforating Schematic

7.5.4 Deviated Wells – Intermediate Completion

An intermediate completion is a further variation on the TCP theme. It would be employed if a detailed evaluation of either shoot-and-drop or shoot-and-pull indicated that these methods were not suitable or preferred.

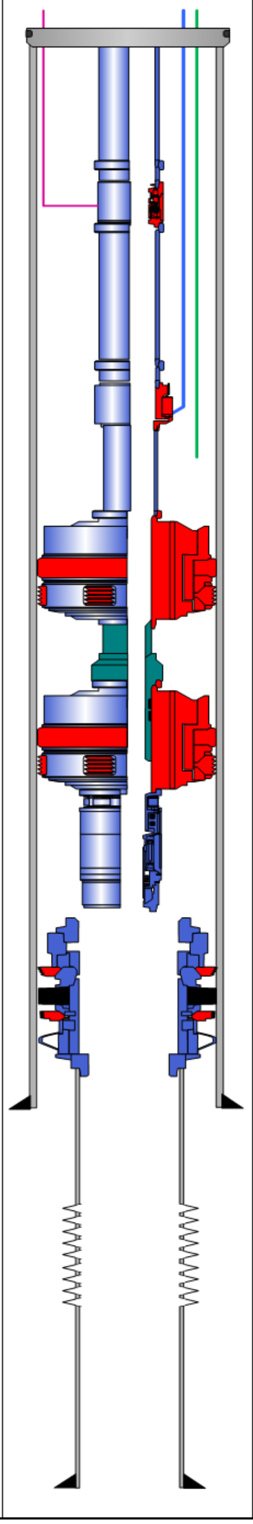
The extra intermediate packer and isolation valve would be run prior to perforating (Figure 71). The guns would be run through the packer and isolation valve, and a shifting tool on the bottom of the TCP string would close the isolation valve as it passed through, thereby isolating the formation from fluids and fluid pressure changes when running the upper completion.

The isolation valve would be opened by pressure-cycles after the well was completed.

This option is more complex, and as the production packer would be around 50-100m higher, it would mean that DAS / DTS would terminate above the Rot Clay.

NZT CO_2 Injector - Intermediate Completion

Revision:	Rev 1	**Date:** 12 Oct 2020	**Prepared by:** Russ Haley	
CO2 Injector		**Packer Fluid:** Base Oil	**Notes:** All depths approximate	



OD [in]	Nom. ID [in]	L [m]	Top [mTVD SS]	Top [mMD BRT]	Schematic	Description
			58			5 1/2" Subsea Tubing Hanger
						5 1/2" VAM Top HT Tubing (25% Chrome Super Duplex)
			525			5 1/2" SSSV (Alloy 925 or similar)
						5 1/2" VAM Top HT Tubing (25% Chrome Super Duplex)
			957			9 5/8" Casing TOC
			1007			5 1/2" DHPT Dual Gauge Mandrel (tubing and annulus, Alloy 925 or similar)
						DAS / DTS Fibre Bundle
			1057			9 5/8" x 5 1/2" Permanent Packer (Alloy 925 or similar)
			1107			Intermediate Completion Permanent Packer with Seal Bore (Alloy 925 or similar)
			1137			Liner Isolation Valve (close on way out of hole)
			1157			5 1/2" Liner Hanger (Alloy 925 or similar)
			1232			9 5/8" Casing Shoe (flow-wetted 25% Chrome Super Duplex)
			1238			Top Bunter Sandstone
			1318			Top Perforation (standoff from Rot Clay)
			1418			Bottom Perforation
						5 1/2" VAM Top HT Liner (25% Chrome Super Duplex)
			1512			Top Bunter Shale
			1549			5 1/2" Liner Shoe

Figure 70 Conceptual TCP / Intermediate Completion Schematic

7.5.5 Deviated Wells – Coiled Tubing

Coiled tubing perforating has not been evaluated at this point, but remains an option to be considered should the need arise.

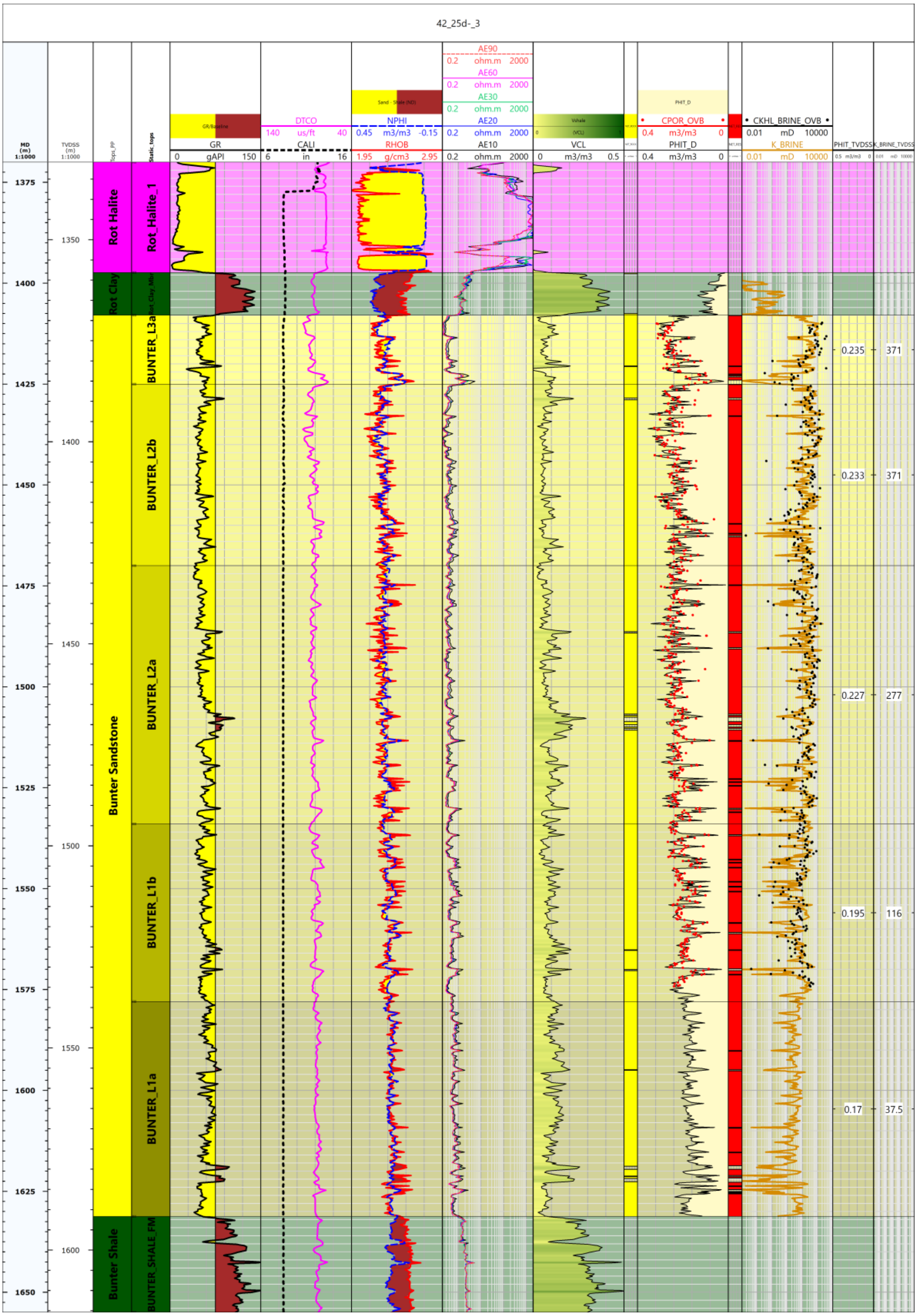


Figure 71 Bunter Composite Log

8.0 Upper Completion Design

8.1 Overview

Referring to Figure 67 and Figure 70, key completion components are:

- 5 ½" 20lb/ft tubing. The current assumption (pending a more detailed metallurgy review) is SM125 25Cr Super Duplex. This metallurgy is resistant to carbonic acid which will form during and after fresh water washing, or when wells are shut-in for an extended period which could lead to formation brine flowing back towards the well bore. VAM Top HT connections have been modelled in the stress analysis, and have been used or planned in other CCUS projects that may see low temperatures; not because they have been qualified at these sub-zero temperatures, but for low-pressure applications with the connection made up at its maximum torque, sealing capacity is likely to be retained. However, a full qualification program for connections will be required in Define, and this has been initiated with bp's tubular and connection specialists.
- Tubing isolation ball valve (e.g. SFIV). This is a lubricator-type valve with two hydraulic lines to operate. The valve would be installed to allow wireline perforating in a single run as the gun length of ~80m is longer than the available height above the tree in 60m of water, even allowing for a few joints of e-line riser above the drill floor. The setting depth be evaluated during Define with regards to J-T effects in a LOPC event (in a similar manner to the SSSV), but as the valve will always be open it will not see the same continuous low temperatures as would be the case with a SSSV with a closed (but leaking) flapper.
- Downhole Pressure / Temperature Gauge mandrel. This is a conventional quartz tubing pressure gauge. An option should be maintained to run a second valve ported to the annulus, either in the same mandrel or separately. The annulus-ported gauge is important for integrity monitoring purposes, and combined with the annuls gauge on the tree, will allow estimation of annulus fluid level and density to distinguish between thermal contraction / expansion and any potential CO2 ingress (e.g. packer leak).
- The production packer is assumed to be a permanent type, with options to hydrostatically set or to run a plug. Elastomers will be specified for low temperature CO2 service.

All engineered equipment is expected to be Alloy 925 or equivalent high nickel content alloy to mitigate corrosion and (by default) any increase in oxygen content in the injection stream specification.

8.2 Operational Considerations - SSSV

Aside from qualifying a SSSV to -78.5 deg C as a “survival” temperature (downhole equipment is typically qualified to in the order of 2 deg C to -7 deg C), consideration should be given to the testing procedure as this has the potential to create low temperatures at the flapper too.

When inflow testing the valve, as the pressure falls below ~70 bar, the tubing contents start to boil off, and once the pressure falls below ~55 bar, the J-T coefficient of CO2 starts to climb rapidly, ultimately resulting in close to 1 deg C drop in temperature for every 1 bar bled off (in the absence of an external heat source). This means that the inflow test will have to be carried out over an extended period to allow the surrounding overburden to act as a heat source.

Furthermore, in the case of a flapper leak (within or without of API 14 limits, which one must assume will occur at some point in the well’s life), a localised cold spot will develop around the leak which will generate a temperature of -78.5 deg C (sublimation temperature of CO2 at 1 atmosphere pressure). As the qualification of the valve may not allow temperatures this low (aside from in a “survival” case rather than subsequent normal operation), the target bleed-off pressure and test duration will have to be developed in detail to stay within the valve’s specification. This will be considered in Define once the qualification characteristics of potential valves are better understood.

9.0 Subsea

9.1 System Architecture

The recommended project concept is a distributed subsea injection system comprising five dedicated CO_2 injection wells and a monitoring / observation well that could be hooked up to the injection flowline and used as a 6th injector (**Figure 72**).

There are two options for the observation well location – Option 1 in the east provides for some reservoir appraisal and a later detection of the CO_2 pressure front, whereas Option 2 in the west on the main crest of the structure gives a more direct measurement of crestal pressure (cap rock limits) but future expansion to the east would not have any appraisal. The location of this well will be determined in Define.

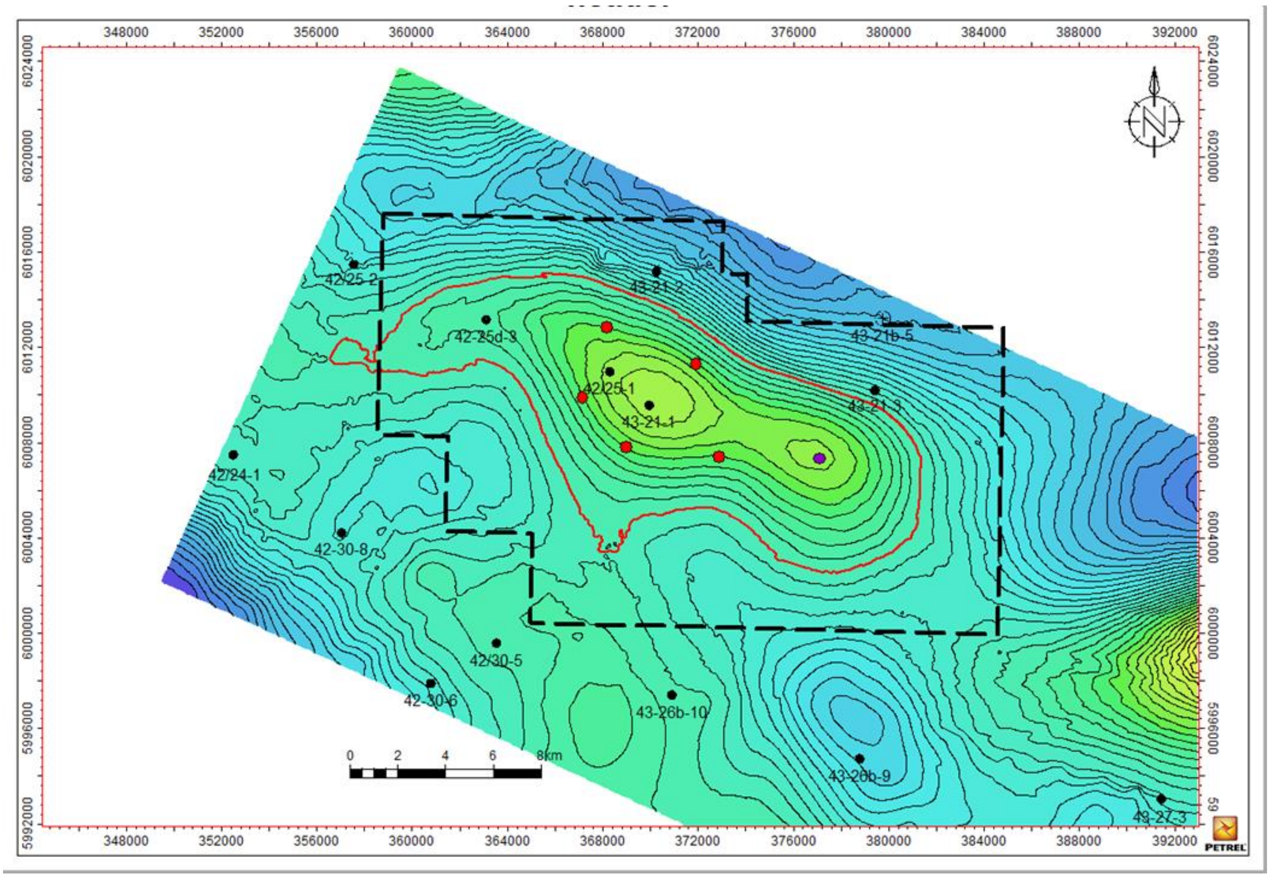


Figure 72 Distributed Subsea Layout

Figure 73 shows the subsea equipment schematic with pipeline and umbilical connections. The xmas tree type has not been selected at this stage – a vertical "tree on mudline" system is preferred to allow subsea wells to be drilled from a jack-up more simply, but the qualification level of such a tree and its ability to incorporate fibre optic feed throughs may need further evaluation.

The subsea tree, running tooling and completion landing string will be handled by bp's Central Subsea Solutions group during tendering.

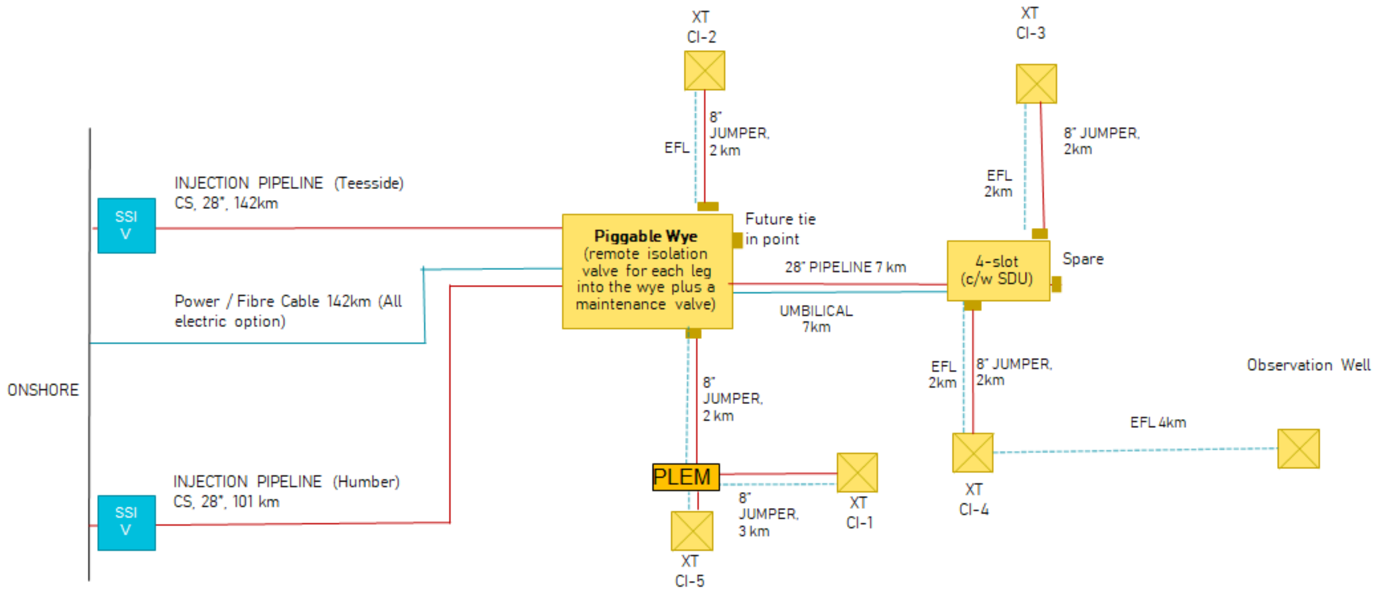


Figure 73 Distributed Subsea Equipment

9.2 Qualification Considerations – Wellheads and Trees

Standard subsea wellheads and trees are specified as for service down to -29 deg C. Below that, the next restriction is elastomer glass transition temperature; however as NZT/NEP shut-in pressure is relatively low, elastomeric glass transition / explosive decomposition will be less of an issue compared to other hydrocarbon gas projects.

Chokes are typically qualified to -46 deg C for JT effects in gas production, but for a CO2 injector, flow is reversed so the tree and downhole end of the choke will see the lower temperatures through conduction and cold fluid transport.

For normal operation, these temperature specifications satisfy NZT/NEP requirements, but it may be necessary to do some additional qualification to cope with survivability in a LOPC situation as described for well components previously.

API 6A allows equipment to be qualified to -75 deg F / -60 deg C, which satisfies the -55 deg C minimum temperature that would be seen in such a loss of primary containment.

Tree valve operating frequency may also need looking at – typically subsea valve actuators are qualified for 600 cycles for BP (API 17D 200, PR2 +200, endurance +200 hyperbaric), but for dispatchable operation with near daily shut-ins possible for the carbon capture system, further qualification may be needed in addition to phasing / alternating which wells or valves are used to close in for each dispatchable cycle.

For fibre optics (DAS, DTS), although FO tree penetrators are theoretically commercially available for subsea trees, BP are running a qualification program internally on the Atlantis field in GoM. The results are being followed with reference to NZT/NEP.

9.3 Wash Water Injection System

Section 0 described why fresh-water washing is needed to dissolve any near-wellbore halite precipitation. The operation to do this is similar to a scale squeeze, with ~2000 bbl of fresh water pumped per well. Initial flow assurance work indicates the need for a MEG buffer either side of the water flush, with MEG injection continuing as the well is started up to prevent hydrates.

Currently the assumption is that the treatment will be pumped from a vessel (rather than a fresh water pipeline), and so the vessel needs to be able to handle the MEG and fresh water volumes, in addition to the pumping equipment, and needs to remain on-station as CO2 injection is re-started.

The wash water will need inhibition for scale, hydrates, bacterial growth and corrosion as a minimum

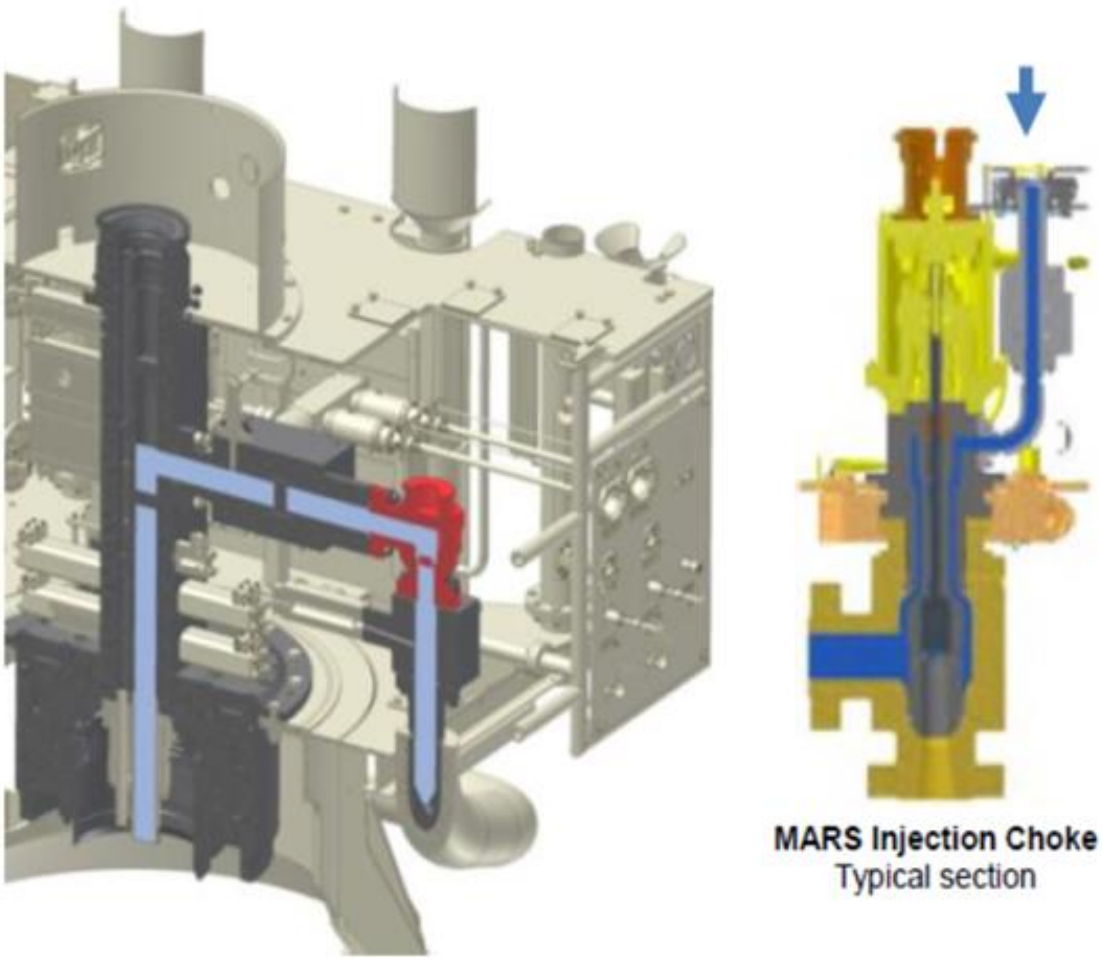


Figure 74 MARS Choke Insert for Water Wash Access

The connection to the well has not been designed in any detail, but two options are well-used in the industry and have been by BP.

9.3.1 OneSubsea MARS

The MARS injection choke replaces the choke on the tree, and allows a vessel to run a hose / riser connection to an injection skid and thence to the tree. The treatment can be pumped and the vessel then moves on to the next well.

Although no detailed work has been done on this job, it can be done from a variety of specialist vessels or vessels of opportunity, and has even been done from a supply boat in west Africa. The water wash may even be possible to combine with regular surveillance operations from a LWIV depending on tank capacity.

The fresh water wash will be pumped at up to 40m3/hr (~4.2bbl/min), which is well within the capabilities of the MARS system (**Figure 75** and **Figure 76**).

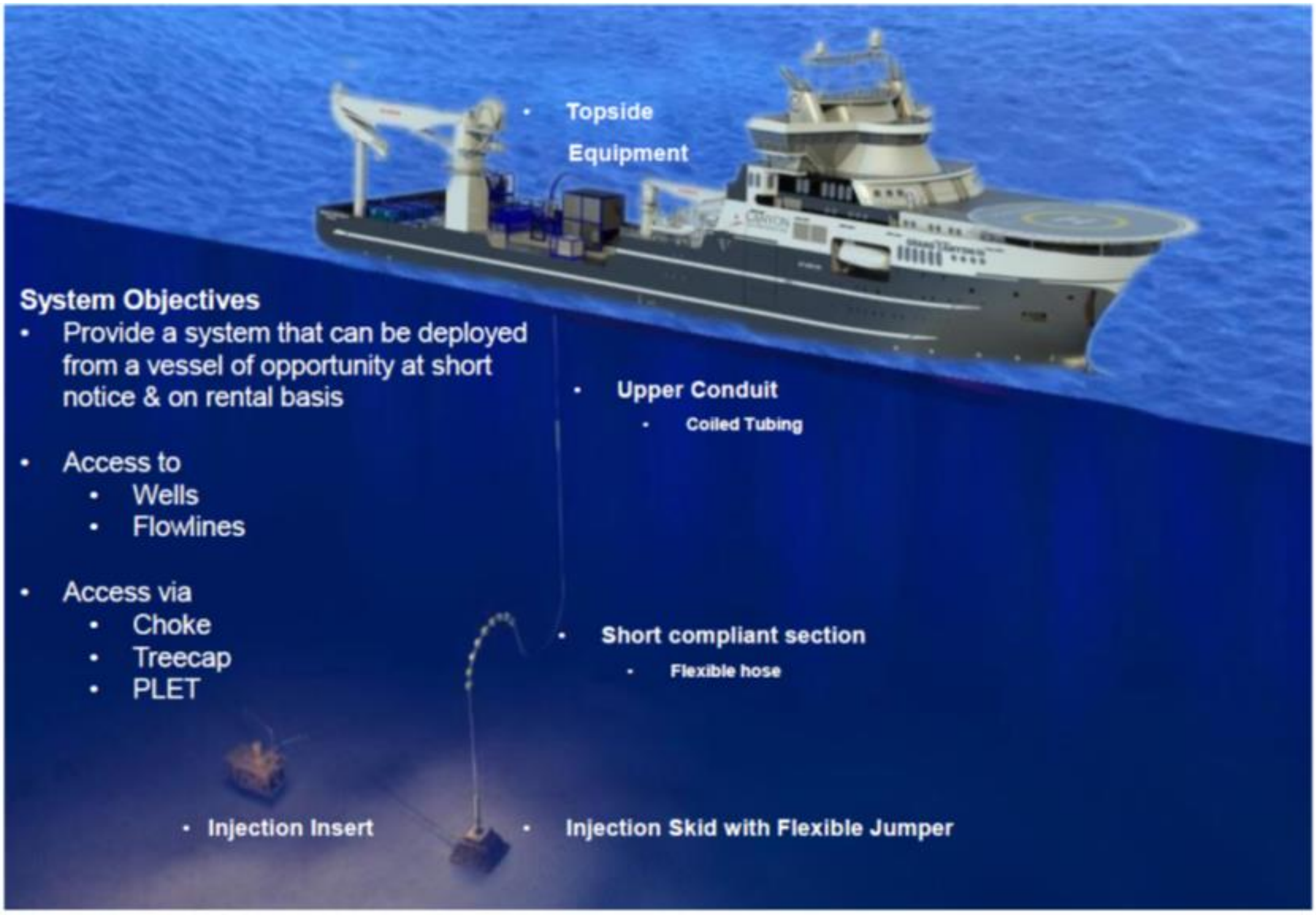
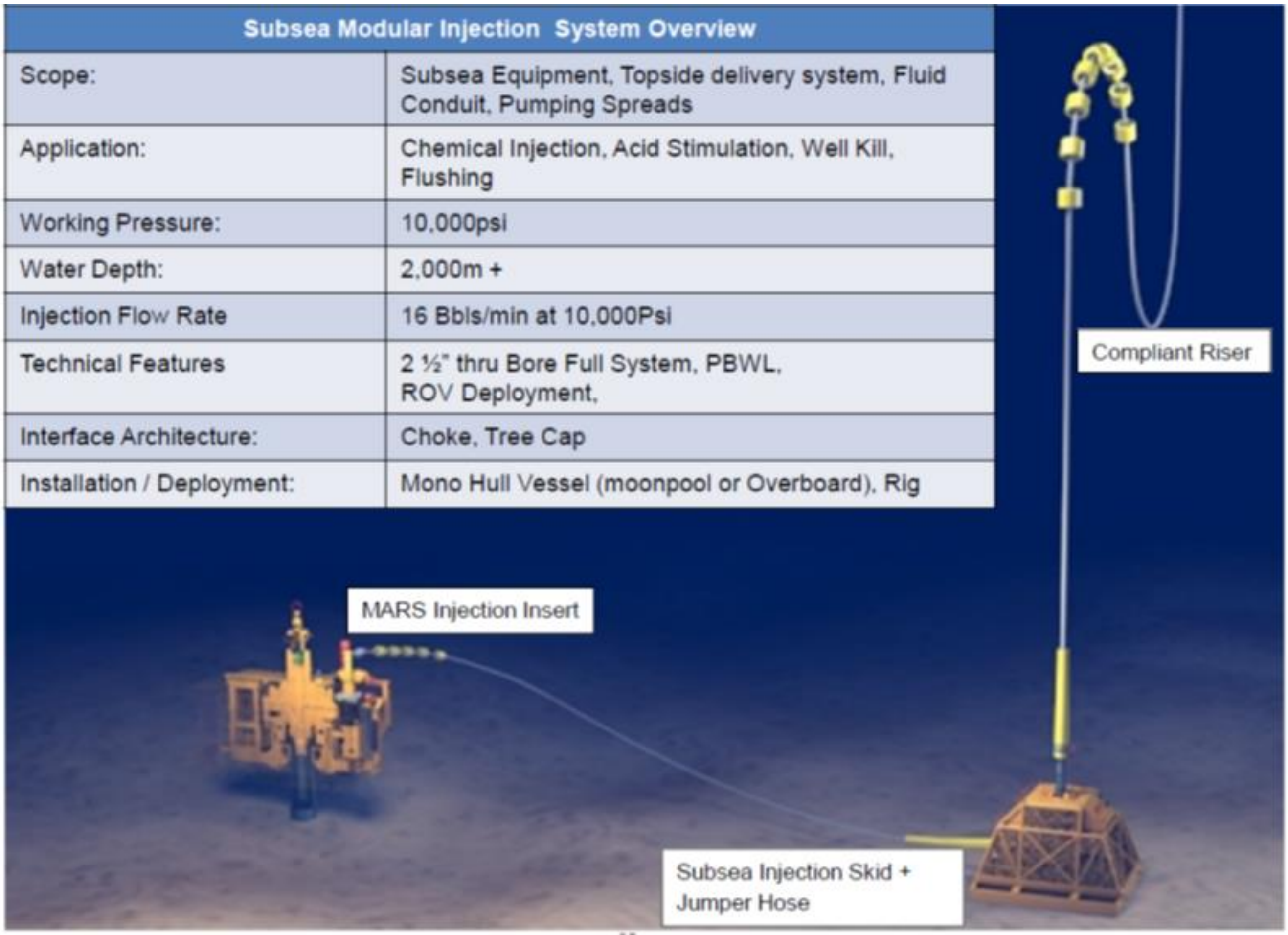


Figure 75 MARS System Operation from Vessel



Subsea Modular Injection System Overview	
Scope:	Subsea Equipment, Topside delivery system, Fluid Conduit, Pumping Spreads
Application:	Chemical Injection, Acid Stimulation, Well Kill, Flushing
Working Pressure:	10,000psi
Water Depth:	2,000m +
Injection Flow Rate	16 Bbls/min at 10,000Psi
Technical Features	2 ½" thru Bore Full System, PBWL, ROV Deployment,
Interface Architecture:	Choke, Tree Cap
Installation / Deployment:	Mono Hull Vessel (moonpool or Overboard), Rig

Figure 76 MARS System Operation Close-Up

9.3.2 Enpro Flow Modular Flow Access System

Enpro offer a similar system to OneSubsea, but in a modular form that can be installed on any vendor's tree or manifold (**Figure 77**).

Although installation on a manifold may be the simplest mechanically, the length of flowline to each well will need to be considered as any water and MEG may get strung-out over longer distances and lead to an ineffective treatment. The flow assurance work to address this will be completed in Define, but at this stage the assumption is for a tree-mounted system which has been factored into OPEX.

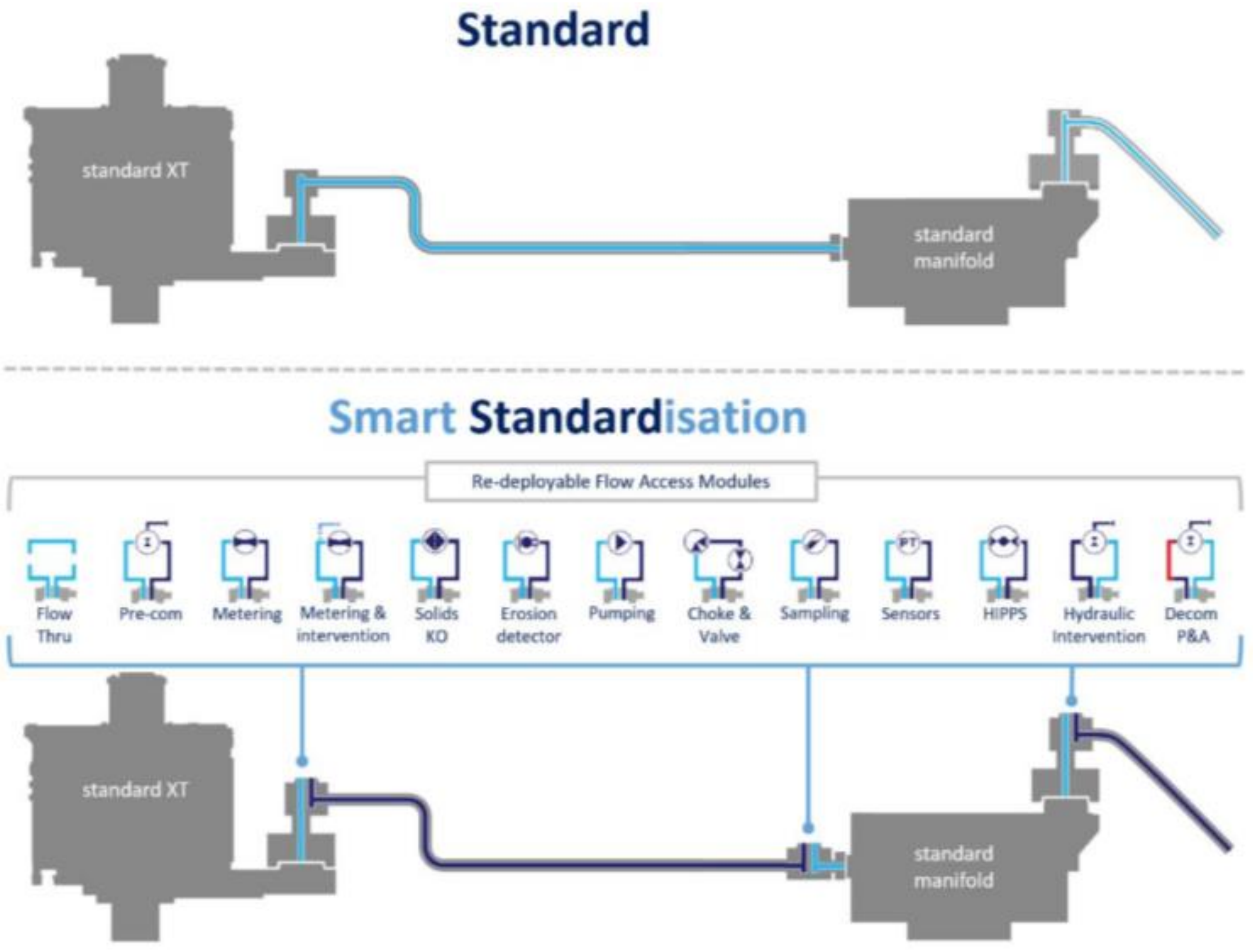


Figure 77 ENPRO External Fluid Access System (manifold or tree)

10.0 Tubing Stress Analysis Summary

10.1 Summary

This analysis considers the upper completion only, from packer to tubing hanger, and was done for a dry tree development. Since the work was done, the project has moved towards a subsea development, and the stress analysis will be revisited in Define.

The lower completion will be a simple cased and perforated liner, and there will be no direct connection between the upper and lower completions.

- The load cases conform to BP Practice 100202 (GP10-01), and that the analysis shows the proposed design is fit for purpose
- The load case methodology follows BP Tubing Design Guide 100485
- Additionally, the load cases are conservative in that they consider maximum differential pressures (e.g. reservoir pressure vs full evacuation)
- Methanol / MEG dead-head pressure into an open annulus was considered at the 10,000 psi rating of the tree

10.2 Introduction

The objective of the tubing design is to inject CO_2 a rate of 1 MTPA (equivalent to approximately 52 mmscf/d as a gas at STP, or ~19,000 bbl/d as a liquid). To cover situations where the rate is increased to make up for poor injectivity elsewhere or well losses, 2 MTPA peak will be assumed.

10.3 Design Input Data

10.3.1 Safety Factors

Conditions	Burst	Collapse	Axial (Tension)	Axial (Compress.)	Triaxial
Tubing (Test)	1.1	1.1	1.1	1.1	1.1
Tubing (Service)	1.25	1.1	1.33	1.33	1.25
Connections (Test)	1.1	1.1	1.1	1.0	1.0
Connections (Service)	1.25	1.1	1.33	1.0	1.0

Table 46 BP Minimum Acceptable Tubing Stress Analysis Design Factors

10.3.2 Well Trajectory

At the time of writing, target locations are not available. This table represents a simplified trajectory based on the "W1" well path from the White Rose project wells BoD12.

Data-Entry Mode	MD (m)	INC (°)	AZ (°)	TVD (m)	DLS (°/30m)	Max DLS (°/30m)	Vsection (m)	Departure (m)
MD-INC-AZ	0.0	0.0	0.0	0.0			0.00	0.00
MD-TVD	35.00			35.00		0.00	0.00	0.00
MD-TVD	128.00			128.00		3.00	0.00	0.00
MD-TVD	682.00			631.00		3.00	232.18	232.18
MD-TVD	738.00			667.00		3.00	275.07	275.07
MD-TVD	948.00			788.00		3.00	446.71	446.71
MD-TVD	2294.00			1560.00		3.00	1549.31	1549.31

Table 47 Simplified Well Trajectory

[12] K38 Subsurface Well Report, National Grid Carbon Limited White Rose Carbon Capture and Storage Project January 2016

10.3.3 Well Schematic

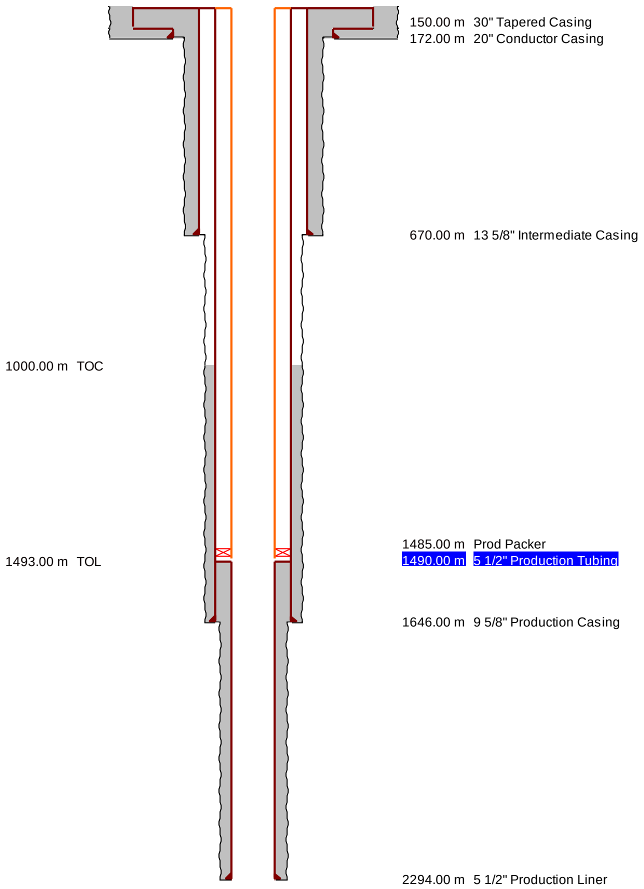


Figure 78 Well Schematic (RKB 35m)

10.3.4 Casing and Tubing Configuration

Name	Type	OD (ins)	MD (m)			Hole Size (ins)	Annulus Fluid
			Hanger	TOC	Base		
Conductor	Casing	30.000	95.00	95.00	172.00	36.000	Seawater
Intermediate	Casing	13 5/8	96.00	96.00	670.00	17 ½	Mud 1.33 S.G.
Production	Casing	9 5/8	97.00	1000.00	1646.00	12 ¼	Mud 1.42 SG
Production	Liner	7.000	1493.00	1493.00	2294.00	8 ½	Mud 1.46 SG
Production	Tubing	5 ½	98.00		1490.00		Seawater

Table 48 Simplified Casing and Tubing Configuration

MD (m)		Pipe			Connection		
Top	Base	OD (ins)	Weight	Grade	Name	Grade	OD (ins)
98.0	1490.0	5 ½"	20	SM25CR-125 (derated)	Vam Top HT	SM25CR-125 (derated)	6.050"

Table 49 Tubing (see Section 0)

10.3.5 Tubing Properties

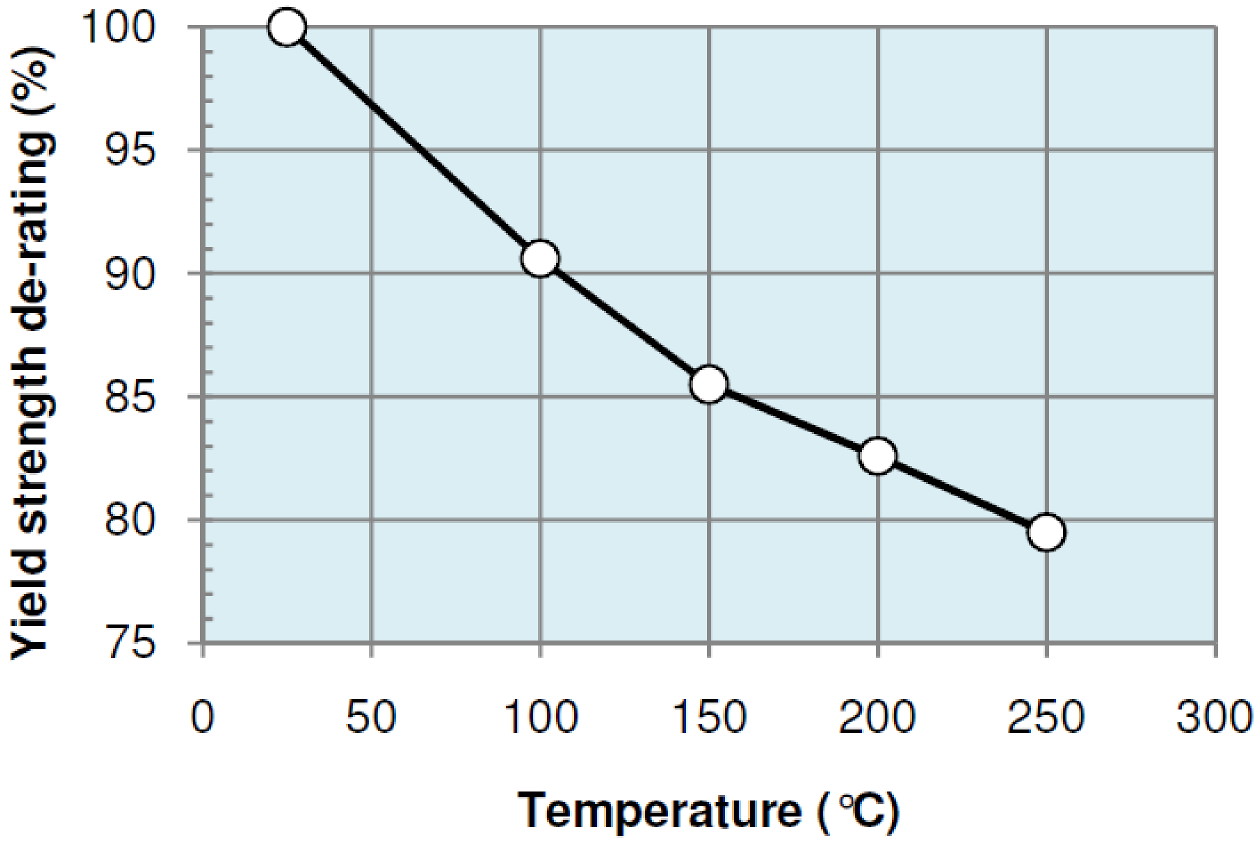


Figure 79 Sumitomo SM25CR-125 Yield Strength Deration with Temperature

Parameter	25 degC	100 degC
Tubing Size (in.)	5 ½”	5 ½”
Weight (lb/ft)	20	20
Material / Grade	SM25CR-125	SM25CR-125
Pipe ID (in.)	4.778”	4.778”
Drift (in.)	4.653”	4.653”
Wall Thickness Tolerance (%)	12.5	12.5
Burst (psi)	16,660	De-rate as per WellCat
Collapse (psi)	17,392	De-rate as per WellCat
Tensile Yield (lbs)	826,417	De-rate as per WellCat
Yield Strength (ksi)	125,000	113,750
Ultimate Tensile Strength (ksi)	130,000	117,780
Young’s Modulus (GPa)	202	197
Yield Strength Deration in Compression	80%	80%
Poisson’s Ratio	0.22	0.22
Coeff. of Thermal Expansion (10-6 /degC)	-	13.1
Density (Kg/m3)	7785	7760
Thermal Conductivity (W/m/degC)	12.4	13.7
Specific Heat Capacity (J/Kg/degC)	446	464
Radial Anisotropy (%)	100	100
Hoop / Circumferential Anisotropy (%)	100	100

Table 50 Tubing Material Properties (SM25CR-125)

10.3.6 Compressive Yield Anisotropy

Cold-drawn duplex stainless steel exhibits compressive yield strength that is lower than the tensile yield strength. NSSMC reports 80% compression rating for 25%Cr materials, which is 100 ksi for SM25CR-125.

WellCat cannot handle different tension and compression yield strengths, and so a “de-rated” SM25CR-125 grade has been set-up with a yield strength of 100ksi – i.e. the pipe has been de-rated in tension as well as compression.

10.3.7 Connection Performance Properties

VAM Top HT connections are assumed to have 100% and 80% of pipe tensile yield in tension and compression respectively. All other properties are as per their respective pipe sizes for the same grade material. Note that the compressive strength of the connection is 80% of yield in common with the deration for anisotropy, and as the connection in the analysis uses the same 80% de-rated material grade, no further reduction in compressive strength has been made.

10.4 Reservoir Properties and Well Data

10.4.1 Initial Temperature

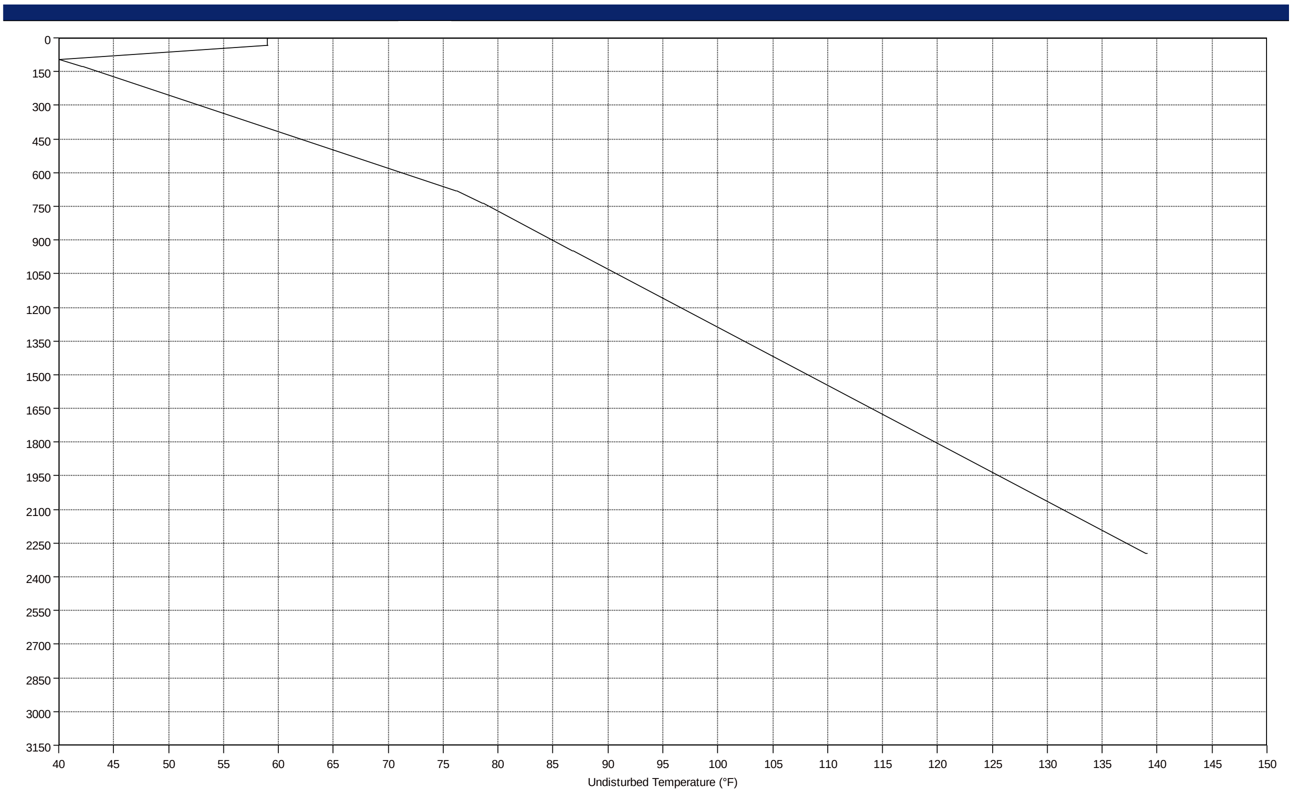


Figure 80 Undisturbed Temperature

10.4.2 Reservoir Fluids

Parameter	Lower Cenomanian
Reservoir rock	Sandstone
Reservoir type	Brine (250,000 ppm)
Reservoir reference depth (m TVDss)	1300 m TVDSS
Reservoir top depth (m TVDss)	1214 m TVDSS
Reservoir bottom depth (m TVDss)	1488 m TVDSS
Initial reservoir pressure at reference depth	140 bar (2030 psi)
Maximum (final) reservoir pressure at reference depth	200 bar (2900 psi)
Shut in wellhead pressure (final pressure)	1585 psi at the tree
Temperature at reference depth	57 deg C

Table 51 Subsurface Parameters

Although the injected stream will included impurities which will affect the phase envelope, for the purposes of this analysis, 100% CO2 is assumed.

Component	Composition (mol%)
CO2	100

Table 52 Injected Fluid Data

10.4.3 Reservoir Pressure and Injection Pressure

The initial reservoir pressure 140bar (2030 psi) at a reference depth of 1300 m TVD SS. As injection progresses, the reservoir will pressure up to an estimated maximum of 200 bar (2900 psi) to stay within cap rock fracture limits.

Under injection conditions, the annulus would contract and pull a vacuum as cold CO2 is injected from the subsea pipeline.

The tubing leak cases assume an unexpanded gas bubble at prevailing reservoir pressure at the top of the annulus.

10.4.4 Initial Conditions and Completion Running Fluid

The completion will be run in ~11.3 ppg brine, and the tubing displaced to seawater before the packer is set.

10.4.5 Packer Fluid

The annulus will be left completed with base oil. This is to avoid formation of carbonic acid or hydrates if CO_2 were to leak from the tubing or below the packer.

10.4.6 Other Design Input Data

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10.5 Stress Analysis Model and Key Assumptions

10.5.1 Analysis Package

The analysis was done using Landmark's WellCat package, Version EDM 5000.15.1.21.

10.5.2 Packers

The model assumes a simple tailpipe below the packer with no interface with the lower completion. The packer is set hydrostatically with 2500 psi applied pressure. There is no PBR or expansion joint in the string.

10.6 Design Load Cases

10.6.1 Transient Load Cases

A full suite of transient load cases has not been evaluated yet as the design transitions from its original dry tree to a subsea system (for example, start-up following a water wash). This will be done in FEED / Define.

10.6.2 Drag Modelling

No drag modelling has been carried out in this analysis. It is recognised that setting the packer hydrostatically would lock in any drag forces which will be larger (compressive) as the step-out increases. It is assumed here that these forces are not significant but will be estimated in subsequent analyses.

10.6.3 Annulus Thermal Expansion and Wellhead Growth

The annulus fluid will contract on injection due as the CO_2 from the pipeline will be close to seabed ambient temperature. Wellhead growth has not been modelled at this stage.

10.6.4 PROD Operations

Name and Description	Type	Production Conditions	Wellhead Pressure (psi)	Pressure at Perfs (psi)	Tubing Correlation	Wellhead Annulus Pressure (psi)	Annulus Gradient
Injection 57mmscf/d	SS Injection	57 mmscf/d (1 MTPA) Injection	1637	2900	Duns and Ros	0	Base Oil
Injection 114mmscf/d	SS Injection	114 mmscf/d (2 MTPA) Injection	2165	2900	Duns and Ros	0	Base Oil
Transient Shut-In	Shut-In	1 minute Following Injection 114mmscf/d (final Pr)	1448	2900	Duns and Ros	0	Base Oil
Cold Long Term Shut-In	Shut-In	1 year	1493	2900	Duns and Ros	0	Base Oil
Transient Shut-In with Tubing Leak	Shut-In	1 minute Following Injection 114mmscf/d (final Pr)	1448	2900	Duns and Ros	2900	Base Oil
Bullhead Kill End	Transient Injection	240 gpm 12ppg brine for 10 hours	Vacuum to 146m MD	2900	Duns and Ros	0	Base Oil

Table 53 PROD Operations Input Data

10.6.5 TUBE Loads

Table below shows a summary of the load-case construction.

Number	Description	PROD Link	Tubing Pressure Profile	Pressure at Perfs (psi)	Annulus Pressure Profile	Annulus Temperature Profile
R1	Running Tubing	n/a	11.3 ppg brine	n/a	11.3 ppg brine	Geothermal
R2	Overpull 100k lbs	n/a	11.3 ppg brine	n/a	11.3 ppg brine	Geothermal
R3	Pressure Test Tubing	n/a	3500psi over sea water. Plug at 1480m MD	n/a	0 psi over base oil	Geothermal
R4	Pressure Test Annulus	n/a	0 psi over sea water	n/a	3500 psi over base oil	Geothermal
R5	Inflow Test SSSV	n/a	Sea water, 1000 psi under closed SSSV at 500 m MD	n/a	0 psi over base oil	Geothermal
P1	Injection 114mmscf/d	Injection 114mmscf/d	Injected CO2 gradient Duns and Ros correlation	2900 psi	0 psi over base oil	Injection gradient
P2	Injection 57mmscf/d	Injection 57mmscf/d	Injected CO2 gradient Duns and Ros correlation	2900 psi	0 psi over base oil	Injection gradient
P5	Transient Shut-In	Transient Shut-In	Shut-in CO2 gradient	2900 psi	0 psi over base oil	Injection gradient
P6	Long Term Shut-In	Long Term Shut-In	Shut-in CO2 gradient	2900 psi	0 psi over base oil	Geothermal
P7	Bullhead Kill Start	Long Term Shut-In	3000 psi pump pressure over shut-in CO2 gradient	n/a	0 psi over base oil	Geothermal

P8	Bullhead Kill End	Bullhead Kill End	0 psi over 1.74sg brine	2900 psi	0 psi over base oil	Geothermal
P9	Tubing Evacuation 3000 psi Annulus	Transient Shut-In	Evacuated	2900	3000 psi over base oil	Injection gradient
P11	Tubing Leak Below SSSV	Long Term Shut-In with Tubing Leak	2050 psi below SSSV, zero psi above it	2900 psi	~3000 psi over base oil	Geothermal
P13	Methanol leak into 'A' annulus	Transient Shut-In	Shut-in CO2 gradient	2900 psi	10,000 psi over base oil	Injection gradient

Table 54 TUBE Operations Input Data

10.7 Tubing Results and Discussion

Table below shows the minimum safety factors for all load cases.

Case	Description	Minimum Safety Factor			
		Triaxial	Burst	Collapse	Axial
R1	Running Tubing	5.453	100+	6.201	5.509
R2	Overpull 100k lbs	3.323	100+	3.585	3.344
R3	Pressure Test Tubing	3.016	2.616	100+	5.209
R4	Pressure Test Annulus	3.246	100+	2.963	6.719
R5	Inflow Test SSSV	8.039	7.588	11.546	8.568
P1	Injection 114mmscf/d	4.936	4.868	100+	5.404
P2	Injection 57mmscf/d	4.667	6.267	100+	5.683
P5	Transient Shut-In	5.825	6.778	100+	5.643
P6	Long Term Shut-In	6.363	6.441	100+	6.437
P7	Bullhead Kill Start	4.013	3.505	100+	5.526
P8	Bullhead Kill End	5.895	8.922	7.108	5.895
P9	Tubing Evacuation 3000 psi Annulus	3.026	100+	2.439	8.249
P11	Tubing Leak Below SSSV	3.707	100+	3.359	11.159
P13	Methanol leak into ‘A’ annulus	1.430	100+	1.187	3.970

Table 55 TUBE Minimum Safety Factors

All design factors exceed the minimum safety factors shown in Table .

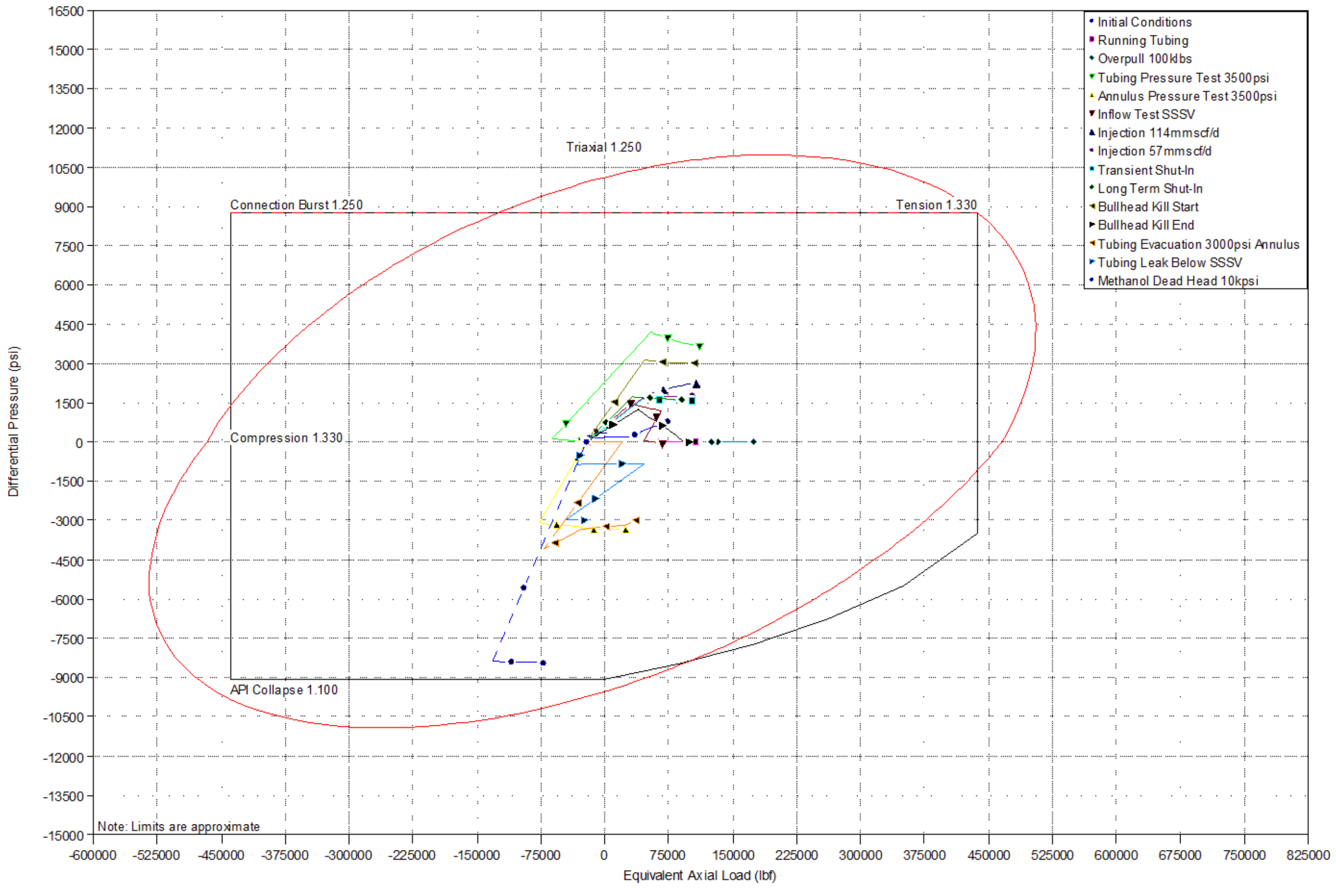


Figure 81 Design Limits Plot

10.8 Completion Equipment Performance

10.8.1 Production Packer

The completion equipment vendor has not been selected yet. Packer loads are shown below in **Figure 82**, plotted inside the performance envelope of an example packer (in this case a Halliburton 9 5/8” 15kpsi S13Cr110 HPS permanent packer). This does not constitute a recommendation to use this packer or any other. All load cases fall within the envelope.

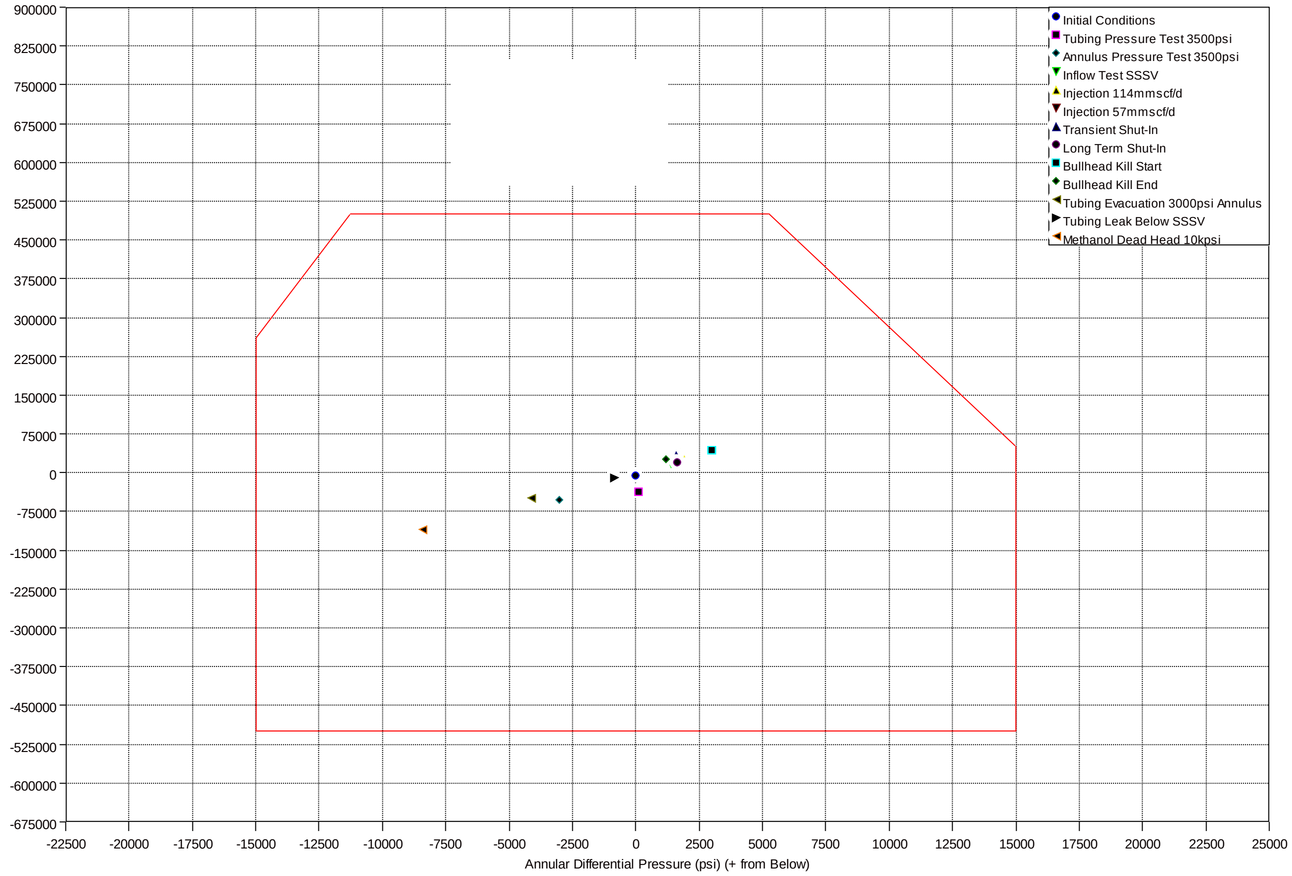


Figure 82 Packer Envelope for Example Packer

Load Case	Tubing-to-Packer Force (lbf)	Axial Load		Annulus Pressure		Temp (deg C)	Packer-to-Casing Force (lbf)
		Above (lbf)	Below (lbf)	Above (psi)	Below (psi)		
Initial Conditions	5828	-12731	-6905	1213.66	1213.69	107.61	5828
Running Tubing	N/A	31746	31743	2110.74	2110.81	107.61	N/A
Overpull 100klbs	N/A	87855	87853	2110.74	2110.81	107.61	N/A
Tubing Pressure Test 3500psi	37439	-44341	-6905	1105.07	1213.69	107.61	33805
Annulus Pressure Test 3500psi	53012	-62210	-9200	4605.07	1607.47	107.61	153297
Inflow Test SSSV	-16890	2027	-14866	1188.97	2579.72	100.82	-63417

Injection 114mmscf/d	-37908	21400	-16510	1109.85	2863.56	70.20	-96578
Injection 57mmscf/d	-31996	16104	-15894	1109.28	2756.35	73.20	-87098
Transient Shut-In	-32495	16825	-15673	1108.99	2717.79	70.40	-86317
Long Term Shut-In	-19875	4092	-15786	1101.05	2737.54	100.82	-74624
Bullhead Kill Start	-42785	19013	-23774	1101.05	4108.16	100.82	-143387
Bullhead Kill End	-25862	12408	-13457	1111.24	2334.10	63.50	-66773
Tubing Evacuation 3000psi Annulus	49829	-49651	176	4108.99	0.00	70.40	187295
Tubing Leak Below SSSV	10515	-29367	-18854	4101.35	3264.02	103.21	38528
Methanol Dead Head 10kpsi	110115	-125781	-15669	11109.85	2717.16	70.40	390892

Figure 83 Packer Forces

10.8.2 SSSV

The completion equipment vendor has not been selected yet. The SSSV will be a 5 ½" valve, but has not been modelled explicitly in this analysis.

10.8.3 Tubing Movement / PBR Shear Ratings

There is no PBR or expansion joint in the completion design

10.8.4 Tubing Hanger

The tree vendor and tree type has not been selected yet. The tree SoR shall specify that the tubing hanger material strength, thread and lock-down ratings are all the same as or exceed that of 5 ½" 20lb/ft 125ksi VAM Top HT connections.

11.0 Operational Considerations

11.1 Data Acquisition

The data acquisition plan has yet to be finalized, this document provides a best estimate at this point in time. The information here will be superseded by the individual well SOR for data collected during the drilling and completions phase and by the “MMV plan” for data collected during well operations.

Attention is drawn to the requirement for a pilot hole (possibly 12-1/4” which would be subsequently opened to 17-1/2”) to realise the data acquisition objectives in the upper section of the observation well.

Overburden					
Section	Logging Data	Main Objectives	Wells	Comments	Conveyance
Upper section	Gamma Ray, Resistivity, Sonic (compressional)	Seismic well tie	All		LWD preferred
	Density, Sonic (compressional and shear), oriented calipers	Seismic well tie	Single crestal well	Expectation that a pilot hole will be needed to acquire good quality data	LWD or WL
	Vertical Seismic profile	Seismic well tie	One	May not be necessary if DAS technology can provide a suitable alternative	WL only
Intermediate section	Gamma Ray, Resistivity	Casing point selection	All		LWD only
	Density, Sonic (compressional and shear)	Seismic well tie	All		LWD or WL
	Cross dipole sonic, calipers	Geomechanics	Single crestal well		WL only
	Image log	Looking for evidence of fracturing or faulting (primarily in halite)	Single crestal well	Latest generation tool required for high quality image	LWD or WL
	Rotary sidewall cores	Analysis of rot halite (assessing the heterogeneity of the halite)	Single crestal well	Over Rot halite only. Whole core would also satisfy objectives	WL only
	Vertical seismic profile (VSP)	Seismic well tie	One or two	May not be necessary if DAS technology can provide a suitable alternative	WL only

Table 56 Data Acquisition - Overburden

Reservoir (Bunter Sand)				
Logging Data	Main Objectives	Wells	Comments	Conveyance
Gamma Ray, Resistivity, Density, Neutron	Basic reservoir characterisation, seismic well tie	All		LWD or WL
Sonic (compressional, shear), oriented calipers	Seismic well tie, reservoir characterisation	All		WL preferred
Nuclear Magnetic resonance	Assessing vertical variability in rock quality to aid perforation selection	All	Assumes cased and perforated completion	WL preferred
Density spectroscopy	Advanced reservoir characterisation (variations in matrix density)	All		LWD or WL
Formation pressures	Assessing original pressure in wells pre-injection Assessing variation in salinity across the structure	All		LWD or WL
Formation fluid samples	Assessing variation in salinity across the structure	Two or three	The number of wells will depend on whether the clustered or dispersed option is selected for well location	WL only
High resolution image logs	Sedimentology characterisation	Three	Latest generation resistivity tool required for high quality image	WL only
Vertical seismic profile (VSP)	Seismic well tie	One or two	May not be necessary if DAS technology can provide a suitable alternative	WL only

Table 57 Data Acquisition - Reservoir

<table>
<tr><th colspan="3">Wole Core Data</th></tr>
<tr><th>Formation</th><th>Main Objectives</th><th>Wells</th></tr>
<tr><td>Rot Clay</td><td>Additional geomechanics measurements

Gain measurements at the crest of the structure and inform properties relative to the flank

Determination of shale properties

42/25d-3 core was incorrectly cleaned and did not achieve this objective</td><td rowspan="2">One in a clustered development, two in a distributed development</td></tr>
<tr><td>Bunter Sandstone</td><td>Geological description

Lower part of the Bunter sandstone has not been cored in the field

No modern core is present in the proposed development area – risk that geology is different to the down flank cored location

Static property calibration

Test the assumption that properties derived from the cored well on the Western flank are applicable to the entire structure

Dynamic property calibration

Improve understanding of vertical and lateral connectivity – integrate with injection data</td></tr>
</table>

Table 58 Data Acquisition – Core

Dedicated Geomechanics Data				
Formation	Data	Objective	Wells	Comments
Rot Halite	FPIT	Calibration of geomechanics model at structure crest	Single crestal well	Test expected to be carried out in middle of halite, to approximately overburden stress. Will require a dedicated tool to be run
Rot Clay	FPIT	Calibration of geomechanics model at structure crest	Single crestal well	Depending on well design, could be combined with standard FIT at start of hole section

Table 59 Data Acquisition - Geomechanics

Cased Hole Data (well construction)			
Section	Logging Data	Main Objectives	Wells
Upper casing (assumed 13 3/8")	CBL/VDL and ultrasonic (USIT etc.)	To determine quality of bond between casing and cement. This will provide assurance on future integrity or assist in developing remediation programs	All N.B. This data is primarily to address regulatory concerns
Intermediate casing	CBL/VDL and ultrasonic (USIT etc.)	To determine quality of bond between casing and cement. This will provide assurance on future integrity or assist in developing remediation programs	All
Production liner	CBL/VDL and ultrasonic (USIT etc.)	To determine quality of bond between casing and cement. This will provide assurance on future integrity or assist in developing remediation programs	All
	Pulse neutron log	Baseline saturation log, with well in initial conditions. Characterizes the in-situ brine system, which will make monitoring CO2 migration easier significantly more accurate for future surveillance	1

Table 60 Data Acquisition – Cased Hole

Injectivity Test and Interference Testing		
Formation	Main objectives	Wells
Bunter sandstone (completion interval TBC)	Determination of injectivity for each well with initial fresh-water pre-flush with fresh water in each CO2 injector (CI1, CI2, CI3, and CI4, CI5) Limited volumes (up to 6000 barrels per well) can be brought to the rig via a supply boat for post-completion surge (bullhead into subsea well head)	All injectors
Bunter sandstone (completion interval TBC)	Extended injectivity test could be carried out in OE1 (crestal observation well) to perform inter-well interference test between crestal well (CI5) and downdip completed CO2 injectors Larger fresh-water volumes would be required (of the order of several 10,000's stb) to be injected over 5-10 days to expect sufficient pressure pulse at downdip injectors A frack boat would be required to bring required volumes of fresh water to the rig for injection Seabed pressure gauge in at least one downdip injection well (CI1, CI2, CI3, CI4) would be required to be able to deconvolute tidal effects Reservoir pressure from downhole gauges in CI1, CI2, CI3, or CI4 could be retrieved from wellhead with telemetry technology (e.g. Sonardyne) Alternatively, an extended production test could be considered for CI5 (in replacement for the extended injection pulse test) Would require in-well ESP to lift the reservoir water which would be disposed of overboard thereafter (several 10,000 stb of brine over 5-10 days to induce sufficient depletion 2 to 3 km downdip.	One extended injection test in crestal observation well (CI5)

Table 61 Data Acquisition – Injectivity Testing

11.2 Rig Requirements

As the water depth at Endurance is 60m, a jack-up rig has been assumed for all drilling and completion activity. It is further assumed that the jack-up would use a surface BOP with a dedicated high-pressure (HP) riser to drill subsea wells.

At the time of writing, a decision on the chosen subsea layout is imminent. The options under consideration are a “clustered” subsea layout (i.e. deviated wells drilled from a common drill centre location) or a “distributed” subsea layout (i.e. lower angle/vertical wells distributed over the Endurance structure, tied back to a central injection manifold). It is expected that the distributed subsea layout will be chosen, however this section contains considerations relevant to both options.

In addition to the lower subsea costs, the clustered subsea layout will minimise the number of rig moves as it should be possible to drill multiple wells from a single rig footing. The number of wells possible from a single rig footing will depend upon the available cantilever movement on the selected rig and the spacing requirements between wells[13]. This would reduce the exposure to weather related NPT when looking to perform rig moves.

Whilst the clustered subsea layout will minimise subsea costs and rig moves, it should be noted that the distributed layout lends itself to simpler and shallower (measured depth) wells which offsets the cost of additional rig moves.

It should be noted that for the phase 1 wells, a CO2-service certified rig is not required; however any workover after the start of injection will do, and so the preferred route is to work with rig contractors to achieve suitable capability and certification prior to spud. Initial discussions with two rig contractors about rig suitability for post-CO2 injection operations (e.g. infill drilling, well interventions etc.) indicated that all modifications, certification etc. would be as a result of an update to the rig safety case. Neither rig supplier currently has any jack-up rigs certified for this type of CO2 service.

11.2.1 Rig Capacities

No rig has been selected for the NZT/NEP wells, however it is expected that a “standard” North Sea jack-up will be capable of executing the phase 1 wells given the shallow water depth and simplicity of the wells. The table below contains an outline of the required rig specification

[13] Number of wells from a single rig footing is also dependent on the choice of wellhead and XMT system

Requirement	Specification
Water depth	60m ±
Drilling depth	2,400m MD below rotary table
BOP system	Minimum 5ksi, Top to bottom config: Annular, pipe ram (optional), blind or blind shear ram, choke and kill outlets, pipe ram
Riser	HP riser with connections compatible with for subsea wellhead and surface BOP. Note this is expected to be a rental or purchase item.[14]
Cranes	Subsea crane with heave compensation preferred
Accommodation	>60 for operator & service company personnel (>160 total)
Fluids	Ability to run 2 separate fluids systems (water based / oil based)
Waste management	Equipment to be able to skip and ship oil based drilled cuttings
ROV	Space for 1 work class ROV
Completions	Proven ability to run complex subsea completions
Subsea Tree	Ability to run and install subsea tree
Deck Area	Deck space for completions equipment
Pumps	3 mud pumps - 6000psi operating pressure - as a minimum
Hoisting capability	1,000klbs

Table 62 Outline Rig Specification

Initial meetings with a rig contractor who have a significant fleet of jack-up rigs indicated that their 100 or 120 series jack-ups would be suitable to deliver the wells work scope including the ability to run a subsea Xmas tree. An example specification for a 120 series jack-up is provided below:

[14] Manufacturing schedule potentially up to 18 months

Capacities			
Rotary Load	2,500,000 lbs	Potable Water	3,500 bbls
Setback Load	1,450,000 lbs	Drill Water	25,179 bbls
Liquid Capacity	7,500 bbls	Diesel Fuel	4,400 bbls
Bulk Cement	8,440 cu ft	Base Oil	1,470 bbls
Bulk barite	9,200 cuft	Brine	2,100 bbls
Drilling Equipment			
Derrick	NOV 210 ft x 40 ft x 40 ft	Top Drive	1250T NOV TDX-1250
Travelling Block	NOV 872TB1250-8C x 1,250T	Crown Block:	NOV 1250 st
Draw works	NOV ADS30Q 6,000 hp	Rotary	NOV RST 605-H
Prime Movers	(6) CAT 3516CHD Engine x 1603 kW output	Emergency Generator	Cat 3508-B engine with 910 kW
Cementing Equipment:	Halliburton Unit	Torque Wrench / Spinner	(2) NOV ST-160C
Cranes: (1) 120ft boom x 70sT at 35ft radius; (1) 140ft boom x 70sT at 40ft radius; (1) 140ft boom x 70sT at 35ft radius; (1) NOV KMCVCT 1891 pipe handling knuckle boom crane			
Well Control		**Mud System**	
Diverter	Cameron Type CF-B, 49½″ RST	Mud Pumps	(3) NOV 14-P-220 x 2,200 hp
Annular	Hydril GX 18 ¾″ x 10,000 psi	Shale Shakers	(4) NOV Brandt VSM Multi-Sizer
BOP	(2) NOV Shaffer NXT 18 ¾″ 15M Double	Degasser	(2) NOV Brandt DG-12
Primary Rig Characteristics			
Maximum Water Depth	400 ft	Transverse Leg Centres	156 ft
Leg Length	540 ft	Hookload	2,500,000 lbs
Hull Length	246 ft	Cantilever Skid Out	80 ft
Hull Width	250 ft	Substructure Travel	15 ft (port), 17 ft starboard
Max Drilling Depth	40,000 ft	Mud System Max Pressure	7,500 psi
Longitudinal Leg Centres	150 ft	Quarters Accommodation	150 persons
		Heliport	S-61 and S-92

Table 63 Typical Jack Up Specification and Capacity

11.3 Outline Completion Installation Sequence

This is a simple outline programme for the base case wireline perforating in a vertical well:

- Run production liner
- Wellbore cleanout and displace to running fluid
- Run upper completion
- Run Completion Landing String and land tubing hanger
- Run tubing hanger plug (if no lubricator valve in string)
- Pull landing string and Install vertical tree with workover riser
- Pull TH plug if required
- Perforate well on e-line
- Possible surge well back to the rig to clean up
- Pull workover riser
- Install swab cap
- Hand over well

12.0 Life of Well Considerations

12.1 Inherently Safer Design

The key to inherently safer design is to eliminate aspects that may cause risks rather than to mitigate them; what is not there cannot leak.

The key change in this respect is the adoption of an all-subsea layout, which eliminates personnel exposure as would be the case on a NUI.

Furthermore, subsequent well work and intervention activity is confined to single geographically isolated wells, rather than all wells being in close proximity on a platform.

12.2 Intervention Requirements

The intervention forecast has been split into three sections:

12.2.1 Water Washing

Based on GEM modelling for halite deposition, a requirement exists to flush the near wellbore with fresh water. This will be done from a vessel set up to connect to either the tree or manifold in a similar manner to a scale squeeze, initially planned for one wash per well per year; however this is likely to extremely conservative, as based on analogues and planned base-load injection rate, the CO2 – brine interface in the reservoir is likely to be flushed away from the near wellbore and potentially reduce or eliminate issues with halite deposition.

A fully-built up operations programme was developed to generate a cost and schedule for each yearly water washing campaign from a suitably-equipped support vessel. Duration and costs are slightly higher for a distributed (Inline-T) subsea architecture as the boat may have to move between wells.

A breakdown of the water-washing operations can be found in **Table** .

12.2.2 Surveillance and Light Interventions

The planned surveillance programme is comprehensive and comprises a slickline drift run followed by a PLT in each injection well every 5 years. One RST saturation log is also included in the observation well as part of campaign. The surveillance plan has been devised to provide data that will be required by the regulator to monitor CO2 movement in the reservoir – therefore an opportunity exists to build surveillance capability (e.g. fibre optics) into each well to minimise visits from the LWIV; however at this stage, the base case assumes a LWIV campaign every five years, and a comprehensive programme and cost basis has been developed based on current north sea region rates and experience.

As the planned surveillance programme is large, unplanned light interventions have not been included as by comparison they are much less frequent. It is assumed that any interventions required could be appended to the next planned campaign with the incremental cost not being significant.

A summary of the light well intervention surveillance operations can be found in **Table** .

12.2.3 Workovers (Heavy Interventions from a Rig)

"Heavy" interventions involve a tubing pull – for example a safety valve change-out or for a packer leak or tubing repair.

A review of subsea interventions in BP predicted 0.01 heavy interventions per well per year (estimate 40 days per job, or 0.418 days per well per year), and this metric has been assumed for NEP at this stage.

A summary of the workover operations can be found in **Table** 67.

Job	Subsea Layout	Deployment	Campaign Mean Time	Well Mean Time
Surveillance	Clustered	LWIV / SLS Wireline	52 days	1.7 days / well / year
Surveillance	Distributed	LWIV / SLS Wireline	55 days	1.8 days / well / year
Water Washing	Clustered	Vessel with Subsea Connection	13 days	2.1 days / well / year
Water Washing	Distributed	Vessel with Subsea Connection	17 days	2.8days / well / year
Workover	Either	Rig	40 days	0.8 days / well / year

Table 64 Subsea Intervention Schedule

12.2.4 Interventions and OPEX Summary

Using a distributed subsea layout as a conservative case (more vessel moves between wells), adding the relevant rows from **Table** gives the following average metric:

Intervention Operation Time: 5.4 days per well per year

Clearly water washing is the most significant contributor to intervention OPEX, and as explained above, there is the opportunity to reduce the frequency of washes depending on well operational experience.

12.3 Reliability and Availability Model (RAM)

Based on the full intervention programme described above, the wells are available for 360 days per year, or 98.5%. This excludes “waiting on repair” time; however sufficient spare well capacity exists to cope with one well being shut in.

At this early stage of the project, wells operations efficiency is not broken out explicitly in the overall project metric, which assumes an overall 93% OE at the time of writing.

12.4 Well Barrier Schematic at Handover

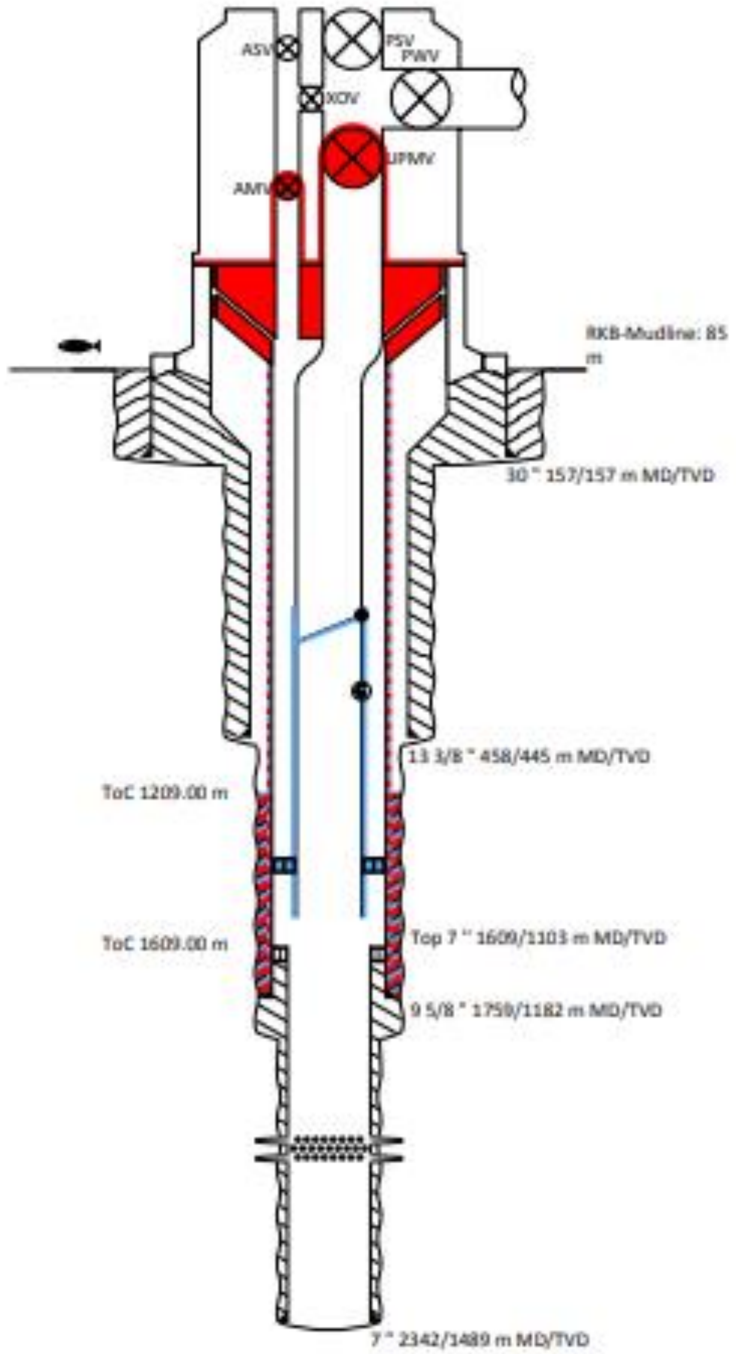
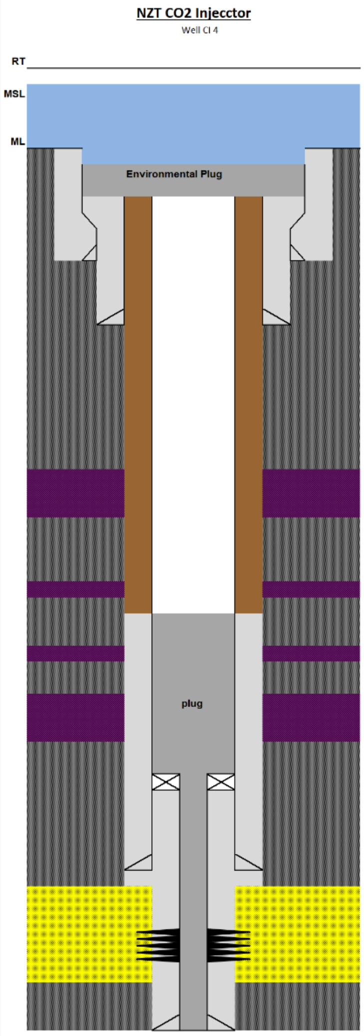


Figure 84 Well Barrier Schematic at Handover

12.5 Abandonment

An example abandonment schematic is shown below in Figure 85. The following points are worth noting:

- Bunter sandstone is assumed to be the only DPZ that requires abandonment.
- The top of the 9-5/8" cement is 450m above the top of the liner. This would mean that it would be possible to permanently abandon the Bunter Sandstone leaving the lower completion in place even if a top of cement method had been used to validate the 9-5/8" cement job during well construction. Note that it is planned to perform a circumferential cement bong log on the 9-5/8" cement job.
- According to the bp zonal isolation practice, there is no need to fill the liner and perfs with cement, however this would help to prevent corrosion.
- It may prove to be advisable to section mill the liner across the natural seal in order to set a full lateral cement plug. This is not currently required to satisfy the bp zonal isolation practice, however it may be required by the regulator.



	mMD BRT	mTVD BRT	mMD SS	mTVD SS	Inclination	Azimuth	Comment
RT	0	0	-25	-25	0	0	
MSL	25	25	0	0	0	0	
Seabed/Mud Line	85	85	60	60	0	0	
30" x 20" Conductor TOC	85	85	60	60	0	0	assume cemented back to ML
20" x 13-3/8" Casing TOC	85	85	60	60	0	0	assume cemented back to ML
Llas	101	101	76	77	0	0	
30" x 20" Conductor	157	157	132	132	0	0	assume 6 joints of conductor
20" x 13-3/8" Casing	458	445	433	420	30	146	assume 13-3/8" set max 30 deg Inc
Winterton (Top Triassic)	587	549	562	524	43	146	
Haisborough	652	594	627	569	49	146	
Top Keuper Anhydrite	679	611	654	586	52	146	
Base KeuperAnhydrite	749	651	724	626	58	146	
Dudgeon	845	701	820	677	58	146	
Dowsing	1046	807	1021	782	58	146	
Top Muschelkalk Halite	1141	857	1116	832	58	146	
9-5/8" Casing TOC	1159	866	1134	841	58	146	assume TOC 600m above shoe (leave lower completion in place for PA)
Top of Cement Plug	1159	866	1134	841	58	146	assume top of plug at same depth as top of 9-5/8" TOC
Base Muschelkalk Halite	1248	913	1223	889	58	146	
Rot Halite 3	1516	1054	1491	1029	58	146	
Rot Halite 2	1538	1066	1513	1041	58	146	
Rot Halite 1	1581	1088	1556	1064	58	146	
7" Liner TOC	1609	1103	1584	1078	58	146	assume cemented back to Liner Top
7" Liner (top)	1609	1103	1584	1078	58	146	assume 150m above 9-5/8" casing
Rot Clay	1746	1175	1721	1150	58	146	
9-5/8" Casing	1759	1182	1734	1157	58	146	assume 9-5/8" midway through rot clay
Bunter Sandstone	1772	1189	1747	1164	58	146	
Top Perf	1829	1219	1804	1194	58	146	assume 30mTVD below top Bunter
Bunter Shale	2327	1481	2302	1456	58	146	
7" Liner	2342	1489	2317	1464	58	146	assume set at TD
TD	2342	1489	2317	1464	58	146	

Figure 85 NZT/NEP Abandonment Design

13.0 Terms and Definitions

APB	Annular Pressure Buildup
API	American Petroleum Institute
BHCT/BHST	Bottom Hole Circulating Temperature / Bottom Hole Static Temperature
BOP	Blow Out Preventer
CGR	Condensate Gas Ratio
DPZ	Distinct Permeable Zone
E&A	Exploration and Appraisal
ECD	Equivalent Circulating Density
EDP	Emergency Disconnect Package
FWHP	Flowing Well Head Pressure
ID	Internal Diameter
Kh	Horizontal Permeability
LRP	Lower Riser Package
MAASP	Maximum Allowable Annulus Surface Pressure
MAWHP	Maximum Anticipated Well Head Pressure
MD	Measured Depth
MEG	Monoethylene Glycol
NSSMC	Nippon Steel Sumitomo Metal Corporation
OD	Outside Diameter
OHGP	Open Hole Gravel Pack
OPEX	Operating Expenditure
PAD	Pump and Dump
PPFG	Pore Pressure Fracture Gradient
ROV	Remotely Operated Vehicle
SCSSSV	Surface Controlled Subsea Safety Valve
SMYS	Specified Minimum Yield Strength
SOBM	Synthetic Oil Based Mud
TD	Total Depth
TVD/ TVDSS	True Vertical Depth / True Vertical Depth Sub Sea
UCS	Unconfined Compressive Strength
WBM	Water Based Mud
WBS	Wellbore Stability
WCD	Worst Credible Discharge
WGR	Water Gas Ratio
WT	Wall Thickness

Table 65 Terms and Definitions